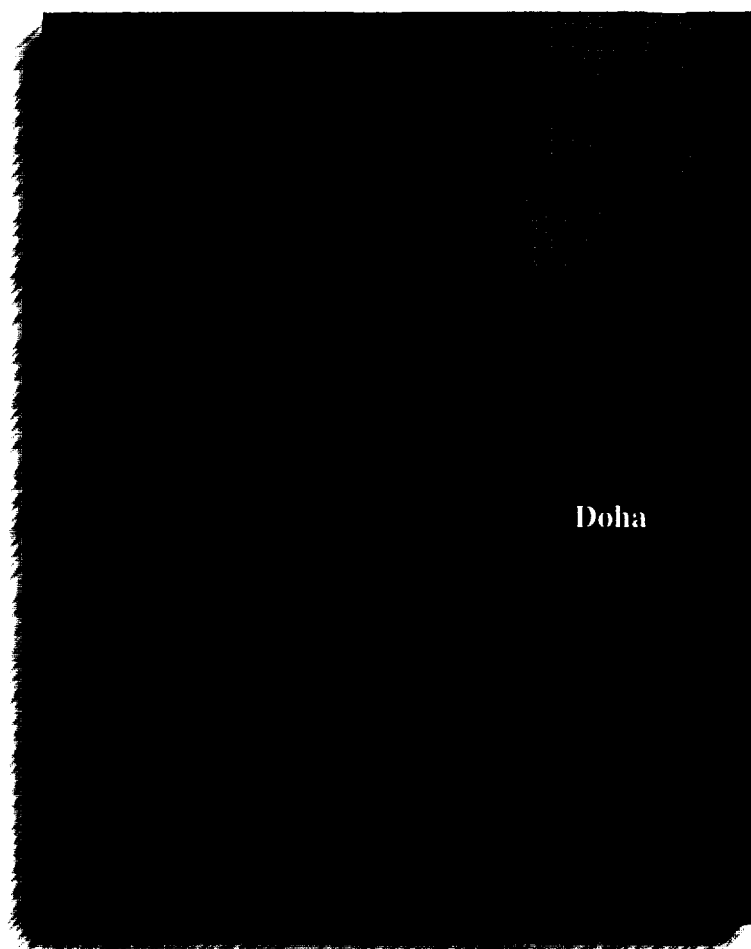




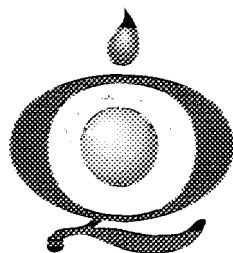
SECOND DOHA CONFERENCE ON NATURAL GAS

***MIDDLE EAST GAS:
PROSPECTS & CHALLENGES***



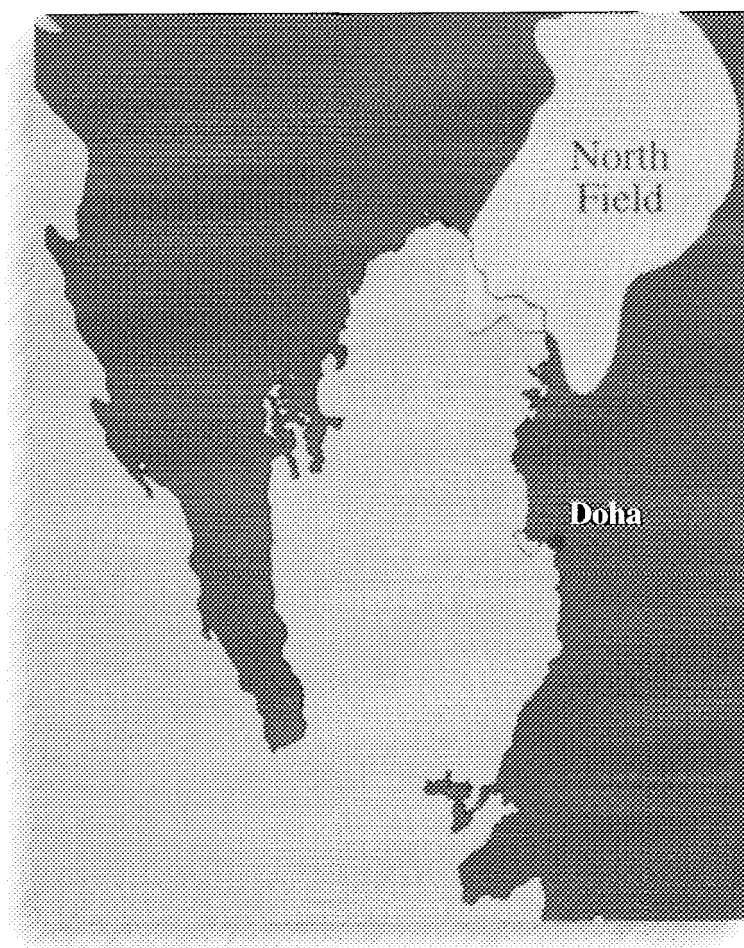
Doha

CONFERENCE BOOK



SECOND DOHA CONFERENCE ON NATURAL GAS

*MIDDLE EAST GAS:
PROSPECTS & CHALLENGES*



CONFERENCE BOOK

March 17 - 19, 1997
Doha - Qatar



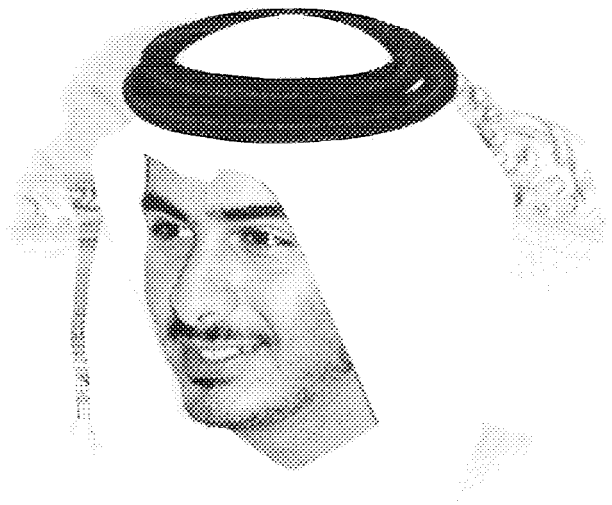
HH Sheikh Hamad Bin Khalifa Al- Thani

Emir of the State of Qatar



HH Sheikh Abdullah Bin Khalifa Al- Thani

Prime Minister and Minister of Interior



HH Sheikh Jassem Bin Hamad Al- Thani

Heir Apparent

**Message from the
Chairman of the
Higher Organizing Committee**



It is my pleasure to welcome you to the Second Doha Conference on Natural Gas, which is being held under the auspices of His Highness Sheikh Hamad bin Khalifa Al-Thani, Emir of the State of Qatar. I wish to express our deep appreciation to His Highness for his valuable support and gracious patronage of this Conference.

The Second Doha Conference is being held under the theme : "Middle East Gas : Prospects and Challenges". Indeed, natural gas reserves in the Middle East are quite significant, and demand for gas in consuming countries continues to increase.

Since the last Doha Conference two years ago, the LNG exports from the Qatargas Project have started, Qatar's Ras Laffan LNG Project is being implemented, and a number of LNG and pipeline projects in Qatar and in other Middle Eastern countries are at various stages of development. Thus prospects are high, and challenges are surmountable.

The Second Doha Conference on Natural Gas is a forum for those concerned with and interested in the gas industry and its future : producers & consumers, sellers & buyers, licensors, contractors, shipyards, financiers, consultants, etc... We are proud to have you in Doha.

I wish to express our gratitude to QGPC as Conference Organizer, to Qatargas and Ras Laffan LNG companies for their co-sponsorship of this Conference, and to Total, Mobil, Marubeni and Mitsui who have joined QGPC in extending financial and material support to the Conference.

**Abdulla Bin Hamad Al-Attiyah
Minister of Energy & Industry**

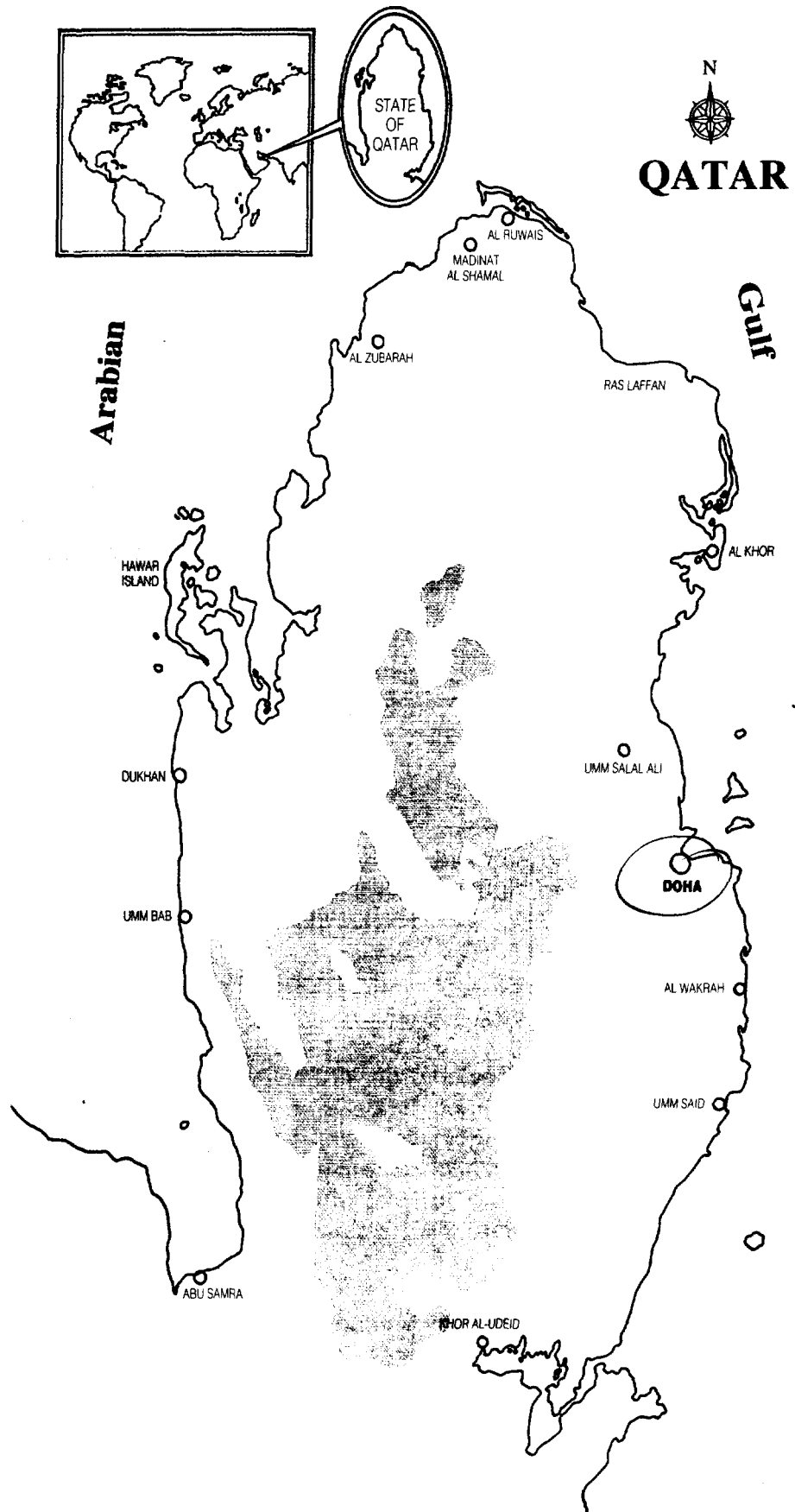
QATAR

The State of Qatar lies nearly midway along the Western coast of the Arabian Gulf. It is a peninsula, with an area of 11,347 square kilometers (approximately 160 km in length and 80 Km at its widest), in addition to several surrounding islands.

Qatar's ancient history is rather closely linked to the history of the Gulf region and the Arabian Peninsula; its modern history begins with the emergence of the Al-Thani rule in the 19th Century. The State of Qatar proclaimed independence on September 3rd, 1971. Since then the country has witnessed a full scale development process.

Qatar is a member of the Gulf Cooperation Council, the United Nations and the Arab League. It is an active member of the Organization of Petroleum Exporting Countries (OPEC), and the Organization of Arab Petroleum Exporting Countries (OAPEC), as well as several other regional and international organizations, such as the World Bank, the International Monetary Fund, UNESCO, FAO, WHO and ILO.

Qatar's economy is closely linked to its oil and gas resources. Qatar has been an oil exporting country for nearly five decades. Qatar is a gas-rich country ranking third worldwide ; it has become a gas (LNG) exporting country at the end of 1996.



STATE OF QATAR



QATAR GENERAL PETROLEUM CORPORATION

Qatar General Petroleum Corporation was established in 1974 as a state-owned corporation to be responsible for all phases of the oil and gas industry in Qatar and abroad.

In two decades, QGPC has made an effective contribution to Qatar's full-scale development process and has realized significant achievements in developing the country's hydrocarbon resources and related industries and investments, in addition to the training and development of the national human resources involved in this vital section; QGPC has given due attention to safety considerations and environmental protection.

QGPC operations and activities in Qatar are carried out in various onshore locations including: Doha, Mesaieed, Dukhan and Ras Laffan, and in offshore areas including Halul Island, production stations and drilling rigs operating in offshore oil fields and the North Gas Field:

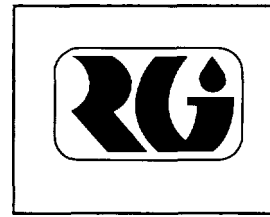
- * QGPC produces onshore crude from Dukhan field and offshore crude from Maydan Mahzam, Idd Al-Shargi and Bul Hanin fields; oil production conforms with OPEC's decisions. Qatar's refining capacity stands at 62,500 barrels per day.
- * QGPC produces associated gas from onshore and offshore oil fields and non-associated gas from the North Gas Field. The utilization of natural gas in Qatar dates back to 1963 when gas was first used as fuel for power generation.
- * QGPC has enhanced its oil production capabilities and increased its exploration and drilling activities in potential onshore and offshore areas, based on production-sharing type agreements with international oil companies: Occidental, Maersk, Elf, Pennzoil, ARCO, etc....
- * QGPC has established many large-scale and export-oriented gas-based industries at the Mesaieed Industrial Area. These include large fertilizers and petrochemical complexes; a methanol/MTBE plant is under construction.
- * QGPC is implementing a phased plan to develop and utilize the massive reserves of non-associated natural gas in the North Gas Field. Stage 1 of the North Field Development Project with a capacity of 800 million cubic feet per day was completed in 1991; it produces lean gas and ethane for domestic/industrial uses, in addition to 50,000 b/d of condensate and natural gas liquids. Other stages provide feedgas for LNG production.
- * The Ras Laffan Industrial City (RLIC), along with its huge port and the Qatargas LNG project, has been inaugurated in February 1997. RLIC will site the Ras Laffan LNG project, which is under construction, and other future gas-export projects, gas-based industries, and condensate refineries.



QATAR LIQUEFIED GAS COMPANY

Qatar Liquefied Gas Company (Qatargas) was established in 1984 to own, construct, and operate an LNG plant in Qatar.

The two-train/4 million tonne per annum LNG facilities, with exports destined to Chubu Electric Power Company Inc., have been completed. The third train/2 million tonne per annum facilities are due for completion by the end of 1998, with production going to seven Japanese utility and gas companies.



RAS LAFFAN LNG COMPANY

Ras Laffan LNG Company Ltd., (RasGas) was established in 1993 to own and implement a gas production/gas liquefaction project to produce 10 million or more tonnes per annum of LNG.

The first phase : a two-train/5 million tonne per annum project, with production destined to Korea Gas Corporation, is under construction. LNG production will commence in mid 1999.

QATAR/RAS LAFFAN LNG SHAREHOLDERS



65% in Qatargas
70% in Ras Laffan
LNG

QGPC, the state-owned corporation established in 1974, is responsible for all phases of the oil and gas industry, in Qatar and overseas.

QGPC has established an efficient gas distribution network to supply fuel gas to power and water desalination plants and fuel and/or feedstock gas to fertilizer, petrochemical, iron & steel, cement, NGL plants, etc...

QGPC's gas experience is highlighted by the successful completion of stage I of North Field Development in 1991 for the production of 800 MMscfd.



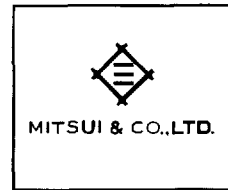
10% in Qatargas

TOTAL, is one of the largest oil companies in Europe with interests in every segment of the oil industry, exploration and production of oil and gas, shipping and in refining and marketing of petroleum products. As a substantial producer of oil and gas in the Middle-East and Indonesia, Total has become a major supplier of energy to Japan and Asian countries with expertise for many years in the ADGAS (Abu Dhabi), and BONTANG (Indonesia) LNG Projects, and in other LNG ventures currently under study.



10% in Qatargas
30% in Ras Laffan
LNG

MOBIL, one of the major oil companies in the world, has historically a long and wellknown record of LNG experience through its subsidiary MOBIL OIL Indonesia with the discovery of the Arun gas field in the early 70's and as contractor of the three Arun LNG trains, expanded to six between 1978 and 1987, geared to Japanese and Korean customers.



7.5 in Qatargas

MITSUI & CO Ltd, an important trading company, provides a significant share of Japanese energy demand by supplying crude oil, fuel oil LNG and LPG to electric power companies and petrochemical industries. In the LNG business, MITSUI actively participates as a shareholder of ADGAS (Abu Dhabi) and North West Shelf project (Australia).



7.5 in Qatargas

MARUBENI Corporation is one of Japan's leading general trading houses with well established and numerous Middle-East branches. Engaged in all stages of energy distribution, from upstream to downstream, MARUBENI is offering a variety of energy sources and related items: crude oil, petroleum products, LPG, thermal coal and nuclear fuel.

**SECOND DOHA CONFERENCE
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DOHA - QATAR



مؤتمر الدوحة الثاني للغاز الطبيعي

١٧ - ١٩ مارس ١٩٩٧

الدوحة - قطر

"Middle East Gas : Prospects & Challenges"

PROGRAMME

MARCH 16, 1997

14.00 - 22.00	Registration
17.00 - 18.00	<i>Opening of Exhibition</i>
19.30 - 21.00	Reception

Day 1 (MARCH 17, 1997)

07.30 - 08.30	Registration
09.00 - 09.30	Opening Ceremony <ul style="list-style-type: none">- Address by His Highness Sheikh Hamad Bin Khalifa Al-Thani, Emir of the State of Qatar.- Address by His Excellency Mr. Abdullah Bin Hamad Al-Attiyah, Minister of Energy and Industry.
09.30 - 10.00	Coffee Break
10.00 - 12.30	<u>SESSION 1 : The Gas Challenge</u> Chairman : H. E. Abdullah Bin Hamad Al-Attiyah, Minister of Energy and Industry, State of Qatar <ul style="list-style-type: none">• Congratulatory Message B. Kino, Managing Director, Chubu Electric Power Co., Inc., Japan• Keynote Speech : Realities of the Gas Challenge Sheikh Ahmed Zaki Yamani, Chairman, Centre for Global Energy Studies, U.K.• Middle East Gas : The Market Challenge James Ball, Managing Partner, Gas Strategies, U.K.
12.30 - 14.00	Lunch hosted by Total
14.00 - 15.30	<u>SESSION 2 : Middle East Gas Supply</u> Chairman : H. E. Yousef Kamal, Undersecretary, Ministry of Finance, Economy and Trade, State of Qatar

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مؤتمر الدوحة الثاني للغاز الطبيعي

١٧ - ١٩ مارس ١٩٩٧

الدوحة - قطر

- Middle East Gas Reserves, Development Plans, and Future Prospects.
M. F. Chabrelie, General Secretary, Cedigaz, France
- Middle East Gas : Utilization, Development, and Policies
Dr. Robert Mabro, Director, Oxford Institute for Energy Studies, U.K.

15.30 - 16.00

Coffee Break

16.00 - 17.30

SESSION 3 : Qatar's Gas

Chairman : Faisal M. Al-Suwaidi, Vice Chairman, Qatar Liquefied Gas Company Ltd., Qatar

- The Gas Industry In Qatar : Strategies & Options.
Nasser K. Jaidah, Director, Exploration & Development of New Ventures, Qatar General Petroleum Corporation, Qatar
- Development & Implementation of the Qatargas Project.
Abdul Redha Abdul Rahman, General Manager, Qatar Liquefied Gas Company Limited, Qatar
- The Ras Laffan LNG Company : The Commitment of Today, the Challenge of Tomorrow.
Neil Kelly, Managing Director, Ras Laffan Liquefied Natural Gas Company, Qatar

19.30

Dinner hosted by QGPC

Day 2 (MARCH 18, 1997)

09.00 - 10.30

SESSION 4 - Panel Discussion : Natural Gas Demand in the Far East / Prospects for Middle East Gas

Chairman : Jim E.Harrison, President, Mobil LNG Inc., U.S.A.

Co Chairman : Pierre-Rene Bauquis, Advisor to the President, TOTAL, France

- The Future of Middle East Gas in Japan
Yuzuru Aoki, Representative Managing Director, Tohoku Electric Power Co., Inc., Japan

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مؤتمر الدوحة الثاني للغاز الطبيعي

١٧ - ١٩ مارس ١٩٩٧

الدوحة - قطر

- **Natural Gas Demand in the Far East**
Sjahrial Daud, Director of Foreign Marketing,
Pertamina, Indonesia
- **The Asia Pacific Gas Market A Question of Balance**
Russell Jacobs, Vice President/Director, Purvin &
Gertz, U.S.A.
- **Natural Gas Demand Prospects in Korea**
Young-Jin Kwon, Executive Vice President, Korea Gas
Corporation, Korea
- **Natural Gas Utilization in Taiwan**
H. C. Chang, Vice President, Chinese Petroleum
Company, Taiwan

10.30 - 11.00

Coffee Break

11.00 - 12.30

**SESSION 5 - Panel Discussion : Natural Gas Demand
in Europe / Prospects for Middle East Gas**

**Chairman : Pierre-Rene Bauquis, Special Advisor to
the President, TOTAL, France**

**Co Chairman : R. D. Nelson, Vice President of LNG
Venture Development, Mobil LNG Inc., U.S.A.**

- **Prospects For Middle East Gas in Europe**
Michael Tusiani, Chairman & Chief Executive Officer,
Poten & Partners, U.S.A.
- **The Future of Middle Eastern Gas in Europe**
Domenico Dispenza, Director Gas Supply, SNAM, Italy
- **Natural Gas Demand Prospects in Europe**
Eberhard Lange, Head of Gas Purchase South
Department, Ruhrgas, Germany
- **Prospects for Middle East Gas in Europe**
Mourad Preure, Sonatrach, Algeria
- **Prospects for Middle East Gas in Europe**
Nikoly I. Belyi, Director, Gazprom, Russia
- **Natural Gas Demand Prospects in Europe**
Nuran Satana / Serpil Soylu, International Research
Chief Engineer, BOTAS, Turkey
- **Gas link between the Gulf and Western Europe:
Projects, Challenges and Prospects**
Dr. Naji Abi-Aad, OME Senior Consultant,
Observatoire Mediterranee de L'Energie, France

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الدوحة - قطر

12.30 - 14.00

Lunch hosted by Mobil

14.00 - 15.30

SESSION 6 : Natural Gas & Power Generation

**Chairman : Dr. Ibrahim Ibrahim, Economic Advisor,
Emiri Diwan, Qatar**

- **Demand Prospects for Gas in Emerging Economies**
R.F. Guerrant , President, Mobil Power Inc., U.S.A.
- **LNG for Power Plants / The BOT Route**
Richard P. (Rick) Bergsieker, Managing Director,
Enron Development Corp., U.S.A.
- **LNG Plant Combined with Power Plant**
Ichizo Aoki, Director / Yoshitsugi Kikkawa Chiyoda
Corp., Japan

15.30 - 16.00

Coffee Break

16.00 - 17.30

**SESSION 7 - Panel Discussion : Natural Gas Demand
in Emerging Markets**

**Chairman : Jerry R. Schuyler, Regional Vice President
& Managing Director, ARCO, U.A.E.**

- **The GCC Gas Pipeline**
H.E. Dr. Abdul Rahman Al-Jafari, Secretary General,
GOIC, Qatar
- **Prospect for Middle East Gas in India**
R.P. Sharma, Executive Director (MKTG & PLNG), Gas
Authority of India, India
- **Natural Gas Demand in Thailand**
Chaichaream Atibaedya, Sr. Vice President, Thai LNG
Power Corp. Ltd., Thailand
- **Natural Gas Demand in Emerging Markets**
Edward Walshe, Managing Director, Special Projects -
Exploration and Production, British Gas, U.K.

19.30

Dinner hosted by Qatargas

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مؤتمر الدوحة الثاني للغاز الطبيعي

١٧ - ١٩ مارس ١٩٩٧

الدوحة - قطر

Day 3 (MARCH 19, 1997)

09.00 - 10.30

**SESSION 8 : The LNG Chain : Technological
Innovations and Cost Reduction**

**Chairman : Abdul Razzaq M. Al-Siddiqi, Director
Technical, QGPC, Qatar**

- **Reducing Capital and Operating Costs in Gas Processing, Liquefaction, and Storage**
L. C. "Fritz" Krusen, Principal Engineer, Global Gas Group, Philips Petroleum, U.S.A.
- **The PRICO Cycle, The Low Cost Alternative to LNG Production**
Ram R. Tarakad, Brown & Root Engineering & Const. /
Brian C. Price, The Pritchard Corporation, U.A.E.
- **Conversion of Natural Gas into Liquid Fuels**
L.P.A Davies, Group General Manager, Sasol Limited, South Africa
- **Reducing LNG Transportation Costs : Prospects and Challenges**
Charles H.W. Peile, Commercial Vice President /
Richard G. Eddy, Gotaas Larsen, U.K.

10.30 - 11.00

Coffee Break

11.00 - 12.30

**SESSION 9 - Panel Discussion : Safety &
Environmental Considerations in LNG Operations and
Transportation**

**Chairman : Dr. Mohammed Al-Sada, Manager, Safety,
Quality & Environment, QGPC, Qatar**

- **Safety Aspects of the LNG Transportation Link**
Alain Vaudolon, General Manager, Sigtto, U.K.
- **Halon 1301 Replacement in ADGAS Installations**
**Abdullah Mattar Al-Zaabi, Deputy Head of Safety &
Loss Prevention, Adgas, U.A.E.**
- **Qatargas Crisis Preparedness**
**Rick Mire, Safety & Environment Manager, Qatargas,
Qatar**



- **Safety & Environmental Aspects in LNG Carrier Design**
Takashi Yoneyama, Project Manager, Ship Basic Design Department, Mitsui Engineering & Shipbuilding, Japan
- **The Challenge for Safe Transportation of LNG**
T. Hojo, Director, Mitsui O.S.K Lines, Ltd., Japan
- **LNG Plant : Safety Considerations**
Michel Halata, Plant Operation Manager, The M.W. Kellogg Co., U.S.A.

12.30 Lunch hosted by Ras Laffan LNG

14.00 - 16.00 **SESSION 10 : Economic and Financing Challenges**
Chairman : Dr. Hussain Al-Abdulla, Project Finance Team Leader, QGPC, Qatar

14.00 -14.30 **Financing LNG Projects - the Role of the Capital Markets Going Forward.**
Daniel S. Lief, Vice President, Investment Banking Division, Goldman Sacs & Co., U.S.A.

14.30 - 16.00 **Panel Discussion : Financing LNG Projects**

- **The Export-Import Bank of Japan and LNG Development Projects**
Koichi Fujii, Director General, Project & Corporate Analysis Dept, J-EXIM, Japan
- **Financing LNG Projects**
Jean O. Facon, Managing Director, JP Morgan, U.K.
- **Financing LNG Projects**
Dianne S. Rudo, Vice President, US EXIM, U.S.A.
- **Financing LNG Projects**
Craig Bennett, Director - Project Finance, Societie Generale, France
- **The Role of Regional Financial Institutions in Financing Future LNG Projects in the Gulf**
Ahmed Nabil, Senior Officer-Project & Trade Finance, Apicorp, Saudi Arabia
- **Financing LNG Projects**
Mr. Humbert de Wendel, Head of Dept., Finance Division, TOTAL, France

**SECOND DOHA CONFERENCE
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مؤتمر الدوحة الثاني للغاز الطبيعي

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الدوحة - قطر

16.00 - 16.30

Coffee Break

16.30 - 17.30

FINAL SESSION

**Chairman : H.E. Mr. Abdullah Bin Hamad Al-Attiyah,
Minister of Energy and Industry, State of Qatar**

MARCH 20, 1997

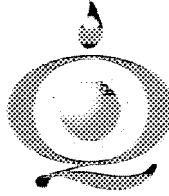
09.00 - 13.00

Visit to Ras Laffan Industrial City

**SECOND DOHA CONFERENCE
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مؤتمر الدوحة الثاني للغاز الطبيعي

١٧ - ١٩ مارس ١٩٩٧

الدوحة - قطر

SPEAKERS' PROFILES

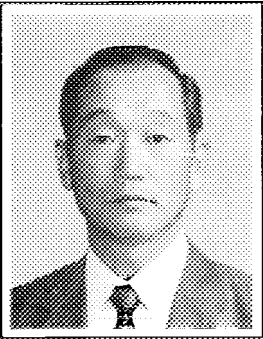
H.E. Abdulla Bin Hamad Al-Attiyah

Chairman of Session (1) : The Gas Challenge

HE Abdulla bin Hamad Al-Attiyah is Minister of Energy and Industry, State of Qatar, and Chairman & Managing Director of Qatar General Petroleum Corporation (QGPC), since September 1992.

H.E. Al-Attiyah started his career with the Ministry of Finance & Petroleum, where he was Head of International and Public Relations from 1973, and Director of the office of the Minister of Finance and Petroleum from 1986, when he assumed the post of Director of the office of the Minister of Interior.

H.E. Al-Attiyah is Chairman of Qatar Liquefied Gas Company (Qatargas), Qatar Petrochemical Company (QAPCO), and Qatar Fuel Additives Company (QAFAC). He is also Chairman of Gulf Helicopters, Director of Gulf Air, Chairman of Al Sad Sports Club and Chairman of Qatar Radio Amateur Association.



B. Kino

Congratulatory Message

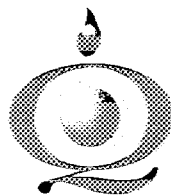
Bunkai Kino is Managing Director of Chubu Electric Power Co., Inc. since June 1993. He joined the company in April 1959 upon graduation from the Faculty of Law at Keio University. After working in several capacities in the company, he was promoted to Senior General Manager (1987) and to Executive Director (1989).

H.E. Sheikh Ahmed Zaki Yamani

Keynote Speech : Realities of the Gas Challenge

SECOND DOHA CONFERENCE ON NATURAL GAS

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مؤتمر الدوحة الثاني للغاز الطبيعي

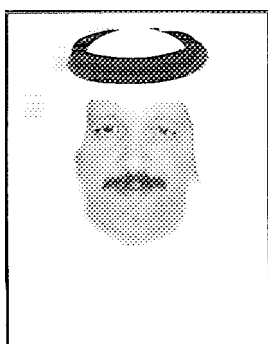
١٧ - ١٩ مارس ١٩٩٧

الدوحة - قطر

James Ball

Middle East Gas : The Market Challenge

James Ball is one of two Managing Partners of Gas Strategies. He is Managing Director of EconoMatters (one of Gas Strategies parent companies) and a partner in the management training Alphantania Partnership, co-authoring the Alphantania Case Study. He has an extensive network of contacts in the international gas scene and an exceptionally wide knowledge and understanding of the international gas business, with particular interests being West European gas markets, power market strategies for gas, and international LNG markets.



H. E. Yousef H. Kamal

Chairman of Session (2) : Middle East Gas Supply

H. E. Yousef H. Kamal is Undersecretary, Ministry of Finance, Economy and Trade in the State of Qatar since July 1993, and is Vice Chairman of QGPC and Chairman of Ras Laffan Liquefied Natural Gas Company (RasGas). He is also Chairman of Doha Stock Exchange, Vice Chairman Qatar Steel Company (QASCO), and Qatar Telecommunication (Q-Tel), and Director of Qatar National Bank and OPEC Special Fund.

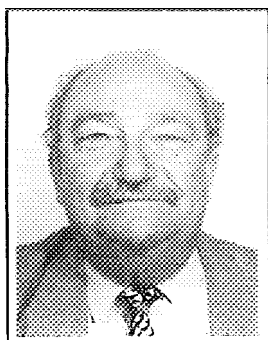
Mr. Kamal started his career at the Department of Finance upon graduation with a B.A. degree in Business Administration from Cairo University (1973), where he progressively held senior posts.



M. F. Chabrelie

Middle East Gas Reserves, Development Plans, and Future Prospects

Marie-Francoise Chabrelie is General Secretary and Editor of CEDIGAZ, a non-profit international association devoted to gas information, which has 190 members among major oil and gas companies and international organizations. She is in charge of CEDIGAZ's publications, in particular the worldwide annual report on natural gas and her studies on Planned Gas Pipelines Around the World and European Natural Gas Trade by Pipelines. She holds a post-graduate degree in energy economics from the Ecole Nationale Supérieure du Pétrole et des Moteurs (Rueil Malmaison, France).



Dr. Robert Emilie Mabro

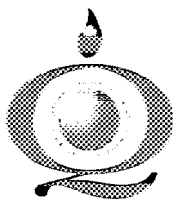
Middle East Gas : Utilization, Development, and Policies

Dr. Robert Emilie Mabro is Fellow of St. Anthony's College, Oxford and Director of the Oxford Institute for Energy Studies. In December 1995, he was awarded a CBE by HM the Queen in the New Year's Honours List.

SECOND DOHA CONFERENCE ON NATURAL GAS

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مؤتمر الدوحة الثاني للغاز الطبيعي

١٧ - ١٩ مارس ١٩٩٧

الدوحة - قطر

Dr. Mabro obtained a degree in civil engineering from Alexandria University (1956), went to France to study philosophy (1962-4) and then to London University where he obtained an MSc in economics, with distinction, in 1966. He began his academic career at the School of Oriental and African Studies at London University.

Since 1969 Dr. Marbo has continued as University Teacher and as Fellow of St. Anthony's College at the University of Oxford, supervising postgraduate students and lecturing on the economics and politics of oil. His interest in oil began to develop in 1972/3 ; in 1976 he founded the Oxford Energy Policy Club which still meets twice a year at St. Anthony's College. Two years later he founded and became the first Director of the Oxford Energy Seminar, which is held every year in September, and next he founded the Oxford Institute for Energy Studies.

In December 1991 Dr. Marbo was awarded the International Association for Energy Economics' 1990 Award for Outstanding Contributions to the Profession of Energy Economics and to its Literature. In 1993, he became the Vice Chairman of the Board of Trustees of the Economic Research Forum for the Arab countries, Turkey and Iran.

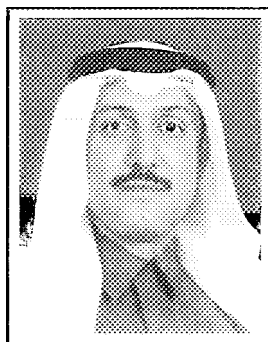


Faisal M. Al-Suwaidi

Chairman of Session (2) : Qatar's Gas

Faisal M. Al-Suwaidi is Vice-Chairman of Qatargas Board of Directors and Managing Director of Qatar Fertiliser Company, since 1992. He joined QPC in October 1972, joined Merton Technical College at Wimbeldon in 1974 and obtained his Diploma in Business Management in 1978. On his return he joined the Personnel Department ; became Personnel Manager of QGPC (HQ) in 1986 and Administration Manager in 1989.

Mr. Al-Suwaidi is also member of the Board of Directors of QGPC, Chairman of the Board of Trustees for QGPC Corporate Training Centre and Chairman of the Mesaieed Industrial Area Development Committee.



Nasser K. Jaidah

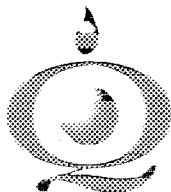
Qatar's Gas Utilization & Export Projects

Nasser K. Jaidah, Director of New Ventures at Qatar General Petroleum Corporation (QGPC) since May 1993, holds a B.Sc. in Geology from Western Michigan University (1976). He joined QGPC in 1977 as a Wellsite Petroleum Engineer, and then Production Geologist, and spent a one year assignment in Qatar Exploration Team in The Hague. He then served in the following capacities at QGPC : Head of Economics and Planning, Head of Engineering Operations, Petroleum Engineering Manager, Technical Manager, and Exploration and Production Manager.

Mr. Jaidah is a Director of Qatar Liquefied Gas Company (QATARGAS), and Chairman of three Upstream Ventures committees.

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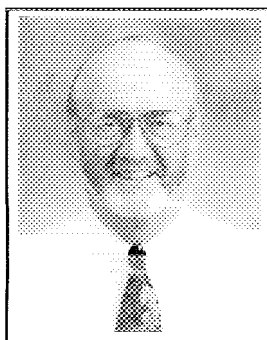
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Abdul Redha Abdul Rahman

Development & Implementation of the Qatargas Project

Abdul Redha Abdul Rahman is a Director of Qatar Liquefied Gas Company since 1992 and became its General Manager in February 1994. His career started with Qatar Fertilisers Company in 1972, and became Deputy General Manager. In 1989, he moved to Qatar Petrochemical Company as Deputy General Manager. He moved to QGPC in 1991 to take up the assignment of Manager, Manufacturing and Investment Department where he was actively involved in the planning and development of gas export and gas processing projects, including LNG and petrochemicals. He also guided the development of the Ras Laffan Industrial Area as Project Manager for Ras Laffan Port and Facilities.



Neil B. Kelly

The Ras Laffan LNG Company : The Commitment of Today, The Challenge of Tomorrow

Neil B. Kelly is Managing Director of Ras Laffan Liquefied Natural Gas Company Limited. He holds both B.Sc. (Hons) and M.Sc. degrees in Mechanical Engineering from the University of Strathclyde in Scotland, and has carried out post graduate work in Mechanical Engineering at Queens University in Canada.

Mr. Kelly has spent 28 years in the oil and gas industry, 18 of them with Mobil. His previous experience includes various engineering, project and operations assignments. He was Platform Manager on Statfjord 'A' platform and Operations Manager in Nigeria. He spent six years in Indonesia responsible for the Arun gas field production and Mobil's interest in the Arun LNG plant, and was involved in both operations and technical management at the LNG plant. He was also a Director of the PT Arun LNG Co.



Jim. E. Harrison

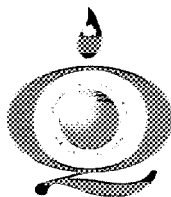
Chairman of Session (4) : Natural Gas Demand in the Far East/Prospects for Middle East Gas

Jim Harrison is President and General Manager of Mobil LNG Inc. since November 1995. He is also a Director of the Ras Laffan Liquefied Natural Gas Company Limited.

Mr. Harrison received his Bachelor's degree in Chemical Engineering in 1966 and joined Mobil as a Production Engineer and held several positions in engineering and operations, planning and project development. In 1977, he left Mobil to join Superior Oil Company in Houston, Texas, where he held several management positions. He returned to Mobil in 1985 after Mobil's acquisition of Superior Oil. In 1991, he was appointed President & General Manager of Mobil Exploration Norway in Stavanger. In April of 1993 he assumed the position of President and General Manager of Mobil Oil Qatar Inc., and

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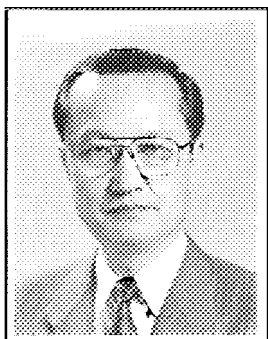


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held the positions of Managing Director of the Ras Laffan Liquefied Natural Gas Company Limited and a director of Qatar Liquefied Natural Gas Company Limited.



Yuzuru Aoki

The Future of Middle East Gas in Japan

Yuzuru Aoki is Representative Managing Director of Tohoku Electric Power Co., Inc. since June 1992. He joined Tohoku Electric upon graduation from the Faculty of Economics at Tohoku University in 1958, and was subsequently promoted to Deputy General Manager of Fuels Dept. (1981), Senior Officer & General Manager of Customer Services & Sales Dept. (1987), and Director & General Manager of Corporate Planning Dept. (1991).

Sjahrail Daud

Natural Gas Demand in the Far East

Sjahrail Daud is Director of Foreign Marketing at PERTAMINA since 1994. He graduated from the Faculty of Economics at the University of Indonesia.

Mr. Daud joined Pertamina in 1977 where he occupied several positions, including Head of Crude Oil Supply and Distribution, Head of Sales Programming and Head of Sales Operations. He became General Manager of the Oil and Gas Marketing Development Department in 1991.



Russell H. Jacobs

The Asia Pacific Gas Market - A Question of Balance

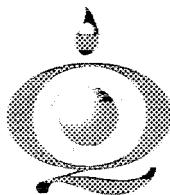
Russell H. Jacobs is Vice President responsible for Purvin & Gertz' global gas consulting activities, and is a member of the firm's Board of Directors. In 1991, he directed a major long term evaluation of LNG and natural gas markets in the Far East, with particular emphasis on the implications to potential LNG suppliers. Since that time, he has been involved in numerous additional regional market and project feasibility analyses.

Prior to joining Purvin & Gertz in 1981, Mr. Jacobs was Manager of Business Development and Planning for the El Paso LNG Company, a subsidiary of El Paso Natural Gas. In this capacity, he managed LNG project assessments in Latin America, Asia, and the Middle East.

Mr. Jacobs holds a degree in Chemical Engineering with high honors from the University of Florida (1968), and is the author of numerous papers and seminars on international natural gas/LNG markets.

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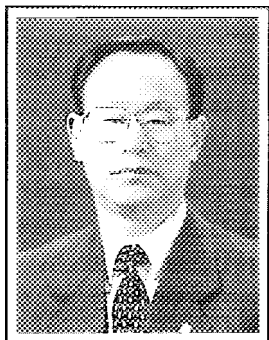
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Young-Jin Kwon

Natural Gas Demand Prospects in Korea

Young-Jin Kwon was appointed Executive Vice President of Korea Gas Corporation, Seoul, Korea in 1995. An electrical engineer, he worked for the Korea Electric Power Corporation for 18 years from 1965 to 1983 before joining Korea Gas Corporation when it was founded in 1983. From 1991 to 1995, he held the following positions in Korea Gas Corporation : Director of Pyeong-Taek LNG Terminal, Director of Planning & Control, Director of Terminal Construction, and Vice President of Construction.

H. C. Chang

Natural Gas Utilization in Taiwan

H. C. Chang is Vice President of the Chinese Petroleum Corporation (CPC). He led the negotiations of LNG Sales/Purchase Agreement with Pertamina and Malaysia LNG. His responsibility also covers crude oil/products supply, domestic marketing and transportation.

Mr. Chang graduated from the National Taiwan University with a major in business administration and joined CPC in 1967. Before that, he worked in crude & products supply ; by 1983, he had 16 years experience in general management which included a 2-year assignment as representative in Saudi Arabia, training in the general petroleum industry at the IFP, and attending an advanced management program at the Harvard Business School.



Pierre-Rene Bauquis

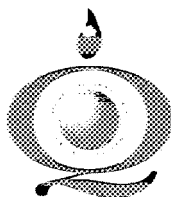
Chairman of Session (5) : Natural Gas Demand in Europe/Prospects for Middle East Gas

Pierre-Rene Bauquis is Special Advisor of the Chairman of TOTAL since March 1995. He joined TOTAL in 1972 and had spent most of his career in gas related activities : GASCO in Abu Dhabi (1973-1978), Head of TOTAL Indonesia Gas Division (1980-1986), Head of the North Sea Division (1989-1992), Senior Vice President Corporate Strategy and Planning (1992-1994), and Director of Gas, Coal and Electricity (1994-1995).

Mr. Bauquis graduated from ENSG (National School of Geology and Mining) and the ENSPM/IFP (French Petroleum Institute). Between 1967 and 1972, he worked with IFP in Economics Department and as Professor of Oil and Gas Economics at ENSPM.

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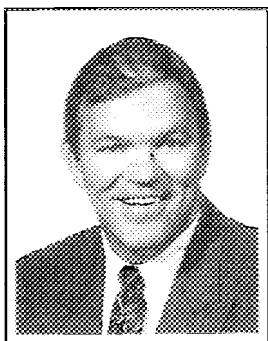
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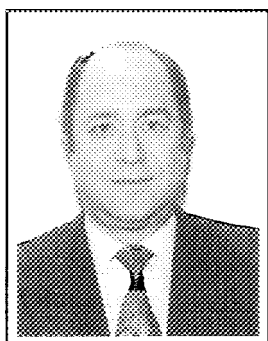


Daniel Nelson

Co-Chairman of Session (5) : Natural Gas Demand in Europe/ Prospects for Middle East Gas

Daniel Nelson is Executive Vice President, Venture Development Mobil LNG Inc., since the beginning of 1996. He is a graduate of the U.S. Naval Academy. After earning a graduate degree in business from George Washington University, he began work for Mobil in 1976, in the supply, distribution and trading area. In 1979, he joined Mobil's Middle East Department, where his assignments included management of consortium participation in ventures in Abu Dhabi and Qatar, new business development in London, and management of Mobil's shareholding in the Arabian American Oil Company (Aramco) ; he was named manager of Mobil's Middle East Department in 1990. In 1994, he became Vice President, Planning. Mobil Sales & Supply Corporation.

Mr. Nelson has served as President, Mobil Middle East Development Corporation, a Director of Samref, the Mobil-Saudi refining joint venture in Saudi Arabia, Vice Chairman of the U.S. - G.C.C. Corporate Cooperation Committee and as Director of American Near East Refugee Aid.



Michael D. Tusiani

Prospects For Middle East Gas in Europe

Michael D. Tusiani is the Chairman and Chief Executive Officer of Poten & Partners since 1983. Prior to joining Poten & Partners in 1973, he was employed by Zapata Corporation where he was primarily involved in LNG and LPG research and development.

Mr. Tusiani has participated in many international petroleum and gas conferences and has published numerous articles and two books on energy and shipping matters. He has also been a member of the Economics faculty at Fordham University in New York City.



Domenico Dispenza

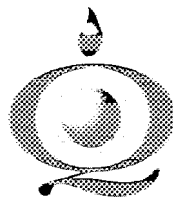
The Future of Middle Eastern Gas in Europe

Domenico Dispenza is Director of Gas Supply at Snam SpA, Milan. In addition, he is Managing Director of Promgas, a joint venture between Snam and Gazprom of Russia. He joined Snam in 1974.

Mr. Dispenza holds an MA in Aeronautical Sciences from Politecnico, Milan, and a Master's in Advanced Technologies.

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Eberhard Lange

Natural Gas Demand Prospects in Europe

Eberhard Lange is Head of the Southern Gas Purchasing Section, in Ruhrgas AG in Essen, Germany. He joined Ruhrgas in 1981, where he has worked on several projects for importing LNG and pipeline gas from various sources and is Statutory Officer of the German LNG Terminal Project Company in Wilhelmshaven.

Mr. Lange studied business management and graduated from the Technical University of Karlsruhe, Germany, in 1973.

Mourad Preure

Prospects of Middle East Gas in Europe

Mourad Preure is Director of Strategy, Sonatarch, Algeria.

Nikoly I. Belyi

Prospects of Middle East Gas in Europe

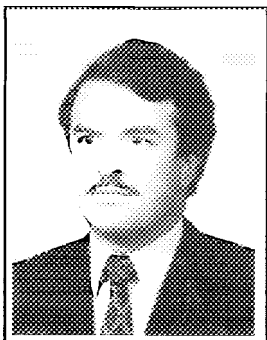
Nikoly I. Belyi is Director of Gazprom, Russia.

H. Nuran Satana & Serpil Soylo

Gas Utilization in Turkey

Ms. H. Nuran Satana is Assistant Head of Natural Gas Group, BOTAS Petroleum Pipeline Corp., Turkey, since February 1997. She graduated from Middle East Technical University-Industrial Engineering Department in 1974. She had worked in the agricultural and machinery sectors and joined BOTAS in 1986, where she worked on Natural Gas planning, purchasing and pricing.

Ms. Serpil Soylo is International Research Chief Engineer in Natural Gas Group, BOTAS Petroleum Pipeline Corp., Turkey, since February 1997. She graduated from Hacettepe University-Chemical Engineering Department in 1984, and also completed her Masters at the same University. She had worked with The Union of Chambers of Turkey (1984-1986) and General Directorate of Electrical Power Research Survey And Development Administration (1986-1988). She has been working for BOTAS Natural Gas Group since 1988.



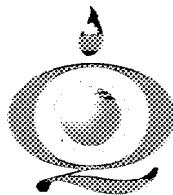
Dr. Naji Abi-Aad

Gas Link between the Gulf and Western Europe : Projects, Challenges and Prospects

Dr. Naji Abi-Aad is senior consultant for the Middle East to the Observatoire Méditerranéen de l'Énergie (OME), an interregional energy research center based in Sophia Antipolis, south of France, with the aim to enhance the co-operation between the energy consumers north of the

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Mediterranean and the producers on the south and east of the basin. He is an energy economist based in Vienna since 1983, and co-operating with OPEC, UNIDO, UNEP and the International Atomic Energy Agency. He has been involved in numerous energy consultations, conferences and studies, particularly on Middle East natural gas, political stability and petroleum supply security, as well as the technical, legal and financial aspects of oil production capacity. He is the author of more than 60 articles, reports and studies on energy in the Middle East.

Dr. Abi-Aad studied at the American University of Beirut, Universite St. Joseph, Beirut, and Webster University, St. Louis-USA ; graduated with degrees in Petroleum Studies, International Law and Energy Economics. He obtained a Ph.D. in energy economics from Universite des Sciences Sociales, Grenoble-France.



Dr. Ibrahim B. Ibrahim

Chairman of Session (6) : Natural Gas & Power Generation

Dr. Ibrahim B. Ibrahim joined Qatar Government in August 1988 as Economic Expert, and is currently an Economic Advisor to His Highness The Emir, and a member of QGPC Board of Directors and Vice Chairman of Ras Laffan LNG Company.

Dr. Ibrahim was an Associate Professor of Business Economics and Quantitative methods at the University of Hawaii, Honolulu. U.S.A. (1970-1978); Director of the Economic Department at the organization of Arab Petroleum Exporting Countries, Kuwait (1979-1986); and a Senior Economist at Oxford Institute for energy studies, Oxford, (1986-1988).

Dr. Ibrahim holds a Ph.D. in Business Administration from New York University (1969) and has numerous publications in the areas of forecasting, Business Economics, and Energy Economics.



R. F. Guerrant

Demand Prospects for Gas in Emerging Economies

R. F. Guerrant, President of Mobil Power Inc., oversees all of Mobil Power Inc. activities worldwide. Since joining Mobil Corporation in 1980, he has held various senior executive positions, including manager of business and competitive strategy in the Exploration and Production division, where he was responsible for Mobil's worldwide investment programs and profit plans.

From 1992 to 1994, Mr. Guerrant served as vice president of Mobil Natural Gas Inc., with responsibilities for sales, purchasing, transportation, risk management and volume management for more than 3.5 billion cubic feet of natural gas in the United States, Canada and Mexico. From 1990 to 1992, as vice president of marketing for Mobil Oil

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Canada, he was responsible for crude, natural gas liquids, sulphur and natural gas marketing.

Mr. Guarrant is a graduate of the University of Texas.

Richard P. Bergsieker

LNG for Power Plants / The BOT Route

Richard P. Bergsieker, Principal, Enron International, is responsible for fuel supply development projects which involve liquefied natural gas.

Mr. Bergsieker has 26 years of experience in the oil and gas industry, with over 19 years devoted to LNG. His experience includes LNG project development, marketing and operations, upstream production engineering /operations, marine transportation and logistics, joint venture relations and corporate/strategic planning.



Mr. Bergsieker began his career as a production engineer for Exxon, and was subsequently employed by El Paso LNG Company, Roy M. Huffington Company (Huffco) and Virginia Indonesia Company (VICO) before joining Enron International. During his 14 years at Huffco/VICO, he had executive level responsibility for the development and operation, on behalf of an international joint venture, of the Bontang LNG project in Indonesia.

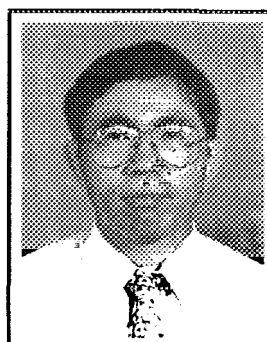
Mr. Bergsieker received a Bachelor of Science degree in chemical engineering from University of Missouri at Rolla in 1969 and an MBA from University of Missouri in 1972.



Ichizo Aoki & Yoshitsugi Kikkawa

LNG Plant Combined with Power Plant

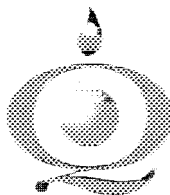
Ichizo Aoki is a Director of Chiyoda Corporation since 1989 and Senior General Manager of IT Center since 1995. He holds a B.Sc. in Applied Chemistry from Tohoku University. He joined Chiyoda as process engineer in 1961, and has worked in various capabilities since then, including technical advisor for Das Island Train - 3 Expansion Project, Qatargas LNG Project and Ras Laffan LNG FEED. Mr. Aoki is also a Director of the Society of Chemical Engineers in Japan.



Yoshitsugi Kikkawa is Engineering Consultant of Design and Engineering Division I of Chiyoda Corporation. He joined Chiyoda upon graduating with a B.Sc. in Fuel Chemistry from Akita University in 1965. He has long experience in basic/detailed design of LNG plants. He has been the Lead Process Engineer for Arun Train 4/5 expansion, ADGAS 3rd Train LNG and Qatargas LNG, Process Engineering Director for Ras Laffan LNG FEED, and LNG Technology Specialist for Trinidad LNG FEED.

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Jerry R. Schuyler

Chairman of Session (7) : Natural Gas Demand in Emerging Markets

Jerry R. Schuyler is Vice President of ARCO International Oil & Gas Company (AIOGC) and the Managing Director for ARCO Middle East, based in Dubai, UAE since January of 1996.



Mr. Schuyler joined ARCO in 1977 as a junior engineer in Alaska, and has since held positions of increasing responsibility in operations and planning in several ARCO divisions, including Manager of Prudhoe Bay Operations at ARCO Alaska, Inc., Anchorage, in 1993 and Manager of Upstream Corporate Planning at ARCO headquarters in Los Angeles in 1994.

Mr. Schuyler holds a BS degree in Petroleum Engineering from Montana College of Mineral Science & Technology.

Dr. Abdulrahman Ahmed Al-Jafary

The GCC Gas Pipeline

Dr. Abdulrahman Al-Jafary is a member of Majlis Al-Shura of the Kingdom of Saudi Arabia, and Secretary General of the Gulf Organization for Industrial Consulting (GOIC), Doha, Qatar. Before that, Dr. Al-Jafary was Professor of Management and Head of the MBA program, and also Dean of the College of Industrial Management at King Fahd University for Petroleum and Minerals (KFUPM), Dhahran, Saudi Arabia.

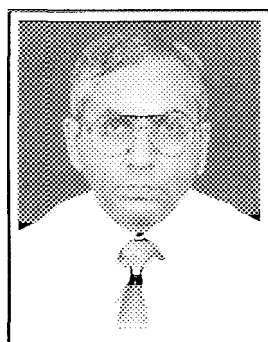


Dr. Al-Jafary received his B.Sc. in Geology from University of Washington, M.Sc. in Educational Administration from East Texas State University, and Ph.D. in Business Administration from University of Oklahoma. He has published numerous articles and papers dealing with management and industry issues, and participated, as speaker and panelist, in many Arab and International seminars and conferences.

R. P. Sharma

Prospect for Middle East Gas in India

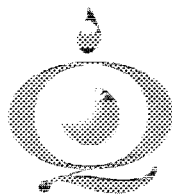
R. P. Sharma is Executive Director (Marketing & Planning) and Director (Projects) in Gas Authority of India Limited; he is responsible for developing optimal natural gas utilization in the country and for planning and developing the infrastructure needed for gas business.



Mr. Sharma has more than 33 years of experience in the oil and natural gas industry in India in the field of production, treatment, processing and marketing of oil and gas. He is Member of the Indian Team for import of Natural Gas to the Indian market, and Member Secretary of IGU Indian Chapter. He had number of papers presented in International Conferences.

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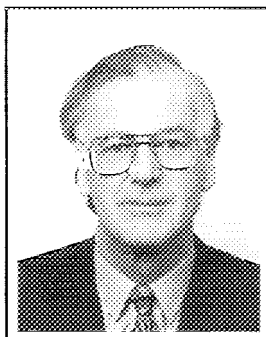
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Chaicharearn Atibaedya **Natural Gas Demand in Thailand**

Chaicharearn Atibaedya is Assistant Governor, Information Technology Center at Petroleum Authority of Thailand and Senior Vice President, Engineering & Planning, at Thai LNG Power Corporation Limited. Prior to that, he was Director, Business Development Department and Vice President, Business Planning & Information System. He has long experience working in the area of natural gas, downstream oil, and petroleum business.

Mr. Atibaedya holds a Bachelor Degree in Electrical Engineering, a Bachelor Degree in Mechanical Engineering, and an MBA.



Edward Thomas Walshe **Natural Gas Demand in Emerging Markets**

Dr. Edward Thomas Walshe is British Gas' Regional Managing Director for CIS, Middle East and Africa since December 1994. His previous position was Commercial Director in the Exploration and Production unit. A significant responsibility has been the development of the Karachaganak Project in Western Kazakhstan where Agip/British Gas and Gazprom will be partners in the Field. Prior to joining British Gas, he worked with BP in a variety of capacities, starting in the Research Centre at Sunbury, Middlesex and ending in Hong Kong with responsibility for BP Chemicals' activities in the Asia-Pacific region. He worked in BP's E&P unit on North Sea Gas and on various LNG projects with BP South-East Asia in Singapore on business development for all aspects of BP's business; with Deutsche BP in Hamburg on oil refining and marketing; and in a variety of oil business roles in BP's corporate Centre in London.

Dr. Walshe was educated in Dublin, obtaining a Ph.D in Solid State Chemistry from the University of Dublin. He attended the Harvard Advanced Management Programme in Spring 1990.

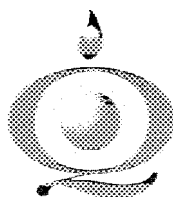


Abdul Razzaq Al-Siddiqi **Chairman of Session (8) : The LNG Chain : Technological Innovations and Cost Reduction**

Abdul Razzaq Al-Siddiqi is Technical Director at Qatar General Petroleum Corporation (QGPC) since 1994. His professional career began as Project Engineer with QGPC, and subsequently held a number of positions both within QGPC as well as its subsidiaries : Managing Director of Qatar Europe LNG Company, Project Director for the Ras Laffan Port and Infrastructure Development Project, Project Manager for Qatargas LNG Company, Engineering Manager, Construction Manager for Phase I of the North Field Development Project and Senior Design Engineer for Shell Expro U.H. He is a director of Qatar Fertilizer Company (QAFCO) and Qatar Clean Energy Company (QAFAC).

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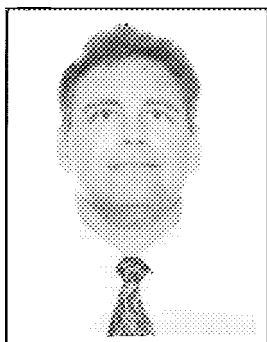


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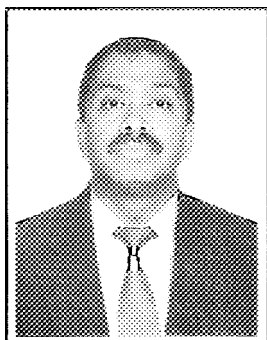
Mr. Al-Siddiqi holds a Bachelor of Science in General Science from Portland State University and a Bachelor of Science in Industrial Engineering from the University of Portland.



L. C. (Fritz) Frusen, III

Reducing Capital and Operating Costs in Gas Processing, Liquefaction, and Storage

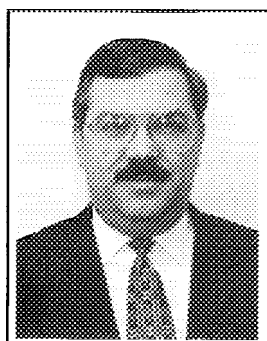
L. C. (Fritz) Frusen, III is the Manager of Upstream Process Engineering for Phillips Petroleum Company. He started with Phillips in 1978 after receiving his Bachelor of Science degree in Electrical Engineering from the University of Kansas. He has held numerous production, process, and project engineering assignments at Phillips, both domestic and foreign, including six years as the head engineer at the Kenai, Alaska, LNG Plant.



Ram R. Tarakad & Brian C. Price

The PRICO Cycle, The Low Cost Alternative to LNG Production

Dr. Ram R. Tarakad is Business Director for LNG and natural gas at Brown & Root Engineering and Construction. He has earned advanced degrees in Chemical Engineering, including a Ph.D. from the Pennsylvania State University. His industry experience includes twenty years in the Engineering and Construction business, primarily focusing on gas processing and LNG. He had been associated with LNG liquefaction projects in Algeria, Australia and Malaysia and LNG regasification projects both within the US and outside. Prior to assuming his present responsibilities at Brown & Root, Dr. Tarakad's experience covered process engineering and development, training, startup and engineering management.

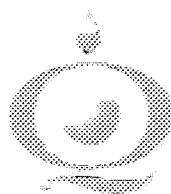


Brian C. Price is Technology Manager for Gas Processing and Cryogenics for the Pritchard Corporation, a subsidiary of Black & Veatch in Overland Park, KS, USA. He is in charge of technology development and process design for gas processing, NGL recovery and LNG production facilities for Pritchard. He has over 23 years experience in gas processing and related technology areas. Prior to joining Pritchard, he worked for ARCO Oil & Gas Co. in various positions including Manager of Process Engineering and Projects Manager.

Mr. Price is a member of AIChE and is active in the Gas Processors Association and API. He currently serves on the Editorial Review Board of the GPA and is past Chairman of the Technical Committee. He has BS and MS degrees in Chemical Engineering from Oklahoma State University.

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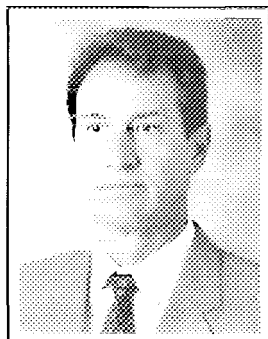
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LPA Davies

Conversion of Natural Gas into Liquid Fuels



Pat Davies is currently Group General Manager of Sasol Limited, responsible for Group Resources and globalisation planning, and is a director of several companies in the Sasol Group. He joined Sasol in 1975 and has held various positions in engineering design, project management, plant maintenance and operations management.

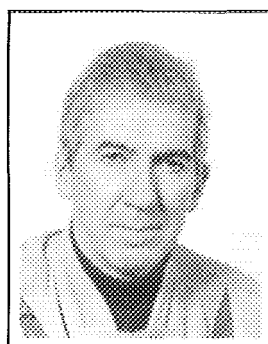
Mr. Davies obtained a Bsc degree in mechanical engineering from the University of Natal in 1975 and attended the Harvard Business School PMD in 1986.

Charles H.W. Peile & Richard G. Eddy

Reducing LNG Transportation Costs : Prospects and Challenges



Charles Peile joined Gotaas-Larsen in 1983 and was appointed Commercial Vice President in 1988. His commercial experience encompasses new business development in all the markets in which Gotaas-Larsen operates and involvement in the group's newbuilding programme for its crude oil tanker fleet. Since early 1993, he has concentrated his efforts on the group's LNG capabilities. He began his career in shipping in 1974 with a shipowner based in the North East of England. Since then he has worked in Madrid and New York, where he was President of a ship brokerage company, and more recently in London. He is a member of the Institute Chartered Shipbrokers.



Richard Eddy was Project Engineer during the 1950's on the world's first LNG carrier, "Methane Pioneer", and he has been active in the industry ever since. He joined Gotaas-Larsen in 1989 where his involvement is primarily in development of new LNG transportation business. Prior to joining Gotaas-Larsen, he was Director of LNG for Malaysia International Shipping Corporation where he was responsible for the construction and operation of the LNG fleet. During the 1960's, he was Project Engineer responsible for the design, construction and trials of the "Bridgestone Maru", the world's first low temperature LPG carrier. Mr. Eddy is also a founder director and past President of the Society of International Gas Tanker and Terminal Operators (SIGTTO). He holds a degree in Naval Architecture from Webb Institute, New York and an MBA from New York University.



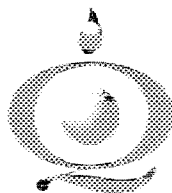
Dr. Mohammed Al-Sada

Chairman of Session (9) : Safety & Environmental Considerations in LNG Operations and Transportation

Dr. Mohammed Al-Sada is Corporate Manager of Safety, Quality & Environment, Qatar General Petroleum Corporation (QGPC). Prior to that, he had successively occupied various senior positions in the Corporation before he was appointed Head of Corrosion/Material

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Engineering in 1989, and Manager of Inspection, Safety and Environment Department in 1993.

Dr. Al-Sada is also Chairman of the Joint Energy/Environment GCC Task Force for Climate Change Framework Convention, Chairman of the National Committee on the Framework Convention on Climate Change (FCCC), Panel Member, State of Qatar Environment Protection Committee, and a member of many national and international associations. He holds a B.Sc. in Marine Science/Geology from Qatar University (1983), and a M.Sc. (Corrosion Science & Engineering) and a Ph.D. (Corrosion Science & Engineering) from the University of Manchester, United Kingdom.

Alain Vaudolon

Safety Aspects of the LNG Transportation Link

Alain Vaudolon was appointed General Manager of the Society of International Gas Tanker and Terminal Operators (SIGTTO) in July 1995, after a long career in gas shipping. He has been closely involved with the industry since 1969. His most recent experience has been the construction and operation of a series of LNG Carriers of 130,000 m³ for Petronas Tankers Sdn Bhd, a subsidiary of Petronas. Previously, after some years at sea finishing as chief engineer on a semi-pressurised LPG carrier at the end of the 60's, he held technical and operational posts in other LNG and LPG carrier fleets and was involved in the production of the IMO International Gas Carrier Code.



Abdulla Matter Al-Zaabi

Halon 1301 Replacement in ADGAS Installations

Abdulla Matter Ali Obaid Al-Zaabi is Deputy Head of Safety and Loss Prevention at ADGAS since April 1995. He joined ADGAS in 1994 as Senior Safety and Loss Prevention Engineer. Prior to that, he worked with ADNOC since 1985.

Mr. Al-Zaabi holds a B.Sc. in Industrial Engineering from the University of Toledo, Ohio (1985) and an Occupational, Health and Safety Certificate from Aston University, Birmingham (1989).



Rick Mire

Qatargas Crisis Preparedness

Rick Mire has been the Safety & Environment Manager for Qatar Liquefied Gas Company Limited since February 1994. He is a secondee of Mobil Oil Corporation and has 18 years of experience in Safety and Environmental protection. Mr. Mire holds BS and MS degrees in Engineering and Safety. He also holds credentials as a



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Professional Engineer, a Certified Safety Professional, a Certified Industrial Hygienist and a Diplomat of Environmental Engineering.

Takashi Yoneyama

Safety & Environmental Aspects in LNG Carrier Design



Takashi Yoneyama is a Project Manager in the ship design department of Mitsui Engineering & Shipbuilding Co., Ltd. He joined the company in 1972 in Tokyo head office. After the first contract of LNG carriers, he was shifted to Chiba shipyard to perform detail design of cryogenic systems. He has been involved in all LNGC projects in the company, i.e. Indonesian, Australian(NWS), Abu Dhabi, and Qatar LNG Projects. Since 1989, he is managing the whole design work as the Project Manager for LNGCs.

Mr. Yoneyama holds a B.Sc. in naval architecture from Tokyo University.

Tokinao Hojo

The Challenge for Safe Transportation of LNG



Tokinao Hojo is Director of Mitsui O.S.K. Lines since 1996, in charge of Liquefied Gas Carriers, Coal Carriers Division, and Tanker Division. He joined the company in 1966, after graduating with a Bachelor of Economics degree from Waseda University. Since then, he has worked in several capacities, and has been in charge to materialize nine MOL's LNG transportation projects during the period 1981-1994, including the Qatargas project.

Michel Halata

LNG Plant : Safety Considerations

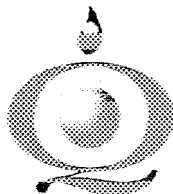


Michel Halata is a Senior Operations Advisor in Construction/ Operation Services for The M.W. Kellogg Company ; his primary responsibilities include the planning and execution of Initial Operations activities (Precommissioning / Commissioning / Start-up / Test Run) for projects worldwide, engineered and/or constructed out of the M.W. Kellogg Houston Operating Center. He has been with The M.W. Kellogg Company for six years, where he had both domestic and foreign assignments as a Commissioning / Operations Manager, primarily in LNG and ethylene plants. Prior to joining The M.W. Kellogg Company, he was an Operations Supervisor with ESSO Chemical Europe and a Technician with EXXON Chemical Americas.

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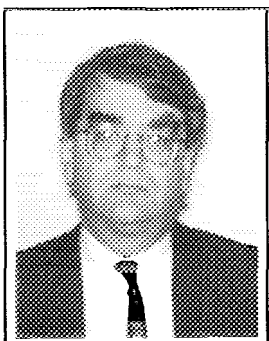


Dr. Hussain Al-Abdulla

Chairman of Session (10) : Economic and Financing Challenges

Dr. Hussain Al-Abdulla is Director of the Government Investment Office, Ministry of Finance, Economy & Commerce, where he oversees the management and evaluation of the Government of Qatar's Investment Fund in the international markets. He has also assumed outside responsibilities as the Vice-Chairman and Managing Director of the Doha Securities Market and as Project Finance Team Leader of QGPC.

Dr. Al-Abdulla received his Ph.D. in Economics from Bradford University in the United Kingdom.

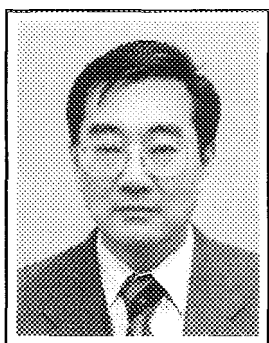


Daniel S. Lief

Financing LNG Projects - the Role of the Capital Markets Going Forward

Daniel S. Lief is Consultant, Structured Finance Group, at Goldman, Sachs & Co. Mr. Lief has spent his entire career at a member of the Investment Banking Division at Goldman Sachs. Most recently, he has been in charge of Goldman Sachs' structured finance, project finance and lease financing businesses in the Americas, Europe and Asia. He has worked with companies in all major industry groups and has played a major role in the development of many new and innovative financing techniques. In the energy sector, he has lead the effort of over \$3 billion of successful pipeline financings for major oil companies, provided advisory services and led the financing of over \$10 billion of power plants, and recently has headed the Goldman Sachs team on successful project financings for the Ocesa project (Colombian pipeline) and Ras Laffan LNG.

Mr. Lief received a J.D. from Boston University and a B.S. in Economics from the Wharton School, at the University of Pennsylvania.



Koichi Fujii

The Export-Import Bank of Japan and LNG Development Projects

Koichi Fujii is Director General, Project & Corporate Analysis Dept., J-EXIM, Japan.

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Jean O. Facon Financing LNG Projects

Jean O. Facon is a Managing Director of J. P. Morgan, in the Investment Banking division; he joined J. P. Morgan in 1979 in the Corporate Finance Department in Paris. He was transferred to London in 1984, where he has since occupied various positions in Capital Markets, Equities, M & A and Project Advisory. In that position, he was in particular responsible for overseeing J.P. Morgan's activities as Financial Advisor to the Qatargas Project.

Mr. Facon is a graduate of the University of Lyon (France) and received his MBA from Columbia University (New York) in 1977.

Dianne S. Rudo Financing LNG Projects



Ms. Rudo is the Vice President of the Project Finance Division at the Export-Import Bank of the United States. She joined Ex-Im Bank in June 1994 to head the development of a new division specializing in project finance. Since its inception in 1994, the division achieved final commitments for twenty transactions totalling approximately \$6 billion in U.S. Exports and almost \$20 billion in total project costs. Prior to joining Ex-Im Bank, she was the Director of Project Finance at Taylor-DeJongh, an international project financing advisory firm. At Taylor-DeJongh, she advised on project finance financings for infrastructure projects in Asia, Eastern Europe, the Near and Middle East. She has over twelve years of project finance experience.

Previously, Ms. Rudo was First Vice President in the Corporate Finance Department at Drexel Burnham Lambert, a Wall Street investment bank where she advised clients in the independent power sector on public and private security offerings as well as project finance and leveraged lease transactions.

Ms. Rudo received her MBA in Finance from New York University and her B.A. in Economics and French from Tufts University.

Craig Bennett Financing LNG Projects



Craig Bennett is Director of Project Finance for Societe Generale since January 1995, with global responsibility for this activity. He had education in geology, law and finance and has worked in each of those fields. Following the start of his working life in geology, he spent 6 years with EFIC in Australia before moving into the project finance and legal fields in Australia with Australian Resources

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Development Bank and Citibank, respectively. Since 1983, he has been with Societe Generale and, following a period of activity in the Capital Markets, he has been involved fully in project finance with the Bank since 1990. Some of the oil and gas projects in which he has been involved are Surat Basin development (Australia), Cooper Basin (Australia), North West Shelf gas and LNG (Australia), Rayong Refinery (Thailand), Qatargas LNG (Qatar), Qatargas Upstream (Qatar).

Ahmed Nabil

The Role of Regional Financial Institutions in Financing Future LNG Projects in the Gulf



Ahmed Nabil is a Senior Officer, Project & Trade Finance, in Arab Petroleum Investments Corporation (APICORP). He joined APICORP in 1990. His responsibilities encompass business development, marketing and credit assessment of APICORP's financing activities, particularly project finance, in a number of countries including Qatar, Saudi Arabia, Syria and Pakistan. He played active roles in structuring, negotiating and syndicating some of the major financings in the Gulf.

Mr. Nabil graduated as a Civil Engineer from Ein Shams University, Cairo; and holds a Master Degree in Project Management from Georgia Institute of Technology, USA.

Humbert de Wendel

Financing LNG Projects



Humbert de Wendel spent most of his career with TOTAL's Finance Directorate. He heads the Department in charge of financing Middle East projects and affiliates, as well as Power projects, since November 1996. He was previously in charge of Downstream (Refining and Marketing), took part in 1994-95 in the negotiation of the Qatargas project financing, and headed the Treasury Operations Department, responsible for the management of the centralised foreign exchange exposure and the short term funding and investments of the TOTAL Group.

Mr. de Wendel graduated from "Sciences Po" (Institute d'Etudes Politiques) and from ESSEC in Paris.



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Keynote Speech: Realities of the Gas Challenge

Sheikh Ahmed Zaki Yamani, Chairman, Centre for Global Energy Studies, U.K.

Middle East Gas : The Market Challenge

James Ball, Managing Partner, Gas Strategies, U.K.

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M. F. Chabrelie, General Secretary, Cedigaz, France

Paper No. (2-2): Middle East Gas : Utilization, Development, and Policies

Dr. Robert Mabro, Director, Oxford Institute for Energy Studies, U.K.

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Nasser K. Jaidah, Director, Exploration & Development of New Ventures, Qatar General Petroleum Corporation, Qatar.

Paper No. (3-2): Development & Implementation of the Qatargas Project Abdul Redha Abdul Rahman, General Manager, Qatar Liquefied Gas Company Limited, Qatar.

Paper No. (3-3): The Ras Laffan LNG Company : The Commitment of Today, The Challenge of Tomorrow
Neil Kelly, Managing Director, Ras Laffan Liquefied Natural Gas Company, Qatar.

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Natural Gas Demand in the Far East -
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CO-CHAIRMAN: Pierre-Rene Bauquis, Advisor to the President, TOTAL, France.

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Yuzuru Aoki, Representative Managing Director, Tohoku Electric Power Co., Inc., Japan.

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Sjahrial Daud, Director of Foreign Marketing, Pertamina, Indonesia

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H. C. Chang, Vice President, Chinese Petroleum Company, Taiwan

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CHAIRMAN: Pierre-Rene Bauquis, Special Advisor to the
President, TOTAL, France

CO-CHAIRMAN: R. D. Nelson, Vice President of LNG
Venture Development,, Mobil LNG Inc., U.S.A.

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Michael Tusiani, Chairman and Chief Executive Officer, Poten & Partners, U.S.A.

Paper No. (5-2): The Future of Middle Eastern Gas in Europe

Domenico Dispenza, Director Gas Supply, SNAM, Italy

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Mourad Preure, Sonatrach, Algeria

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Nikolyl I. Belyi, Director, Gazprom, Moscow

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Nuran Satana / Serpil Soylo, BOTAS, Turkey

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Dr. Naji Abi-Aad, OME Senior Consultant, Observatoire Mediterranéen de L'Energie,
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R. F. Guerrant, President, Mobil Power Inc., U.S.A.

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Richard P. (Rick) Bergsieker, Managing Director, Enron Development Corporation, U.S.A.

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Ichizo Aoki & Yoshitsugi Kikkawa, Chiyoda Corporation, Japan

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H.E. Dr. Abdul Rahman Al-Jafari, Secretary General, Gulf Organization for Industrial Consulting, Qatar

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R. P. Sharma, Executive Director (MKTG & PLNG), Gas Authority of India, India

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Edward Walshe, Managing Director, Special Projects - Exploration and Production, British Gas, U.K.



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Qatar General Petroleum Corporation, Qatar

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12th. C. "Fritz: Krusen, Principal Engineer, Global Gas Group, Philips Petroleum,
U.S.A.

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Ram R. Tarakad, Brown & Root Engineering & Construction, & Brian C. Price. The
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Paper No. (8-3): Conversion of Natural Gas into Liquid Fuels
LPA Davies, Group General Manager, Sasol Limited, South Africa

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Charles H. W. Peile, Commercial Vice President, & Richard G. Eddy, Gotaas Larsen, U.K.

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Safety & Environmental Considerations in LNG Operations and Transportation

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Quality & Environment, Qatar General Petroleum
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Alain Vaudolon, General Manager, Sigtto, U.K.

Paper No. (9-2): Halon 1301 Replacement in ADGAS Installations
Abdullah Mattar Al-Zaabi, Deputy Head of Safety & Loss Prevention, Abu Dhabi Gas
Liquefaction Company Ltd., U.A.E.



Paper No. (9-3): Qatargas Crisis Preparedness

Rick Mire, Safety & Environment Manager, Qatar Liquefied Gas Company, Qatar

Paper No. (9-4): Safety & Environmental Aspects in LNG Carrier Design

**Takashi Yoneyama, Project Manager-Ship Basic Design Department
Mitsui Engineering & Shipbuilding, Japan**

Paper No. (9-5): The Challenge for Safe Transportation of LNG

T. Hojo, Director, Mitsui O.S.K Lines Ltd., Japan

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Michel Halata, Plant Operation Manager, The M. W. Kellogg Company, U.S.A.

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**CHAIRMAN: Dr. Hussain Al-Abdulla, Project Finance Team
Leader, Qatar General Petroleum Corporation, Qatar**

**Paper No. (10-1): Financing LNG Projects - the Role of the Capital Markets Going
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**Daniel S. Lief , Vice President-Investment Banking Division, Goldman Sacs &
Company, U.S.A.**

Paper No. (10-2) The Export-Import Bank of Japan and LNG Development Projects

**Mr. Koichi Fujii, Director General- Projects & Corporate Analysis Department, The
Export-Import Bank of Japan, Japan**

Paper No. (10-3): Financing LNG Projects

Jean O. Facon, Managing Director, JP Morgan, U.K.

Paper No. (10-4): Financing LNG Projects

Dianne S. Rudo, Vice President, US EXIM, U.S.A.

Paper No. (10-5): Financing LNG Projects

Craig Bennett, Director - Project Finance, Societie Generale, France

**Paper No. (10-6): The Role of Regional Financial Institutions in Financing Future LNG
Projects in the Gulf**

Ahmed Nabil, Senior Officer-Project & Trade Finance, Apicorp, Saudi Arabia

Paper No. (10-7): Financing LNG Projects

Humbert de Wendel, Head of Department-Finance Division, TOTAL, France

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“Middle East Gas : Prospects & Challenges”

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The Gas Challenge

CHAIRMAN

H.E. Abdullah Bin Hamad Al-Attiyah
Minister of Energy and Industry
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Session (1)

The Gas Challenge

Congratulatory Message

B. Kino

Managing Director, Chubu Electric Power Co., Inc.

JAPAN

CONGRATULATORY MESSAGE

**Mr. B. Kino, Managing Director,
Chubu Electric Power Company, Inc.**

The first vessel of the Qatar LNG project, the 'Al Zubarah' berthed safely January 10th 1997 at Kawagoe LNG terminal of the Chubu Electric Power. That moment is what the Chubu has been longing for. 1997 is the year when this century's last & largest LNG Project is commenced. I sincerely believe it is highly appropriate for the 2nd Doha Gas Conference to be held at this time at this place.

LNG market has remarkably developed by good corporation of sellers & buyers for these 25 years. Now that price competition among difference sort of energies is getting more and more serious, it seems to me for the continuous growth of LNG market we are to cope with some great assignments such as enhancement of economic aspect of LNG beyond its long established virtue of security and reliability of supply.

I sincerely wish the participants of the Conference ---- the Gas Professional, would develop progressive and active discussions to mark a significant step for new development of the gas industry toward the 21st century.

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The Gas Challenge

Keynote Speech

Realities of the Gas Challenge

Sheikh Ahmed Zaki Yamani
Chairman, Centre for Global Energy Studies,
U.K.

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Middle East Gas : The Market Challenge

James Ball

Managing Partner, Gas Strategies

U.K

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Middle East Gas Supply

CHAIRMAN

H.E. Yousef H. Kamal

Undersecretary,

Ministry of Finance, Economy and Trade,

STATE OF QATAR

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“Middle East Gas : Prospects & Challenges”

Session (2)

Middle East Gas Supply

Paper No. (2-1)

Middle East Gas Reserves, Development Plans, and Future Prospects

M. F. Chabrelie
General Secretary, Cedigaz,
FRANCE



“Middle East Gas : Prospects & Challenges”

Session (2)

Middle East Gas Supply

Paper No. (2-2)

Middle East Gas : Utilization, Development, and Policies

Dr. Robert Mabro

Director, Oxford Institute for Energy Studies

U.K.



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**MIDDLE EAST GAS: UTILIZATION, DEVELOPMENT
AND POLICIES**

**Robert Mabro
Director, Oxford Institute for Energy Studies**

1. Introduction

It is a great honour to be invited to address one of the most important gas conferences of the world which attracts such a distinguished and expert audience. This comes as no surprise. Qatar has a privileged place in the international gas industry because of huge resources and recent dynamic developments in the LNG sector. And Qatari hospitality does not have many equals. I would like to take this opportunity to thank the organizers, particularly HE Minister Abdulla al Attiyah and his team for both the invitation and the event.

This paper consists of three parts following the title of the topic assigned to me. The first part summarises the pattern of production, exports and consumption in the region, the second reviews recent developments and the third discusses policies.

The verbal presentation of the paper will focus mainly on the third part as it raises more substantial issues for discussion.

2. Gas in the Middle East. Patterns of Utilization.

The Middle East which is traditionally thought of as a dominant world region in terms of oil reserves is also extremely rich in natural gas resources. The economic development of Middle Eastern countries which was driven by oil revenues in the past thirty or forty years could get some further impetus in the decades to come from a rational and economically efficient exploitation of natural gas.

Taking the Middle East and North Africa as our geographical focus, we find that the following countries have proved natural gas reserves. These are ranked in descending order in Table 1.

Table 1. Proved Natural Gas Reserves by Country. End-1995. Trillion Cubic Metres.

	<u>Country</u>	<u>Reserves</u>
1.	Iran	21.0
2.	Qatar	7.1
3.	UAE	5.8
4.	Saudi Arabia	5.3
5.	Algeria	3.6
6.	Iraq	3.1
7.	Kuwait	1.5
8.	Libya	1.3
9.	Oman	0.7
10.	Egypt	0.6
11.	Yemen	0.4
12.	Bahrain	0.1
13.	(Other ME)	0.2

	Total	50.7

Source: BP

Table 1 identifies twelve Middle East countries in the Middle East/North Africa with significant gas reserves. To complete the picture Syria and Tunisia should be added to the list. The only Arab countries, therefore where gas has not been found yet are Jordan, Lebanon, Morocco, Palestine and the Sudan. The latter has undoubtedly hydrocarbon reserves which are awaiting exploration. Not surprisingly all the countries mentioned are oil-producing countries but all gas in the Middle East/North Africa is not in associated form. Non-associated gas is an important resource particularly in Qatar, Algeria and Iran.

The BP source from which data in Table 1 are taken estimates the world total at 139.7

billion cubic metres. The share of the Middle East/North Africa is therefore some 36 per cent of the world total proven reserves. It is worth noting that the largest natural reserves in the world, after the Russian federation whose natural endowment is gigantic (34.5 per cent of the world total) are in Iran, Qatar, the UAE and Saudi Arabia. The countries of our region thus occupy all places between second and fifth in the world ranking.

Natural gas production in the Middle East/North Africa represents a much smaller percentage of the world total than reserves. In 1995, world gas production was estimated at 2,119 billion cubic metres. The share of our region was therefore about 10 per cent compared with a reserves share of 36 per cent. The world reserves/production ratio in 1995 was about 66 years, the corresponding ratio for the Middle East/North Africa was 235 years. This clearly illustrates the well-known fact that the gas industry in our region is at a very early stage of development. But the pace of change has been rapid in the past two or three years with new projects either coming into production as in Qatar, or being implemented as in Qatar again, Oman, Egypt, the Yemen etc.

Table 2. Natural Gas Production by Country. 1995. Billion Cubic Metres.

	<u>Country</u>	<u>Production</u>
1.	Algeria	60.6
2.	Saudi Arabia	39.6
3.	Iran	35.3
4.	UAE	27.2
5.	Qatar	13.5
6.	Egypt	11.0
7.	Bahrain	6.7
8.	Libya	6.2
9.	Kuwait	6.0
10.	Oman	5.5
11.	Other Middle East	4.5

	Total	216.1

Source: BP

Some countries of the region export gas either by pipeline or through LNG chains. Algeria exports through two pipelines to Southern Europe and Oman has a small pipeline link to the UAE. As regards LNG, the current exporters are the UAE, Algeria, Libya and Qatar. In coming years Oman, the Yemen and Egypt will probably join the LNG exporting group. In 1995, LNG exports from the region were of the order of 27.0 billion cubic metres to which

pipeline exports of 19.4 billion cubic metres should be added to obtain the total exports figure (46.4 billion cubic metres). The share of gas exports in total production of the region was therefore 21 per cent in 1995.

Two comments are in order here. The first is that the export share for the region as a whole is slightly higher than the world average which stood at 18.3 per cent in 1995. The second point is that, until 1995, this above-average export share was due to the significant place occupied by Algeria in world gas trade. It was not representative of the region as a whole. In fact Algeria exported then some 62 per cent of its production while the export share of the Gulf countries (the six GCC member states) was a mere 7 per cent. This pattern began to change recently with the first LNG exports from Qatar and will change further in the coming years as new projects in Qatar and Oman come on stream. Nevertheless, exports remain a critical issue of gas development in the region, particularly in the Gulf and the Arabian Peninsula.

Table 3. Natural Gas Production by Country. Middle East and North Africa. 1995. Billion Cubic Metres.

	<u>Country</u>	<u>Consumption</u>
1.	Saudi Arabia	40.34
2.	Iran	35.00
3.	UAE	23.60
4.	Algeria	20.62
5.	Qatar	13.60
6.	Egypt	12.43
7.	Bahrain	6.49
8.	Kuwait	5.97
9.	Libya	4.85
10.	Syria	4.79
11.	Oman	4.59
12.	Iraq	3.15
13.	Tunisia	1.82
14.	Jordan	0.30
15.	Morocco	0.02

Source: Cedigas

The domestic consumption of gas in the countries of the Middle East and North Africa in 1995 is detailed in Table 3. Only three of the fifteen countries listed were gas exporters in 1995 (the UAE, Algeria and Libya). Until that year gas was a fuel for the domestic economy in most of the region and the pace of its development depended exclusively on the expansion of local markets for gas in the household/commercial sector, power generation, water desalination, oil refining and industry (which includes metal smelting, fertilizers and

a variety of petrochemicals. Non-marketed gas production which does not always appear in the statistics is also utilized in many oil-producing countries for re-injection in the oilfields. This is an important use of gas that serves two purposes: it conserves the resource and it increases recovery from reserves in oil production.

Table 4. Share of Natural Gas in Energy Consumption by Country. Middle East and North Africa. 1994. Per cent.

	<u>Country</u>	<u>Gas Share</u>
1.	Qatar	88
2.	Bahrain	87
3.	UAE	59
4.	Algeria	59
5.	Oman	59
6.	Kuwait	54
7.	Libya	46
8.	Saudi Arabia	35
9.	Iran	33
10.	Egypt	29
11.	Tunisia	21
12.	Iraq	17
13.	Syria	15
14.	Morocco	0.2
15.	Yemen, Sudan, Lebanon	0

Sources: OAPEC for Arab Countries; BP for Iran

The share of natural gas in energy consumption in some Middle Eastern/North African countries in 1994 is shown in Table 4. In two countries of the region (Qatar and Bahrain) the shares of gas in total primary use are the highest in the world. In four other countries (the UAE, Algeria, Oman and Kuwait) the shares are higher than in any country outside the region other than Uzbekistan. This group of six countries with very high degree of gas penetration in the national energy market includes five GCC member states (that is all of them except Saudi Arabia) in the East, and Algeria at the other end of the regional map. For the purpose of comparison, note that the highest shares of gas consumption in primary energy use are shown in Table 5. In the USA, the largest gas consumer in the world (more than 620 bcm at present), the share of gas in total primary energy use is about 26 per cent.

Of course, the very large share of gas in energy use in the six countries of our region does not necessarily mean that the volume of gas consumed is very big. There are considerable variations among the countries of the region - as there are indeed among the countries of the world - in the levels of natural gas consumption. And these variations are not well correlated with either GDP, population size or the gas share in energy use.

Table 5. Share of Natural Gas in Energy Consumption by Country. Rest of the World. 1994. Per cent.

<u>Country</u>	<u>Gas Share</u>
1. Uzbekistan	79
2. Venezuela	51
3. Russian Federation	50
4. Argentina	46
5. Holland	42

Source: BP

Saudi Arabia where the volume of gas consumed is the largest in the region (but not the share in energy use) was the tenth biggest gas consumer in the world in 1995. In that year both Saudi Arabia and Iran each used more natural gas than some large oil-producing countries of the developing world (Mexico, Venezuela, Indonesia), more than a large European gas producer (Netherlands) and more than any other West European country with the exception of Germany, the UK and Italy.

Table 6. Gas Use by Sector. Middle East. 1994. Per cent.

1.	Gas use in the energy sector (upstream production of oil and gas, separation, processing, transportation and refining)	29%
2.	Gas use in power generation and water desalination	30%
3.	Gas use in industry (metals, fertilizers, petro-chemicals)	35%
4.	Gas use by households, commercial and other institutions, services, etc.	6%
Total		100%

Source: Abi Aad

Unfortunately there are no detailed statistics on the sectoral distribution of gas use for all the countries of the region. The broad sectoral structure for the Middle East (defined here as including Egypt but excluding all North African countries to its west) is estimated as shown in Table 6 by Naji Abi-Aad in *Natural Gas in the Middle East: Actual Status and Future Prospects* (OME, 1996).

The sectoral breakdown of gas use for those countries with available data is shown in Table 7. In Bahrain the energy sector use of gas in refining and in Saudi Arabia in the oilfields operated by Saudi Aramco. In Bahrain the aluminium complex (Alba) is a major gas user. Qatar has metal production (sponge iron, steel, reinforcement iron bars), fertilizers (ammonia and urea), petrochemicals (ethylene and polyethylene), cement and other industries all of which use gas as a fuel. In Saudi Arabia, besides the utilities (power and water) which take the lion's share of gas there is a very significant petrochemical industry. In all Middle Eastern countries gas utilization by households, commercial and other institutions (schools, hospitals etc.) and the services is still insignificantly small.

Table 7. Sectoral Composition of Gas Consumption by Country. 1994. Per Cent

	<u>Power and Desalination</u>	<u>Metals</u>	<u>Petrochemicals</u>	<u>Energy</u>	<u>Total Industry</u>	<u>Domestic Sector</u>
Bahrain	36%	33%	16%	15%	64%	
Egypt	65%				34%	1%
Iran	37%				61%	2%
Oman	most					
Qatar	@ 50%				@ 50%	
Saudi Arabia	60%		25%	15%	40%	
Syria	40%		20%	n.a.	n.a.	n.a.

Source: Abi Aad

To sum up. The Middle East (including North Africa) is a very rich gas region of the world where the development of production and trade is still at a very early stage. The resource is there awaiting for market opportunities both at home and abroad. Gas consumption is not insignificant in five or six countries of the region but much expansion remains possible. In the GCC gas has captured certain sectors such as utilities and heavy industry. It has penetrated the power sector in Egypt and its uses is very diversified in Algeria. Direct gas use in the household/tertiary sector is very small but much is used in this area indirectly through the transformation of gas into electricity. In short the physical potential of gas in the region is considerable but the economic potential is more varied and much more difficult to assess.

2. Gas Developments in the Middle East.

The development of gas reserves is fairly recent in the Middle East. Until twenty years ago, that is until 1976-7, associated gas was utilized on a very small scale in a few countries. Most of associated gas was still being flared. Non-associated gas saw some earlier developments in Algeria which began to export LNG in 1964 and in Iran which exported pipeline gas through IGATT-I to the Soviet Union for a very short period in the mid-1970s.

The first export project from the Gulf region was Abu Dhabi's. LNG exports to TEPCO in Japan began in 1977. Remarkably this remained the only source of gas exports from the Gulf for almost twenty years that is until Qatar Gas began shipments to Japan.

The situation has changed in the 1990s with a strong revival of interest in gas projects. On the LNG front Qatar has entered the exporter club and will be soon followed by Oman and the Yemen. In the Mediterranean, Algeria has a new pipeline outlet to Spain via Morocco; Libya and Agip are interested in an export project to Italy and Egypt where large offshore reserves were recently found near Ras el Barr is examining possible export projects to Turkey with AMOCO favouring an LNG chain and AGIP a pipeline.

The breakdown of the Soviet Union has created interest in the gas resources of Central Asia. One of the development problems there is political because of superpower's strong opposition or preference (the USA on the one hand and Russia on the other) for particular routes. To the extent that Central Asian gas involves Iran (there is already a line between Turkestan and Iran) and Turkey, there are implications for the Gulf and the Middle East.

Important gas developments have taken place in some countries - Saudi Arabia, Iran, Abu Dhabi, Egypt etc. for the purposes of injection in oilfields, production for the domestic market, or for condensates.

But the complex problems relate to export projects. The ratio of projects that are talked about over the years to those that are implemented is high. What has happened in recent years is a significant increase in 'project talk' and some realizations and these features of the scene are encouraging. There is a change considering that nothing much had happened between the mid-1970s and the early 1990s.

The problems of export development are familiar. The first one is to find a suitable buyer; the second is to agree on pricing; the third is to sort out the financing; the fourth, which arises in some cases, is to solve political difficulties which may occur in routing pipelines; and the fifth is to agree with partners the terms of the upstream development. Very long and painstaking negotiations have to take place and it is not always possible to remove the multitude of obstacles.

Gas export arrangements are infinitely more rigid than most international trade contracts. This is inevitable at present and will remain so until such time when international gas trade would become so extensive and so diversified as to make the commodity similar to any other in the world market. For the moment the producer needs the security of a buyer. And the buyer cannot take long-term commitments unless he has control over its own market. We are in a world where everybody wants to liberalize everything. Those who wish to apply

these policies to gas on the grounds that it will help gas may be right in their approach in some special cases. They are likely however to kill gas trade prospects in many other places in the world.

3. Policies

The fundamental principle of development policy is to invest scarce funds where the returns are greatest. The difficulty which is immediately encountered when applying this principle is that the investment costs are incurred at the beginning of a project and the returns accrue after a time lag and are spread over a period of time stretching ahead in the future. There is a difficulty, first because the future is uncertain, and secondly because costs and benefits arising at different dates may not be valued identically by the investor.

(i) Certainties and Uncertainties

There is not much we can do about uncertainty. The recourse to forecasting models is widespread but forecasts should never be used as predictors of future events. They are devices which tell us that Y will result if assumptions X do obtain. The value of the forecast is in the logic which lead from the assumptions to the result. Unfortunately very few people use them in this way. An alternative to forecasting is scenario planning. The design of meaningful scenarios is a more subtle and complex exercise. But in the end, scenarios and forecasts are nothing but instruments whose aim is to assist in thinking about the future. One can reduce the range of uncertainties through imaginative and methodical reflection about possible trends and accidents; and this is useful. But a residual uncertainty will always remain.

When considering a natural gas investment one can rely however on a number of fairly safe certainties. These are:

- (1) Gas has clear environmental advantages over coal, lignite, orimulsion and oil.
- (2) Gas is a newcomer in energy markets relative to coal and to its part-successor oil. There is therefore some possibility of substitution: the new fuel, gas, replacing in certain uses the older fuels.
- (3) Gas has superior combustion characteristics than either coal or oil. The flame is pure and can be directed with great ease to the point of application.
- (4) Gas transport is costly. The major gas reserves (FSU, Iran, the Gulf) are at a great distance from the regions where demand is significant (USA, Europe, Far East). This puts gas at a very significant economic disadvantage vis-a-vis other fossil fuels. Put differently the netback that may be realized from exporting one BTU or a barrel of oil equivalent of gas is likely to be, and to remain for years to come, a fraction of the netback realisable from an equivalent unit of oil exports.
- (5) Gas as a natural resource is abundant. There is no problem of geophysical shortage in the foreseeable future.
- (6) Gas, though more versatile in its uses than coal, is significantly less versatile than oil. This limits the range of sectors in which gas can displace oil with relative ease. Take the transport sector for example. It is possible to run cars on gas (CNG or LPG) or on gas-derived products (methanol). But the use of these fuels is either more clumsy (heavy CNG tanks in the back of the vehicle) or less environmentally friendly

(methanol is not a 'nice' fuel).

(7) Gas is toxic and explosive. A serious accident at an LNG terminal or an LNG carrier could seriously affect the development prospects of gas in the same way as the prospects for nuclear suffered worldwide following both actual accidents and the fear of accidents.

But this latter point brings us to uncertainties with which inevitably the investor has to cope. The most important are:

- (1) The future occurrence of accidents and their implications are unknown.
- (2) The trends of energy prices in the long run (and this is important because gas projects have very long maturity) are very uncertain.
- (3) The nature and rate of technological innovations which may either advantage gas (e.g. an innovation that lowers the building costs of an LNG carrier) or that disadvantage it (the discovery of a superior fuel) are likely to involve surprises.

(ii) Time Preference and Rates of Discount

The problem of time preferences - or put in other words, the problem of how to compare costs and benefits obtaining at different dates - deserves some attention when it arises for gas development in the countries of our region. In principle the issue of valuing future income streams is pretty straightforward. The principle is that of present values. Future income streams are discounted to the present by a rate which represents the opportunity cost of money. And the rationale is simple: if I have £100 this year and my best investment opportunity is a deposit with 7 per cent annual return, then £107 next year is the equivalent of £100 today. But can we apply the same logic for gas development in a Gulf country? The answer would be 'yes' if capital markets were perfect and if the temptation to waste revenues did not exist. The hydrocarbon exporting countries of the Middle East may be in greater need of revenues in the future than today. This could be due to two reasons: (a) limitation on the country's ability to absorb productive investments in the short run and (b) increasing needs in the future frustrated by the early depletion of the natural resource (usually oil but now, in many places, the same issue arises for gas).

A conventional economist will probably stop us at this point and say: so what? He or she would argue that one should invest available funds in projects according to optimal rate of returns rules and not worry if too much revenue is generated when it is not needed for current consumption and profitable investment in the economy, and too little is generated later by the same project when expenditure needs have increased. The surplus revenues of today can be placed in portfolios abroad if the absorptive capacity of the country limits further domestic investments. They will generate an income over the years and thus supplement future oil revenues.

In fact he or she would go further arguing that the present value of a natural resource with a physical life of, say, twenty five years is close to zero. There is no point delaying development on depletion grounds if exhaustibility is unlikely to bite this number of years.

The only valid criterion for an investment in the development of a natural resource, in this case, is the present value of the income stream or the rate of return as assessed today.

In an ideal world the conventional economist would be perfectly right. But our real world is far from being ideal. Governments cannot be trusted to save enough for future generations even when they are awash with revenues. Demands for immediate expenditures and distribution of revenues to this or that project (however uneconomic) or to this or that interest, which emerge in all places and all circumstances, increase in intensity when there is an income windfall or significant revenue growth. What governments manage to save becomes the object of greed either from other countries or from dishonest individuals. The savings would be targeted by superpowers for the purchase of weapons, or by a neighbour engaged in an ill-prepared and unnecessary and devastating war with another neighbour, or by indiscrete officials in charge of portfolios.

Further, income streams with different time patterns are not fully substitutable through the equivalence brought about by rates of interest (or rates of discount) simply because capital markets are not perfect.

In short our argument is that two sets of considerations should be brought to bear when deciding on oil or gas projects. The first set includes the usual rate of return computations and comparisons with alternative projects. The second relates to the timing of revenue streams that the projects will generate. Countries with relatively small populations and a paucity of resources other than hydrocarbons should not want to get too much future revenue all in advance. The need for revenue is greater in the future than in the present because population growth is high and because the time horizon of economic development is very long indeed in most oil/gas exporting countries. And paradoxically the revenue that accrued now may be at a discount to the same revenue accruing later if meanwhile the portion put aside is badly invested (white elephant projects at home), looted or spent after a relatively short period as a result of the 'liquidity effect' (cash in the pocket tends to burn it and be spent earlier than planned).

It is important to emphasize again and again that economic development in the case of a hydrocarbon economy means (a) the creation of a complementary and self sustained income-generating sector than oil or gas and (b) huge effective investments in human capital (it is not just a matter of how much is spent on education and skill formation but on the quality of this education), and that both these endeavours are very, but very long affairs. Almost twenty-five years after the oil price revolution of 1973 one cannot find an oil-exporting country that has established an alternative economic base to oil that can sustain development. No oil-exporting country has achieved in these twenty-five years sufficient progress on the human capital front that would enable it to cope with the technological and organizational challenges of the modern world. The development horizon for these countries may well be as long as seventy or eighty years, perhaps as long as a century. The depletion policy should take this fact into account while giving due weight to uncertainties about the economic life of fossil fuels that may be cut short by technical innovations.

(iii) Gas Development Policies

Let us turn now to some basic but important propositions about gas development

policies.

- Go back to the fact that the netback per BTU or per ton of oil equivalent in any other measure is much lower for gas than oil exports particularly if the destination is at a great distance from the exporting country. It follows that the first gas policy in an oil-producing country is to ensure full penetration of gas in the domestic market. The aim is to maximize oil exports in the first place by releasing as far as possible amounts that are consumed domestically. This is particularly important in countries like Iran and Egypt where both oil and gas is available and where domestic energy consumption has tended to grow at a fast rate. In Iran the growth of domestic oil consumption is very high and oil production is stagnant. The inevitable result is a continuing decline in the volume of oil exports. A policy to expand the local use of gas may turn out to be more beneficial to the Iranian economy, despite high direct investment costs, than the promotion of some gas export project. The benefits of the first policy include the indirect ones accruing from the exports of oil. This as such does not apply to Qatar. What is relevant however is the comparison of the investment returns on gas and oil development. If oil projects have higher returns than gas projects and the funds available are less than required for all the good oil projects then gas will have to be delayed. If funding sources exist for all projects the national oil corporation must seek to invest its share in both sectors in ways that equalise the returns of the dollar invested (which can never be achieved in an exact manner, only approximately). Of course the return must be at least as good as the opportunity cost of money.

- Investments in projects that transform gas into fertilizers or petrochemicals or use it as a fuel in smelting metals do not obey any different rule. Contrary to a widespread belief there are no significant externalities in heavy industry. They do not employ many people (this was seen as an advantage in the past because of underpopulation in the Gulf countries but is much less than an advantage now that the national labour force is expanding everywhere and employment problems are beginning to arise). They do not therefore impart skills to a large number of citizens. They can however throw some linkages and thus provide opportunities for investments in complementary industries. For example, metal smelting may encourage the development of manufacturing using the metal as input.

Taking this into account, investment in gas-intensive projects should be assessed on their economic merits as any other project. Where gas resources are abundant it is unlikely that these projects will compete at the margin with gas exports. If the gas reserves are abundant there is no case for conserving the resource for future industrialization. There will always be enough gas for that purpose. They should be undertaken (insofar as gas is concerned) so long as they can afford a price of gas equal to the highest netback possible in a gas project. Because this netback is usually low the economics of gas-intensive industries is boosted in the Gulf countries.

- A regional policy on gas must cope with the fact that all countries in the Gulf have gas resources albeit of different sizes. The objectives of the regional policy therefore must be twofold (a) to provide the rare country which may face a deficit with additional supplies (b) to improve where possible the geographical distribution of supplies in order to shorten export lines.

- Finally there is the complex export policy issue. The Gulf countries are far too distant

from Europe to make either LNG or pipeline exports to this large market economically attractive. Japan and Korea are at the outside limits of economic viability. The question as regards Europe is whether countries with large reserves like Qatar should attempt to gain a foothold at great immediate costs. The argument sometimes advanced is that the growth in European gas demand will be met by those who happen to be there. One needs therefore to 'invest' in acquiring a position in that market which will pre-empt competitors' investments in similar projects which they would undertake to capture the incremental demand for oil. To assess this policy one needs to apply the same criteria as for any investment and try to estimate the incremental demand for gas over the next twenty years, assess the policy of competitors and the costs of their own future projects, and evaluate the costs of a 'market share' policy. If the long run benefits appear to exceed costs then the 'put a foot in the gate' policy would be worth pursuing. The peculiar feature of this situation is that the producer who fails to enter first may not be able to enter later because of foreclosure by other producers. The Gulf countries who will need revenues in the long term from their hydrocarbon resources may have to apply unconventional investment criteria in this particular case.

In Asia particular attention should be given to the Indian sub-continent and Thailand as distances from Gulf export sources are shorter than in Korea and Japan. But there may be a trade-off between distance on the one hand and incremental demand and financing on the other. In some markets the packaging of a gas project with a power station in the importing country is the only way ahead.

Finally a word on contracting policies which are germane to the investment issue is in order. There has been much talk recently about the relevance of 'take or pay' clauses in gas contracts. Some argue that the experience of British Gas in the UK proves that these clauses can be disastrous for the buyer. Others point to the fact that large projects do not need 'take or pay' guarantees to be undertaken as shown by huge oil projects. And some believe that gas will soon become a very mobile commodity in international trade, with spot transactions and short-term contracts becoming significant and making 'take or pay' obsolete.

Our comments on these points are as follows. (a) A buyer can only honour take or pay when he has control of its market, that is so long as he has a monopoly. If the monopoly is threatened then take or pay is a very risky clause when it applies to small volumes. The weakening of the monopoly of utilities may adversely affect gas development. (b) Large gas projects need guaranteed sales, and are different from oil projects in this respect, because gas is still not perfectly mobile in international trade. The producer is still in need of a secure outlet. One should not jump the gun, here, and imagine that the trade in gas has become similar to the trading in oil because there is a small spot market in the UK.

4. Conclusions

The main conclusion is that natural gas still remains in a sense the fuel of the future. This means that the development of gas resources is essentially a matter of long-term strategy. If the time frame of investment were the short/medium term then investment in oil would win over gas in cases where exports involve shipments or pipeline transport over long distance.

A strategy for the long run may well entail the undertaking of projects which will give the producer a position in markets likely to expand in the future. But the pursuit of such a strategy requires financial resources and nerves.

In general the national market for gas, and markets in neighbouring countries, should have priority. In some countries of the region gas penetration is very extensive. It is then right to concentrate heavily on exports. But Qatar and Bahrain are exceptions in this respect.

The relationships between gas and liquid hydrocarbon fuels are interesting. Gas can be and is being used to boost oil production and recovery factors in oilfields. This is a proper use of gas. Gas displaces oil as a fuel in energy markets but yields a low netback. If all gas and oil producers formed a single cartel they will produce oil first and delay gas. But they are not. As a result the drive for gas harms oil and there is therefore an opportunity cost which gas producers who, in many instances, are also oil exporters, should consider. The economics of gas often depend on the condensates. In some instances gas is the economic by-product of condensates and not the other way round. Thus more gas means also more oil supplies in international markets.

Considering all these inter-relationships one wonders why oil-exporting countries do not discuss gas strategies among themselves at least for the purpose of clarifying their mind.

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الدوحة - قطر

“Middle East Gas : Prospects & Challenges”

Session (3)

Qatar's Gas

CHAIRMAN

Faisal M. Al-Suwaidi

Vice Chairman, Qatar Liquefied Gas Company Ltd.

QATAR



“Middle East Gas : Prospects & Challenges”

Session (3)

Qatar's Gas

Paper No. (3-1)

The Gas Industry In Qatar Options & Strategies

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THE GAS INDUSTRY IN QATAR **OPTIONS & STRATEGIES**

Possessing one of the largest gas fields in the world with definitive proven reserves, Qatar started its development of these reserves towards the end of the last decade. The overall situation of the gas market was unfavourable. The prices for energy were declining and the cost for development of both offshore field and transportation was almost prohibitive. Major international gas players were shy and very reluctant to invest or enter the gas market through the Qatar Road. Such ventures were considered to be too risky.

Qatar faced the challenge and the risk and decided to proceed in two directions. One to meet its ever climbing gas demand for domestic consumption to fulfill the requirements for both power as well as the downstream industries. On the second front, all efforts were exerted towards the export of gas that normally is represented by Qatargas.

During this period, skepticism prevailed as to whether such a project will eventually take place. Forecasters of the industries maintained the belief that more than US\$4 to US\$5 per Mmbtu is required if such a project is to be made profitable.

Since then interest in the development of exploration and local gas projects has multiplied, with major gas players and premier market buyers willing to participate by investing in further developments.

How has this been achieved? And, how is Qatar looking into the future? What are the options, strategies, and risk management policies that are being adopted?

In addition to the prospects of further local gas utilisation opportunities, how is Qatar planning to alleviate the challenges of penetrating the regional, European and emerging markets.

The objective of this presentation is to share with the conference participants answers to all those questions from Qatar's perspectives.



“Middle East Gas : Prospects & Challenges”

Session (3)

Qatar's Gas

Paper No. (3-2)

Development & Implementation of the Qatargas Project

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**DEVELOPMENT & IMPLEMENTATION OF
THE QATARGAS PROJECT**

by

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DEVELOPMENT AND IMPLEMENTATION **OF THE QATARGAS PROJECT**

1. INTRODUCTION

Qatar Liquefied Gas Company Ltd. (Qatargas) was established in 1984 by an Emiri Decree to build, own and operate a 6 Mtpa (million tonne per annum) LNG Plant (**Downstream Project**) in Qatar using North Field gas as feedstock, and to export the products. At the time, the joint venture partners with Qatar General Petroleum Corporation (QGPC) were TOTAL and British Petroleum (BP). Marubeni and Mitsui joined Qatargas in 1985 and 1989, respectively, BP withdrew in early 1992 and Mobil joined a year later. Today, and since January 31 1993, shareholders in the LNG Company are:

QGPC	65.0%
TOTAL S.A.	10.0%
Mobil Qatargas Inc.	10.0%
Mitsui & Co. Ltd	7.5%
Marubeni Corporation	7.5%

Qatargas shareholders and/or their affiliates are also carrying out North Field Upstream Development (**Upstream Project**) to provide feedgas requirements of the Qatargas LNG Plant. The Upstream Project is governed by a Development and Production Sharing Agreement (DPSA) executed between the Government of the State of Qatar and TOTAL in 1991. The DPSA was subsequently revised in January 1993 to include all Qatargas' shareholders:

QGPC	65.0%
TOTAL Qatar Oil & Gas S.A	20.0%
Mobil Qatargas Inc.	10.0%
Mitsui Gas Dev. Qatar B.V.	2.5%
MQL International Ltd.	2.5%

Qatargas is responsible for the implementation and operation of the Upstream Project.

The Qatargas Project has been the only grass-roots LNG development geared to the Japanese market in this decade.

- In May 1992, Qatargas concluded its first SPA (LNG Sales and Purchase Agreement) for 4 Mtpa with Chubu Electric Power Company for a period of 25 years starting January 1997 (1997 - 2021). The two-train/4-Mtpa Project has been completed and Qatargas started its LNG exports on schedule: Al Zubarah, carrying the first LNG cargo, left Ras Laffan Port in Qatar on December 23, 1996 and arrived at Kawagoe terminal in Nagoya (Japan) on January 10, 1997.
- In December 1994, Qatargas concluded its second SPA for 2 Mtpa (third LNG train) with a group of seven Japanese gas and utility companies, thereby raising capacity of the Project to 6 Mtpa. LNG exports under this SPA are due to commence in September 1998, and to continue till end 2021.

2. THE QATARGAS OVERALL PROJECT

2.1 Development Strategy

The overall LNG chain, i.e. Upstream, Plant and LNG Shipping, for the two-train/4-Mtpa Project has been designed to minimize preinvestment and the impact of adding a third LNG train for an additional 2 Mtpa:

- Downstream : the layout of the Plant has been configured to allow for 6 Mtpa of LNG and for an ultimate expansion to six LNG trains (12 or more Mtpa).
- Upstream : the offshore production gas pipeline and some of the onshore facilities are able to accommodate over 1400 Mscfd (million standard cubic feet per day) of production gas for the 6 Mtpa LNG Plant.
- Shipping : Qatargas will not own LNG carriers, but it has full responsibility for the transportation of LNG. The time chartered LNG fleet could be extended from seven to ten carriers when LNG production reaches 6 Mtpa.

2.2 Upstream Facilities (Figure 1)

The Phase II or Qatargas North Field Bravo Offshore Complex facilities (NF Bravo) are capable of an average nominal wellhead production of 900 Mscfd of gas sourced from the Khuff K4 reservoir of the North Gas Field to supply the feedstock requirements of the 4 Mtpa liquefaction plant. It is located approximately 80 km north-east of Ras Laffan and approximately 10 km south-east of QGPC's Phase I (NF Alpha) Platform Complex.

The 900 Mscfd offshore production centre consists of two wellhead platforms, a process/utilities platform, an accommodation platform, a flare platform, and connecting bridges with support platforms. The dehydrated gas and dewatered condensate are transported 80 km to the onshore reception facilities at Ras Laffan via a single 32-inch undersea pipeline operated in diphasic mode. Condensate for export (1.3 Mtpa) is extracted in the Upstream onshore facilities

Additional facilities to provide feedstock gas for the third LNG train onshore are in progress; these will raise the exported quantity of condensate to above 1.9 Mtpa.

2.3 LNG Plant (Figure 2)

The Qatargas LNG Plant facilities (and Upstream Onshore facilities) are located in the new industrial complex at Ras Laffan where QGPC has undertaken the financing and construction of an entirely new port - the Ras Laffan Port (RLP). Qatargas has the benefit of a dedicated berth for export of LNG and shared berths for condensate and sulphur.

The Qatargas LNG Plant is a modular project, initially based on two LNG process trains, storage and loading facilities and all offsite and utility systems required for production and shipment of 4 Mtpa of LNG. The LNG Plant is powered by gas turbines for process compression and electrical generation, and it is cooled by a once-through sea water system. Addition of a third LNG train, raising the annual LNG production to 6 mtpa, is in progress.

2.4 Shipping

The 4 Mtpa project requires a fleet of seven LNG carriers, each of 135,000 cubic metres nominal capacity, to transport annually 4 million tonnes of LNG from Qatar to Japan. Three further carriers are being built to transport the additional 2 Mtpa of LNG that will be available from the third train.

Shipment of condensate (until a planned condensate refinery comes onstream by end-2000) and sulphur will be arranged by the off-takers of the products.

3. DESCRIPTION & IMPLEMENTATION OF UPSTREAM FACILITIES

3.1 Contracting Strategy

The Project covers all facilities from the offshore production gas wells to downstream of the onshore feed stock gas separation facilities. Four separate competitively bid EPCC (engineering, procurement, construction and commissioning) contracts were awarded during the period December 1993 - March 1994. These were:

C-004 : Wellhead Platforms, Jackets, Flare, Bridges & Living Quarters Topsides (McDermott - ETPM)

C-005 : Process & Utilities Platform Topsides (NPCC - Technip Geoproduction)

C-007 : Onshore Facilities - gas reception, separation, condensate stabilization & storage/ship loading (Toyo Engineering)

C-008 : Production Gas Pipeline from NF Bravo Complex to shore at Ras Laffan (Saipem)

In addition, Qatargas undertook the procurement of all bare line-pipe for Contract C-008 and a small amount of line-pipe for Contract C-007.

All Upstream contracts were awarded on a lump sum basis, and Completion Packages were divided to facilitate handover during a phased period, with penalties assigned for late completions.

Overall coordination between contractors was undertaken by Qatargas. Resident Qatargas Project Task Forces were established in design offices and fabrication yards of contractors to facilitate rapid decision making and approvals for matters of direct concern to Qatargas.

3.2 Offshore Platform Complex

The conceptual and basic design work was undertaken in 1992-93, in offices specially set up for Qatargas in Technip's Paris Office. Various configurations of the Offshore Platform Complex were investigated, but the adopted arrangement is similar to QGPC's NF Alpha Complex.

The Qatargas NF Bravo Complex is therefore in the form of a cross, arranged with its "vertical" axis aligned on the prevailing wind of 330° to north, in a water depth of 53 metres. Looking downwind, there is firstly the Living Quarters Platform, followed by the Process & Utilities Platform then the Main and Intermediate Bridge Supports and finally the Flare Platform. On the "horizontal" axis there are Wellhead Platforms 1 and 2, whose flowline bridges connect to the Main Bridge Support.

To provide feedstock gas for LNG Train 3, a third Wellhead (WH) Platform is installed. This free-standing WH Platform is located South-East of the Bravo Complex, and will be connected by a single sub-sea trunkline (20 inches in diameter and about 6.4 km long) to an additional Process Platform which is to be installed at the Complex and be bridge-connected to the Process/Utilities (PU) Platform.

Wellhead Platforms 1 and 2 each have 9 well slots, with wellhead fluids being manifolded together before the flowlines are routed to the PU Platform. The Platforms were installed early (in January 1995) in order that drilling could commence by use of two jack-up rigs, "Hakuryu 8" and "Hakuryu 9". The planned number of wells is initially 15, each drilled to an average depth of 2900 metres and with an average deviation of 40° from vertical; WH-3 Platform will have 5 wells.

The process steps of the PU Platform include:

- wellhead fluid production and well testing
- initial separation of the gas, condensate and free water
- cooling of gas and condensate
- further separation of gas and condensate
- dehydration of gas and condensate
- comingling of gas and condensate for routing to shore.

Essentially, the offshore process equipment is divided into two trains, each of nominal capacity 484 Mscfd gas production, and with combined peak feedstock gas flow rating of 919 Mscfd to the LNG Plant. This peak feedstock gas flow will rise to 1378 Mscfd when the third train is completed.

The single production gas pipeline to shore also originates on the PU Platform before being routed to the sea bed on its way to Ras Laffan.

The Living Quarters (LQ) Platform has 36 bedrooms and maximum capacity of 98 beds. There is a medical centre, and the leisure facilities include a squash court, gymnasium, snooker table and TV lounge, supported by a good quality dining room. A helideck and passenger handling office is located at the uppermost level.

To support the offshore process trains and the living requirements of the resident operating staff, utilities equipment is provided on the PU and LQ platforms. These includes:

- power generation by gas turbine (PU Platform)
- potable water production by desalination (LQ Platform)
- fire fighting by sea water (PU Platform)
- treatment of process water and sewage (PU Platform)
- telecommunications equipment (LQ Platform).

For safety and abnormal operation purposes, any relief gas is directed to the Flare Platform where the gas is discharged at the top of a 95 metre tower. The bridges between the various platforms are used to carry the interconnecting flowlines, pipes and cables, in addition to providing personnel walkway access between the operating areas.

The detailed design, procurement, construction, installation and commissioning (where applicable) for all the platform jackets and the LQ Platform topsides were undertaken by McDermott/ETPM using their fabrication yard in Dubai. The similar scope for the PU Platform topsides was undertaken by TPG/NPCC using NPCC's fabrication yard in Abu Dhabi. Both contracts were awarded in December 1993.

The one piece LQ topsides module was skidded on to the transport barge in February 1996 for its journey to the North Field. It's weight was 2,100 tonnes. On location, the module was lifted into place on the piled four leg jacket by the McDermott crane barge DB27 during a night-time operation. Such action was necessary due to the unusually inclement weather conditions that were being forecast.

The single PU topsides integrated-deck module was also skidded on to a larger transport barge in January 1996 for its journey to the North Field, but on this occasion, with the module support legs sitting outside the sides of the barge. The module weight was 7,100 tonnes. On location in early March, the barge was carefully manoeuvred between the eight protruding legs of the piled jacket, and the module legs were lowered on to the jacket by using a combination of barge water ballasting and hydraulic jack retraction. The whole installation activity lasted about 12 hours and was blessed by favourable offshore weather, which was important due to the limited 0.3 metre clearance of the barge inside the jacket legs.

The main advantage of the one-piece modular fabrication for the topsides was that virtually complete construction was achieved onshore, considerably reducing the hook-up and commissioning activities at the offshore location. In addition, the float-on method for the PU module eliminated the need for mobilization into the Arabian Gulf of a special ultra-heavy lift vessel.

Tie-in of the various interconnecting components of the Complex took place in the period February to June 1996, leading to first gas available to the production pipeline on 7th July.

3.3 Production Gas Pipeline

The single production gas pipeline (sealine) originates in the lower deck of the PU Platform and is routed on the sea bed to its destination in the Upstream plot onshore at Ras Laffan. It is operated in diphasic mode, i.e. it transports the gas and unstabilized condensate in unrestricted contact with each other.

The contract scope awarded to Saipem in March 1994 covered the design, fabrication, installation and testing of the sealine, the principal parameters of which are:

As-installed length	80.3 kilometres
Nominal diameter (external)	32 inches
Design pressure	155 bar.a
Wall thickness	22.2 & 31.1 mm
Internal volume	36,943 m ³
Material specification	API.5L.X65
Concrete weight coating thickness	60 to 150 mm
Number of sacrificial anodes	670

The 78.7 km offshore section of the sealine was installed by the pipe laybarge "Castoro V" during the period July to September 1995. The pipe material was procured by Qatargas from Europe and coated for Saipem by NPCC at its yard in Abu Dhabi, before being transported by flat-top barge to the lay vessel. The first few kilometres from Ras Laffan were in very shallow water, with the depth then increasing gradually to the maximum depth of 53 metres at the Bravo Platform Complex site.

The termination points were near the top of the riser on the PU Platform, and upstream of the ESD valve in the Onshore reception facilities. Except for trenching in the landfall approach area, the long submerged part of the sealine rests directly on the undisturbed sea-bed. The short onshore section from the landfall to the Plant (about 1.6 km in length) is buried. In this section, two detectors have been installed to warn against the imminent arrival of a liquid slug. The detectors are housed in fenced protective pits, near the Northern Perimeter Road.

The selected route involved the sub-sea crossing of three existing facilities:

- the 34-inch North Field Phase I gas pipeline
- the 12-inch North Field Phase I condensate pipeline
- the Bahrain / UAE international telephone cable.

These crossings, in water depths of about 20m and located 14 and 16km from shore, were all completed successfully, with sub-sea bridges installed to ensure appropriate clearance between the respective components.

Testing, internal cleaning and pre-commissioning of the sealine were carried out during the first half of 1996 ; the pipeline was ready for first gas entry in July 1996.

3.4 Onshore Reception Facilities

The onshore reception facilities are located at the western side of the LNG Plant, in a segregated Upstream plot. There are three principal reasons for the segregation:

- Upstream activities are covered by a Development and Production Sharing Agreement
- Shareholdings of participants are different to those in the LNG Plant Project
- Design codes of equipment and systems are different from the Qatargas LNG Company.

The sealine enters the Upstream plot at a location 1.4 km from the beach. The line is maintained buried for its onshore portion, emerging above ground only when it is inside the plot boundary. The termination of the sealine is at the upstream side of the main ESD valve.

The reception facilities consist of a high pressure protection system, a slugcatcher, feedstock gas separation, two condensate stabilization units and off-gas recompression facilities. The slugcatcher has a liquid capacity of 2000 m³ and comprises 8 fingers of 46-inch diameter pipe joining gas inlet and liquid outlet headers also of 46-inch diameter. The condensate stabilization units are each rated at 20,000 bbl/d. The single off-gas compressor is driven by an electric motor.

To support the ongoing expansion to three LNG trains, a third condensate stabilization unit and a second off-gas compressor are being installed.

3.5 Condensate Storage and Loading

The separated and stabilized condensate is piped to the storage area, which is located about 1 km east of the LNG Plant. Here, three floating-roof tanks each of 298,000 bbl (50,000 m³) gross capacity are installed in a fenced plot.

There are three loading pumps, each of 2,000 m³/h, any two of which are used to transfer the condensate to Berth 2B in the Port. The loading line is 28 inches in diameter and about 4.5 km long, routed along the Lee Breakwater of the Port. On Berth 2B, two 16-inch loading arms are used to load the condensate into tankers. The Berth can accommodate tankers in the nominal size range of 20,000 to 300,000 DWT, dependent upon their overall physical dimension and manifold location.

3.6 Phase II / Phase I Gas Interconnection

During the build-up period to LNG production plateau, the required quantity of feedstock gas will be lower than the flowrate available from offshore. Accordingly, the opportunity for revenue receipt from condensate sales will be restricted. By using an interconnection between the dry gas systems of Qatargas' Phase II and QGPC's Phase I, it is possible to transfer surplus feedstock gas into the QGPC system and so achieve an increased condensate production rate.

The operating pressures of the two systems are normally such that flow of dry gas from NF Bravo to NF Alpha requires booster compression with electric driver. A 20-inch diameter pipeline connects the Upstream Reception Facilities area with a branch on the 34-inches diameter buried pipeline in the QGPC valve compound, north-east of the LNG Plant to facilitate such gas transfers.

Alternatively, the interconnection could serve to supply quantities of NF Alpha gas to Qatargas if need arises.

4. DESCRIPTION & IMPLEMENTATION OF THE LNG PLANT

4.1 Contracting Strategy

The front end engineering design (FEED) work was undertaken in the Houston office of the M.W. Kellogg Company from early 1992 until First Quarter 1993.

The Plant Project uses one overall engineering, procurement and construction (EPC) contract. The EPC Contract for the two-train/4 Mtpa plant and associated facilities, with an option for third LNG train, was awarded to Chiyoda Corporation of Japan in May 1993, including assignment of responsibility for three smaller long-lead items which were previously awarded by Qatargas: (i) LNG Tanks to TBMM, a consortium of SN Technigaz & Bouygues of France and Mecon & Midmac of Qatar, (ii) Cryogenic Heat Exchangers to APCI of the United States, and (iii) Compressors to Nuovo Pignone of Italy. In addition, a few small contracts were awarded and administered directly by Qatargas for such activities as site surveys, site preparation and Qatargas Head Office Building, due for completion in Second Quarter 1997.

All of the above contracts were competitively bid and awarded on lump sum basis, and Completion Packages were divided to facilitate handover during a phased period, with penalties assigned for late completions.

A Qatargas LNG Project Task Force (PTF) was established in Chiyoda's Yokohama office to facilitate rapid decision-making and approvals for matters of direct concern to Qatargas.

4.2 Summary of Process System

The Plant process system is supplied with feedstock gas from the Upstream facilities via a 30-inch diameter pipeline. Filtration and fiscal metering then takes place in the common reception facilities before the feedstock flow is divided into three streams, one to each LNG process train.

Each LNG process train consists of the following stages before the resultant LNG is directed to the storage tanks:

- feedstock inlet reception
- acid gas removal
- dehydration & mercaptan removal
- mercury removal
- liquid separation & aromatics removal
- liquefaction system
- nitrogen rejection.

Process support facilities associated with the LNG trains include:

- acid gas treatment, sulphur recovery and tail gas incineration
- fuel gas distribution
- NGL extraction, refrigerant make-up and NGL return for shipment
- gas flaring and liquid burning
- flash gas for use as fuel
- process effluent water treatment.

Utilities support facilities for the LNG trains include:

- electrical power generation
- steam generation
- cooling water circulation
- water desalination
- fire fighting water distribution
- air compression
- nitrogen generation.

4.3 Feedstock Reception Facilities

The overpressure protection system and primary condensate separation facilities are located in the onshore Upstream plot, with the resultant feedstock gas being transferred into the Plant area via a single pipeline. Initially the feedstock gas passes through a filter/separator vessel before being directed through the fiscal metering station and then divided into three streams, one to each LNG process train.

The inlet reception facilities of each train are composed of a knock-out drum, the first stage mercury removal vessel, and the duplex first stage mercury removal filters. The feedstock gas contains trace quantities of mercury, which corrodes aluminum. The two-stage mercury removal unit protects the aluminum components of the main cryogenic heat exchanger and other aluminum equipment in the LNG trains.

4.4 LNG Process Trains

In each train, acid gases (CO_2 and H_2S), mercaptans and other sulphur products are removed from the feedstock gas to meet LNG product specifications, and to prevent CO_2 from freezing out in the cold end of the liquefaction unit. Sulphur is recovered from the acid gas, solidified and trucked to the Port for shipping. The sulphur export system at the Port consists of a solid sulphur storage silo and a travelling shiploader. The silo capacity is 20,000 tonnes.

Drying of the gas is required to prevent ice and hydrate formation in the liquefaction unit, which would cause blockage of lines and equipment. Residual mercaptans are removed together with water.

Following pretreatment, the gas may then be chilled and liquefied. This is done in two steps, using two distinct refrigerant closed loops: the propane loop and a loop involving a predetermined mixture of nitrogen, methane, ethane and propane. The first loop pre-cools the gas and allows the removal and recovery of heavy hydrocarbon components which would freeze in the main cryogenic exchanger. The second loop liquefies the gas by cooling it down to minus 160°C . Gas turbines provide the power required to drive the refrigerant cycle compressors, while heat generated by the refrigerant systems is rejected to the sea by means of a once-through sea water cooling system.

After chilling by the propane loop, a separated stream of liquid consisting of ethane and heavier hydrocarbons is fractionated to recover LPGs and NGLs, as well as to produce ethane and propane make-up for the refrigerant cycle. The NGLs are returned to the Upstream plot and are combined with the field condensate previously separated from the production gas.

To liquefy the gas, the stream is then introduced into the main Cryogenic Heat Exchanger, where it is further liquefied by heat exchange with the mixed refrigerant compressor loop.

Finally, nitrogen is rejected from the LNG in order to allow it to be stored more efficiently. The flash gas stream with a high nitrogen content is recovered and used as fuel gas. The commercial grade LNG is pumped to LNG storage, at a nominal rate of 300 tonnes per hour (about 675 cubic metres per hour) from each train.

A flare and liquid burner system is provided which separately disposes of wet gas, dry gas, sour gas, and liquids.

4.5 LNG Storage and Loading

The LNG produced in the two trains is stored in three identical full-containment, double metal inner wall and concrete outer shell storage tanks for maximum safety. Each tank has a nominal working capacity of 85,000 cubic metres, and is equipped with four top entry column-mounted loading pumps each of capacity 1,300 m³/h and one circulation pump of capacity 250 m³/h. The tanks are located at the north-east corner of the Plant area, and the loading lines are routed along the Main Breakwater of the Port to LNG Berth No.1.

Two boil-off gas compressors located near the tanks recover the tank vapours and compress them for use in the fuel gas system. A balancing flare is provided nearby for the recovery system.

A fourth LNG tank and a third boil-off gas compressor are being added for the third LNG train.

LNG is loaded into carriers through three articulated loading arms, each having pipes of 16 inches diameter and capacity of 3,400 m³/h. This leads to an overall nominal loading rate of 10,000 m³/h, which means that an LNG carrier spends less than 24 hours in port at Ras Laffan. A fourth arm is used to receive the vapour generated in the ship during loading; the vapour is directed to a discharge flare located outside the Breakwater.

4.6 Utilities Support Systems

Electrical power is generated by five gas turbine drive machines, each of 28 MW ISO rating, with a sixth machine being added for the third LNG train. With this design, at least one machine is always available as spinning reserve or as standby for maintenance. The machines are simple cycle, of the GE Frame 6 type, and are installed outdoors within individual acoustic enclosures.

Two diesel engine driven machines, each of 2.5 MW rating, provide standby, emergency and restart power capability.

Steam is generated at a pressure of 10 barg in three gas-fired boilers, each rated at 146 tonnes per hour. A fourth boiler is being added for the third LNG train.

The sea water cooling system includes the intake facilities located in the Port with two sea water pumps per LNG train, the supply distribution and return systems, the return weir box, and outfall channel discharging to the open sea. Maximum water temperature differential from intake to outfall is 10°C. A fifth pump (seventh after 3 LNG trains) acts as a common spare on the connecting manifold, from which the LNG trains are supplied. All the pumps are vertical shaft suspended, bowl type with vertical electric motor drive ; capacity is 17,300 m³/h each.

Fresh water is obtained by desalination of sea water, with the units located in the Utilities plot of the Plant. Three units of the thermo-compression type are installed, each of 40 m³/h capacity.

Three fire fighting water pumps are provided, each of 1,000 m³/h capacity. The pumps are diesel engine driven through a right angle gearbox to a vertical shaft suspended bowl pump. These pumps supply sea water and are located in one bay of the intake structure in the Port. For the first hour of any incident, and for the pressurization and routine regular testing of systems, fresh water is provided from a storage tank in the Utilities plot of the Plant. Fresh fire water is pressurized by an electrical and a diesel driven pumps.

Air compression is provided by four electric motor drive machines. Air is used for instrumentation and service purposes, thus drying is undertaken before storage and distribution.

Nitrogen liquefaction is carried out in two units, equipped with two liquid nitrogen storage tanks of 90 m³ each to provide an inert gas for snuffing purposes and maintenance evacuation of enclosed spaces.

4.7 Construction

Construction of the grass root LNG Plant required an enormous effort by Chiyoda and its subcontractors resulting in a peak construction manpower build up of over 9,000 personnel in October 1995. As of January 1997 a total of over 57 million man-hours had been spent in constructing the facility. Totals of some of the material quantities utilized in Plant construction are:

□	Concrete Poured	625,590 MT
□	Steel Erected	32,449 MT
□	Piping Installed	729 KM
□	Electrical Cable	2,368 KM
□	Main Instrument Cable	1,202 KM
□	Pieces of Equipment	1,912 Pcs
□	Weight of Equipment	27,300 MT
□	Building Space	67,592 M ²

Consistent with the strategy of the EPC contract, Plant construction efforts focused on the phased completion and hand-over of stand alone facilities to Qatargas to allow accelerated start-up and operational activities.

The first of the Plant facilities to be completed were the site industrial buildings. These facilities included such buildings as the laboratory, fire station, workshop, training centre and gate house which were handed over to Qatargas in September 1995.

Following hand-over of the buildings, the Plant utilities systems, including fuel gas, power generation, fire protection, compressed air, effluent treatment and seawater intake, were the first operational facilities to be completed and were handed over to Qatargas for start-up and operations in January 1996.

In May 1996, the remaining utilities systems required for operation of the first LNG train, including desalination and steam generation systems, were completed and handed over.

On September 1, 1996 the next major milestone in construction of the Plant was achieved when the first LNG train was completed and handed over to Qatargas one month ahead of schedule. Early completion of this milestone allowed Qatargas to accelerate start-up activities and produce the first drops of LNG on November 15, 1996 well in advance of the first LNG shipment date.

Finally, on December 8, 1996 construction of the second train was completed and handed over to Qatargas three weeks ahead of schedule.

Construction of the third LNG process train is currently progressing well ahead of schedule

5. PROCUREMENT OF SHIPPING

5.1 The LNG Carrier Fleet

Qatargas has full responsibility for the transportation of LNG. The two train project requires a fleet of seven LNG carriers, each of 135,000 cubic metres nominal capacity, to transport annually 4 million tonnes of LNG from Qatar to Japan. Three similar carriers are required to transport the additional 2 Mtpa of LNG that will be available from the third train, bringing the total fleet to 10 carriers.

LNG carriers have been internationally bid by Qatargas in two stages: firstly among shipyards and then among shipowners. All carriers have been or are being built to Qatargas' specifications in 3 yards in Japan (Mitsui Engineering & Shipbuilding, Mitsubishi Heavy Industries, and Kawasaki Heavy Industries) for time-charter to Qatargas by a consortium of Japanese shipowners and operators (Mitsui O.S.K., Nippon Yusen Kabushiki Kaisha, Kawasaki Kisen Kaisha, Showa Line, and Iino Kaiun Kaisha).

The vessels are of the five-tank Moss Rosenberg spherical tank design and have a normal cruising speed of 19.5 knots, offering a round trip voyage time between Qatar and Japan of just under one month. They have steam turbine driven propulsion, using boil-off gas from the LNG as primary fuel whenever possible (or forced boil-off when desirable) and bunker oil at other times.

The vessels have identical physical dimensions, including an overall length of 297.5 metres and a summer laden draught of 11.2 metres, and a design dead weight of about 68,200 tonnes. There is maximum accommodation for 46 crew, and a normal complement of 29 persons.

The first two of the ten LNG carriers: Al Zubarah & Al Khor, entered service, respectively, in early November 1996 and early December 1996, with the next two - Al Rayyan & Al Wajbah - coming into service in April and May 1997. The final ship of the ten-vessel fleet will enter service in June 2000.

At plateau LNG production for three trains, the ships will deliver about 108 cargoes per year.

5.2 Shipment of Other Products

Responsibility for arranging condensate and sulphur ships rests with the customers:

- Condensate Berth 2B at RLP will cater for ships in the nominal range of 20,000 to 300,000 DWT, provided the ship's principal dimensions are acceptable to the Port and the Berth.
- Sulphur Berth can accommodate ships in the nominal range of 8,000 to 45,000 DWT, with the ship-loader able to move along the wharf and reach the majority of a ship's holds. The normal loading rate is up to 1,000 t/h for the larger ships who do not have a trim problem at this quantity; smaller ships can be loaded at reduced rate if necessary.

6. MAJOR QATARGAS DEVELOPMENT DECISIONS

At each of the design stages of development of the Qatargas Projects, i.e. during conceptual, front end engineering design and detailed engineering, several major decisions had to be taken. The background to some of these decisions is now reviewed.

6.1 Configuration of Offshore Platform Complex

The QGPC North Field Alpha Offshore Platform Complex was designed in the late 1980's - it was launched in 1987 and production successfully started in mid-1991. NF Alpha yields about 750 Mscfd of lean gas and about 5,000 tonnes per day of natural gas liquids.

NF Alpha consists of 6 platforms with 2 bridge supports and 7 connecting bridges. The platforms are Living Quarters, Utilities, Process, Wellheads (2) and Flare. During installation, each of the topsides assemblies was lifted into place by floating cranes.

For the Qatargas 900 Mscfd Bravo Offshore Platform Complex, the possibility of combining the Process and Utilities on to one platform was investigated. Although the topsides weight would exceed 7,000 tonnes, the technique of floating the topsides into place on its

transport barge was considered to be sufficiently developed as to merit further review. As a result of this review, which included weather data for the installation site and the capability of the fabrication yards to handle such a large one-piece weight at load-out, the decision was made to adopt a combined Process and Utilities Platform. The number of platforms at the Bravo Complex is therefore five, for the initial 4 Mtpa LNG development, with 6 connecting bridges.

6.2 Operation Mode of Production Gas Pipeline

The production pipeline parameters for QGPC's NF Alpha production gas pipeline were finalized in the late 1980s. The overall length is about 210 kilometres, of which 80 kilometres are sub-sea from NF Alpha to the landfall at Ras Laffan and the remaining 130 kilometres are buried on land for the route to Messai'eed. Having regard to the length of the route and the slight uncertainty of the condensate content of the raw wellhead gas before actual production started, QGPC opted for two separate pipelines. The dry gas pipeline is therefore 34 inches in diameter, and the condensate pipeline is 12 inches in diameter.

For the Qatargas NF Bravo development, the route length is only the 80 kilometres to Ras Laffan, and there is increased confidence in the condensate content of the raw wellhead gas. Accordingly, Qatargas, supported by extensive simulation calculation, has opted for the most economic solution of a single production gas pipeline to be operated in diphasic mode, with a suitably sized slugcatcher included in the onshore reception facilities.

6.3 LNG Plant Cooling Medium

Since there is abundant sea water on a coastal site such as Ras Laffan, the choice of water rather than air for cooling purposes would seem to be a simple one. Yet in a similar hot-climate coastal environment in Western Australia, the North West Shelf LNG Plant commissioned in 1989 had chosen air cooling and had operated successfully on air. At Ras Laffan the main operational limitations for cooling water are the maximum summer water temperature of 35°C and the maximum permitted differential temperature from intake to outfall of +10°C. After evaluation of all technical and commercial aspects, it was decided to adopt a once-through direct sea water cooling system.

At the time the decision was made, the sea water intake was to be located on the Northern coast, with the supply pipework route length of about 2,100 metres to the Plant boundary. The subsequent decision to relocate the intake to the Inner Harbour of the Port increased this route length to about 4,500 metres. The relocation did not change the balance away from water cooling but enabled the cooler water present in the deeper areas of the sea at Ras Laffan to become more readily available, because the Port entrance is dredged to -15.0m CD, the main basin is dredged to -13.5m CD and the cill elevation of the water intake structure is at a natural depth of about -6.0m CD. It is evident that the original northern coast location would not have provided such cool intake water without very major civil engineering, because the solar heating effect is significant and the same -6.0m CD water depth could not be achieved until a distance of about 1400 metres from the beach.

It is estimated that this relocation of the seawater intake facility saved about \$200 million.

6.4 Plant Cooling Water Pipework Material

Within the Plant, the 84-inch, 72-inch, 44-inch and 30-inch diameter pipework had to be buried to ensure that operating access in and around the process trains was not impeded. The selected material is of the concrete walled type with pressure containment by steel tube. Joints are of the sliding male and female type, having peripheral grooves filled with sealant. Internally, the gap between pipes is filled with concrete grout.

Outside the Plant boundary, the pipework is above ground, has a constant 84-inch diameter, and is made from carbon steel with "flake-glass" lining. Joints are butt-welded, with the lining made good by a manual coating application. Externally the pipework is coated with epoxy paint and finished in the usual grey colour. The pipework is supported by steel saddles on concrete sleepers, with adequate clearance gaps under the pipes to avoid the build-up of wind-blown sand.

6.5 Plant Refrigerant Compressor Drivers

During the conceptual design stage, the respective merits of steam turbines and gas turbines for the refrigerant compressor drivers were reviewed:

- For the drive power required, and the LNG production per train, it was noted that in a similar ambient temperature situation in Western Australia, gas turbines of the two-shaft GE Frame 5 type were operating successfully. The addition of electric helper motors for the gas turbines was also a proven development, both in Australia and elsewhere, but motors were eventually found to be unnecessary for Qatargas.
- For the modular process train concept that Qatargas had adopted, the steam turbine approach (with its necessary high pressure boilers and distribution system having to be extendible without further shutdown of initial facilities) represented a commercial disadvantage. In addition, disposal of the medium pressure and low pressure steam before eventual condensation into returning boiler feed water imposed undesirable rigidity on many of the auxiliary driver functions in the process trains.

Since both drivers were technically acceptable and equally reliable, the GE Frame 5 drivers were selected. This was followed by the selection of the single-shaft GE Frame 6 type gas turbine driver for power generation duty.

6.6 LNG Storage Tank Foundations

Above-ground LNG storage tanks are usually supported on either piled, ringwall or mat foundations. For Qatargas, the choice was between the piled and the mat type, with the piled foundation originally thought to be necessary due to the ground in that part of the Plant Site having been elevated by filling and compaction. An air gap between the ground level and the underside of the tanks or an electrical heating system was required to avoid the freezing effect of the cold structure on the soil. Piles would have been surrounded at lower levels by sea water saturated soil, as the water table in any excavation was seen to be quite high and to have a direct relationship to the natural tidal height (at the coast) at any time.

Tests on the elevation of the underlying rock and the stability of the compacted fill revealed that a mat foundation was possible, and an economic assessment was carried out. This assessment showed the mat foundation, with electrical heating, to be economically and technically attractive. Accordingly, the mat foundation was adopted ; this saved the base two-train project about \$4 million.

6.7 Location of LNG Marine Flare

In view of the distance of LNG Berth No.1 from the storage tanks, and also from the original shoreline in the Port, a separate marine flare located over water was recognized as being necessary, since compression of return vapour generated during LNG loading was to be avoided.

Because locating the flare inside the harbour would interfere with the vision of pilots entering the harbour, the flare was located outside the Main Breakwater.

6.8 Configuration of Approach to LNG Berths in Port

Throughout the Qatargas conceptual design and FEED stages, QGPC indicated that the approach to each of the four LNG Berths inside the Main Breakwater would be via a two-trestle arrangement supported on piles or concrete blocks. However, the approach to the Condensate Berths was always envisaged as a narrow stone-filled embankment attached to the inside of the Lee Breakwater with the distance from the outside of the Main Breakwater being the technical minimum for jacket installation and on-land radiation safeguards.

As the design development of the LNG Berths progressed, the future operational access difficulties that would be faced when installing Berth No.2 piping on the combined Berth 1/2 trestle, and when building a further parallel trestle for Berths 3/4 in close proximity to the operating Berth 1/2 trestle, were recognized. The alternative was to build a common in-filled embankment, starting off very wide but becoming narrower as each Berth was reached and passed. Eventually QGPC opted for the change to the wide embankment, with a branched causeway about 400 metres in length leading to Qatargas' LNG Berth No.1. A division of responsibility between QGPC and Qatargas was established when the approach was a trestle, which would not permit simultaneous

access by QGPC's and Qatargas' contractors. For commercial reasons this respective responsibility was retained, but when applied to the embankment arrangement resulted in unusual termination points for work. One example was the Berth approach road, which was QGPC's responsibility for the final 1,200 metres out of 3,500 metres, i.e. the section at the seaward end that would have been on the Berths 1/2 trestle.

It should be noted that in hindsight there were significant access benefits obtained from the embankment arrangement during construction.

7. ISSUES AND RELATIONS WITH OTHER PARTIES

7.1 Interfaces with Other Parties

In addition to interface issues within the Qatargas overall project involving (i) Qatargas Upstream Project, (ii) Qatargas LNG Project, (iii) Qatargas Commercial & Shipping (QCS, formerly Qatargas Shipping Team, QST), and (iv) Qatargas Finance Team (QFT), the list of principal external interfacing parties comprises:

- QGPC's Ras Laffan Port Project (RLP)
- Ras Laffan LNG Company Ltd (RasGas)
- Qatar Public Telecommunications Corporation (Q-TEL)
- QGPC's Ras Laffan Industrial City (RLIC)
- QGPC's Operations Directorate
- Qatar Government Ministries (mainly Municipal Affairs & Agriculture, and Electricity & Water).

The Qatargas involvement with each external party is now reviewed in brief in the following sections.

7.1.1 Ras Laffan Port Project (RLP)

In the late 1980s, QGPC established a major project team to draw a Master Plan for the Gas Utilization in Qatar, including the development of a new industrial centre of Ras Laffan.

Prior to 1991, the Qatargas LNG Plant was intended to be constructed on land fronting the beach to the South of QGPC's existing NGL facility at Messai'eed Industrial Area. Many of the support services needed for Plant construction and operation already existed nearby, such as a project materials, import berth and condensate and sulphur loading berths, which would only need expansion by QGPC.

For national strategic reasons it was then decided to make the Qatargas Project the first industry in a new grass-roots industrial area being established at Ras Laffan. On its part, QGPC undertook to provide from its own funds the differential facilities that would be needed at Ras Laffan, when compared to those facilities available at Messai'eed. Central to this decision was the design and construction of a new Port of Ras Laffan, including berths for LNG, condensate and sulphur export, and materials arrivals as well as seawater intake and outfall facilities. With Ras Laffan being originally a grass-roots area traversed only by two buried pipelines from the North Field Phase 1 development, much infrastructure in the form of earthworks, roads, pipe culverts, drainage and street lighting was needed.

The involvement of QGPC-RLP as an outside party to the Qatargas projects (in addition to QGPC being the major shareholder) introduced the advantage that the Port facilities and the supporting infrastructure were implemented without Qatargas being involved in frequent and detailed contact with the various Government ministries having jurisdiction over such matters. Instead these interfaces were implemented among the Port users and QGPC.

QGPC's RLP contracting strategy was to make the early award of one very major EPC contract for the civil/marine aspects of the Port, and to follow this with a series of relatively smaller contracts for the infrastructure work, which was principally inland of the original shoreline. Major Contract R-1 was awarded to the Condotte & Partners Joint Venture (of Italy) in September 1991, with the basic conditions being lump sum and an overall

completion date of 31st December 1996. The contract included two important interim milestone completion dates, namely 1st April 1994 for the Materials Berth and 31st December 1995 for the LNG Berth No.1. Both these interim dates and the overall completion date were met allowing equipment installation by Qatargas/Chiyoda on the structure. The civil engineering consultants L.G. Mouchel & Partners of U.K. were appointed by QGPC as Managing Consultants for the Condotte contract.

The other significant contract awarded by RLP was for the civil construction of the Sea Water Intake Structure in the Harbour, and the Outfall Channel from the LNG Plant to the Northern coast. The contract was awarded to QBC-Costain in July 1994, for completion of the SWI by 30th April 1995 and of the Outfall by 30th September 1995. Both dates were met for the handover to Qatargas and Chiyoda, enabling equipment installation to progress.

In summary, the coordination of RLP's work with the necessarily "follow-on" nature of Qatargas' work was time-consuming and complex, but the end result was most successful. The completed facilities are expected to adequately meet Qatargas' requirements for the life of the LNG Plant.

7.1.2 Ras Laffan LNG Company Ltd (RasGas)

The Ras Laffan LNG Company Ltd is implementing the second LNG development at Ras Laffan, with first shipment of LNG planned some 30 months later than Qatargas. RasGas' Plant Site is located immediately to the South of the Qatargas Site, and RasGas' products are to be exported through Ras Laffan Port.

Close contact with RasGas personnel has been maintained since the start of their FEED work in mid-1994. This was to ensure the maximum continuity of thought concerning respective scopes of work and facilities planned by Qatargas, RasGas, and RLP. It was also to ensure that future construction work by RasGas will not have any adverse effect on the operational activities of Qatargas.

7.1.3 Qatar Public Telecommunications Corporation (Q-TEL)

Q-TEL is the only authorized provider of communications systems, services and equipment for the State of Qatar. In addition to operating the usual public services of a modern country, Q-TEL also acts as sub-contractor for the installation of private systems needed to support major developments such as Qatargas. Q-TEL's jurisdiction also covers the allocation and monitoring of frequencies for radio communications with offshore oil and gas platforms in Qatari territorial waters.

Regular contact has been maintained with the Q-TEL Frequency Management Department, as a wide range of differing radio systems have required both frequency allocation and equipment importation permissions. These have ranged from the transhorizon radio system, used to communicate with the offshore facilities, to simple systems required for telemetry, such as the slug detection in the production gas pipeline and the ship docking monitors on LNG Berth No. 1 and Condensate Berth 2B.

An outline specification for the private automatic branch exchange (PABX) telephone system was produced by Qatargas during the F.E.E.D. stage. This was submitted to Q-TEL and they proposed, and subsequently supplied as sub-contractor, a total of five similar systems, including one installed on the Offshore Platform Complex. These are equipped with direct-dial-in (DDI) facilities to minimize the need for manual operator intervention, and to improve the efficiency of communications for Qatargas personnel.

The other major item supplied by Q-TEL was the Qatargas dedicated UHF Trunked Mobile Radio System (TMR), which provides mobile communication across the entire Plant and Port areas.

7.1.4 Ras Laffan Industrial City (RLIC)

The RLIC organization was established to operate the Ras Laffan Port after its opening for hydrocarbon-related traffic in mid-1996, and to administer the onshore infrastructure external to the LNG Plant boundary. Operation of the Port is being undertaken in accordance with the Port Rules & Regulations, an important document to which Qatargas had significant input.

The Upstream and Downstream Port Users Agreements, executed between Qatargas and QGPC in September 1995, cover the terms, conditions and charges for the use of the Port. Provision of ship navigation aids and pilotage, towage and mooring services are the responsibility of RLIC. Product cargo handling and construction materials unloading in the Port are the responsibility of Qatargas.

RLIC also undertakes the environmental supervision of Qatargas' ongoing construction activities and operational activities, both in the Port and onshore; this has so far been confined to RLIC pointing out minor construction practice deviations to Qatargas, and Qatargas supplying operational data to RLIC (e.g. Camp effluent water quality).

7.1.6 Qatar Government Ministries

Important contacts with Qatar Government Ministries have been key to the development of Qatargas. The two Ministries involved most were Municipal Affairs and Agriculture (MMAA) and Electricity & Water (MEW).

The MMAA was the approval authority for the route of the Qatargas temporary access road from Al-Khor to the Plant Site, and agreement was reached for construction to begin in 1993. The MEW had plans to extend the national electrical power grid to Ras Laffan, but the timing was uncertain and so the MEW approved Qatargas' on-Site power generation scheme, with no grid-connection facility. Subsequently, Qatargas upgraded its design to accommodate electrical interconnection with an outside grid or another industrial plant. Also, the MEW was consulted when Qatargas was selecting the lining material for the sea water pipework because the MEW has long experience of warm sea water utilization in Qatar ; MEW's advice was helpful in finalizing Qatargas' design.

7.2 Shared Facilities

The remoteness and grass-roots nature of the onshore development at Ras Laffan has made the costs of providing the supporting facilities relatively expensive. Accordingly, if the essential facilities can be shared in some way with other

interested parties, there is the opportunity for cost savings and/or improved reliability for Qatargas and other party.

There are two principal categories of shared facility, namely internal and external to Qatargas.

7.2.1 Internal Shared Facilities

Internal shared facilities arise because of the differing corporate structure and shareholdings in the Upstream and LNG Plant Projects within Qatargas.

The onshore part of the Upstream Project is a relatively small, but still important, portion of the facilities constructed at Ras Laffan. As such, the provision of utilities equipment and other supporting systems was judged to be inordinately expensive. Provision by marginal increase in the detailed scopes of work or in the capacities of the systems already being implemented for the LNG Plant was therefore economically attractive.

In addition to many other minor interconnections and arrangements, the principal shared facilities are:

- Provision of utilities including power, fire water and instrument air, etc.
- Provision of space in Head Office Building, Canteen, Laboratory, etc.
- Provision of space in spare parts warehouses and storage
- Provision of emergency vehicles, e.g. fire trucks and ambulance
- Provision of mobile maintenance vehicles, e.g. cranes
- Provision of construction camp accommodation
- Provision of start-up gas for production pipeline initial pressurization.

7.2.2 Shared Facilities with RasGas

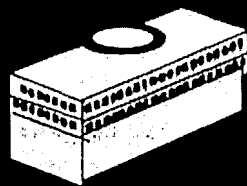
RasGas' products are to be exported through Ras Laffan Port, LNG via the dedicated LNG Berth No.2, condensate via Condensate Berth 2B, and sulphur via the sole Sulphur Berth. The latter two export facilities in the Port will be permanently shared with Qatargas, under an external agreement that is being developed.

In addition, certain of Qatargas' other facilities have been identified as suitable or potentially suitable for sharing with RasGas, either to reduce costs or to enhance the overall reliability for one or both parties. Two examples are the interconnection of the ethane and propane refrigerant storage of the two Plants, and the crossover of the LNG loading lines such that Qatargas' LNG could be loaded through RasGas' LNG Berth No.2, and vice versa for RasGas' LNG through Qatargas' LNG Berth No.1.



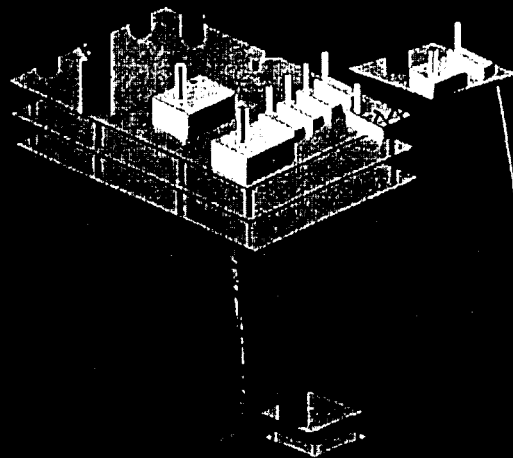
QATAR GAS FIELD

98 PEOPLE
MAX.



LIVING
QUARTERS

PROCESS &
UTILITIES



WELLHEAD
PLATFORM No3
5 wells

WELLHEAD
PLATFORM No2
8 wells

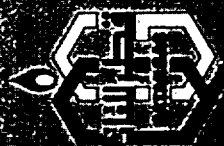
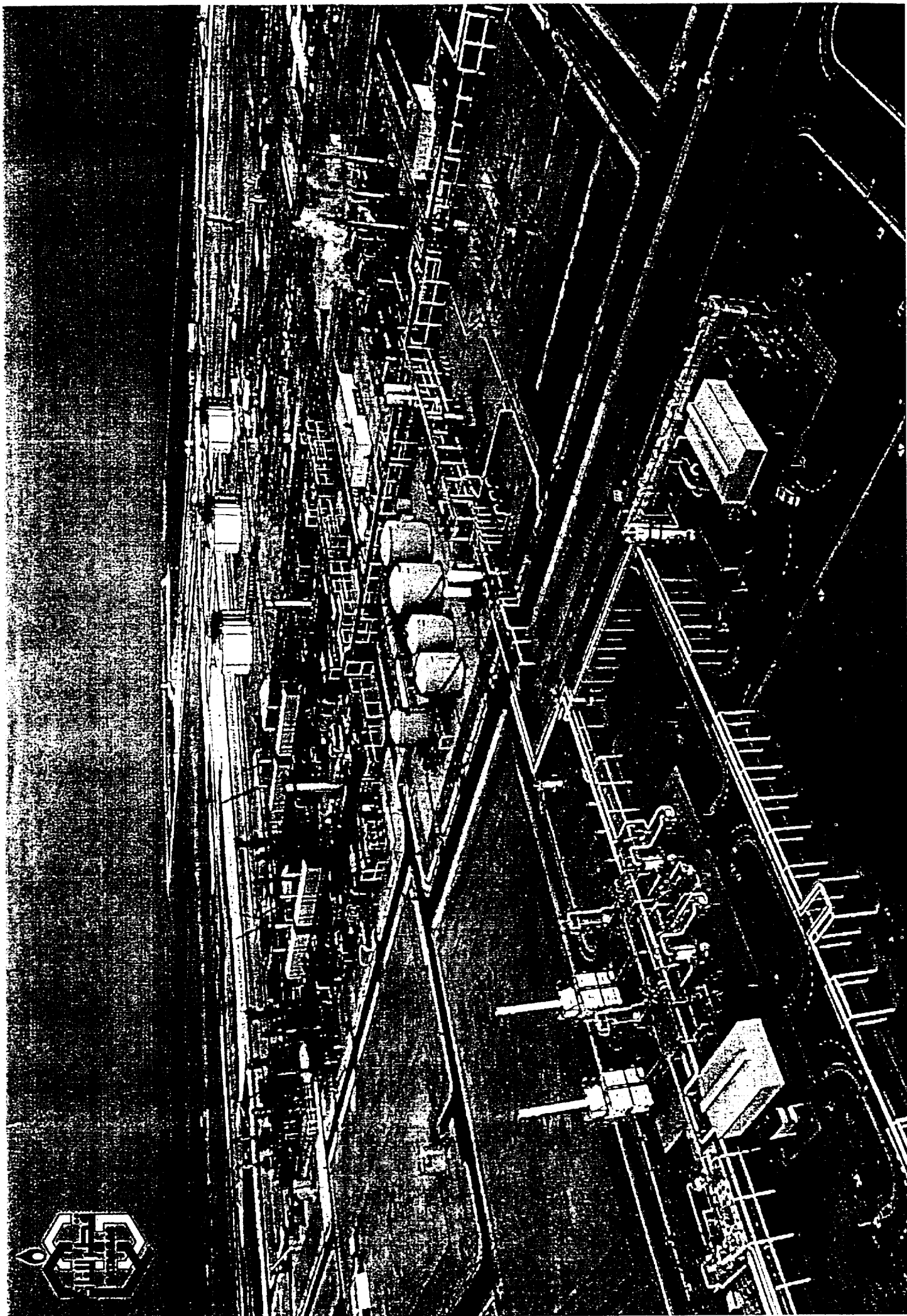

FLARE

32" pipeline (82 KM)

WELLHEAD
PLATFORM No1
7 wells

WATER DEPTH = -53 M CD

RAS LAFFAN





“Middle East Gas : Prospects & Challenges”

Session (3)

Qatar's Gas

Paper No. (3-3)

The Ras Laffan LNG Company : The Commitment of Today, The Challenge of Tomorrow

Neil Kelly

**Managing Director, Ras Laffan LNG Company,
QATAR**

THE RAS LAFFAN LNG COMPANY

THE COMMITMENT OF TODAY, THE CHALLENGE OF TOMORROW

INTRODUCTION

The oil and gas industry has been long established in Qatar and been an important element in the country's economic growth. The giant and prolific North Field is one of the world's largest offshore non-associated gas fields with proved and probable gas in place that is estimated to exceed 370 trillion standard cubic feet (TSCF). The North Field will supply buyers with a secure source of Liquefied Natural Gas (LNG) for many decades to come.

As the 21st century comes closer, Qatar is establishing itself as a leading world supplier of clean-burning natural gas in the form of LNG. The Qatar Liquefied Gas Co. Ltd. (Qatargas) LNG project is Qatar's first entry into the LNG supply market. Trains 1 and 2 are now operational to supply the Japanese market, and the first LNG shipment carrying 65,000 metric tons of LNG sailed for Japan on December 23, 1996. With this achievement, the State of Qatar and its partners have firmly established Qatar LNG as a well accepted and preferred choice in the world LNG market place.

Now, Qatar General Petroleum Corporation (QGPC) and Mobil have joined together for Qatar's second flagship LNG project by formation of the **Ras Laffan Liquefied Natural Gas Company Ltd.**

A diagram showing the location of the North Field gas and offshore production facilities in Qatar is given in Figure 1.

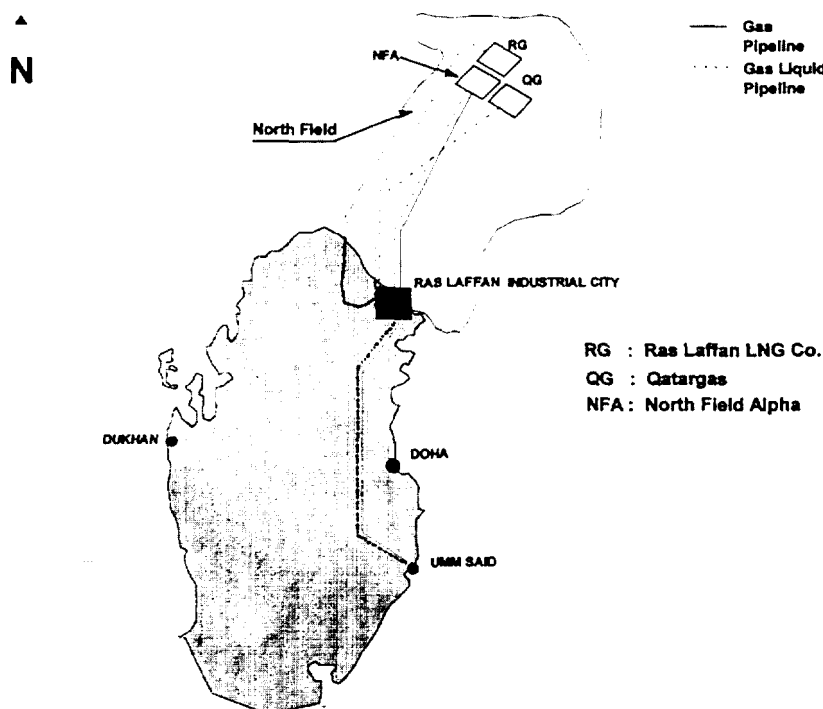


Figure 1

The Company

Ras Laffan LNG Company Ltd. (**RasGas**) was established by Emiri Decree in 1993. QGPC holds a 70% interest and Mobil holds the remaining 30% interest. In December 1996, QGPC and Mobil executed a Heads of Agreement in connection with granting Itochu Corporation and Nissho Iwai Corporation participating interests in the company. After the

final agreements are executed the shareholding structure of the company will be QGPC 66.5%, Mobil 26.5%, Itochu Corporation 4% and Nissho Iwai Corporation 3%.

QGPC is wholly owned by the State of Qatar. Today, QGPC operates in all sectors of the oil and gas industry in Qatar. It has the responsibility for exploration, drilling, production, marketing, refining, transport and storage of oil and gas, their derivatives and by-products. In addition, QGPC has joint ventures with industries engaged in manufacturing and marketing petrochemicals and fertilizers. QGPC operates the North Field Alpha facilities which is a major offshore complex (in the North Field) supplying 800 Million Standard Cubic Feet (MMSCF) of gas per day for industry and domestic fuel and export of hydrocarbon liquids. QGPC is also the majority shareholder in the Qatargas LNG project with a 65% interest.

Mobil is one of the world's largest integrated international oil and gas companies and is involved in exploration and production of oil and gas worldwide. Mobil has over 20 years experience in every phase of the LNG business and is the second largest producer and marketer of condensate in the world. Mobil also holds a 10% interest in the Qatargas project.

Itochu Corporation and Nissho Iwai Corporation are both leading *sogo shosha*, or general trading companies. Both these corporations are engaged in operations that range from the distribution of raw materials to provision of finished products to end users. The energy division of Itochu has considerable experience in the marketing and offshore trading of LNG, LPG, crude oil and petroleum products. Nissho Iwai has been a leader in Japan's LNG trade for about two decades and is engaged in the transportation and marketing of LNG to Japan.

QGPC also owns and operates the new world-class Port facilities which were completed at Ras Laffan Industrial City by the end of 1996. The Qatargas and RasGas projects will be integrated into the Port infrastructure that is being developed. An overview of the Ras Laffan Industrial City area showing the location of the existing and future industries is shown in Figure 2.

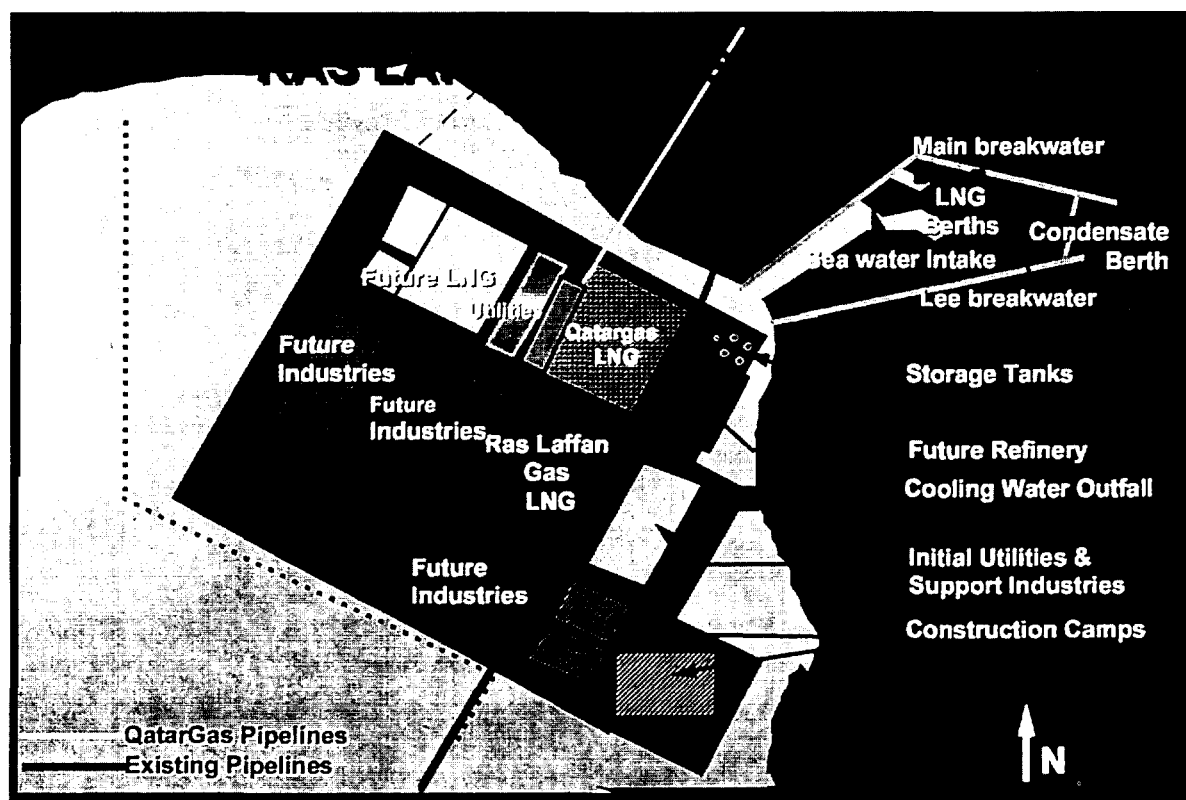


Figure 2.

The Vision

The RasGas project is being developed as a market driven, multiple-train LNG project to supply Qatar LNG to world markets.

The initial project production capacity is 5 Million Tonnes Per Annum (MMTA) from two 2.5 MMTA trains with first LNG deliveries scheduled for mid - 1999. The design will allow additional individual LNG trains and associated infrastructure to be incrementally added as the market demands. The plant site layout has been designed to easily accommodate expansion to more than six trains.

Project Foundation

The Ras Laffan LNG project foundation has been firmly established by the following factors :

- Huge North Field Reserves
- The Port Infrastructure
- The Sale and Purchase Agreement with Korea Gas Corporation

Huge North Field Reserves :

The North Field extends over an area of 6,000 square kilometers underlying the territorial waters off the north-east coast of Qatar. The North Field was discovered in 1971, and is one of the largest known non-associated gas fields in the world, with proved and probable gas in place that is estimated to exceed 370 TSCF (approximately equivalent to 63 billion barrels of oil).

Development of the North Field commenced in 1991 when QGPC developed the North Field Alpha (NFA) complex. This facility produces 800 MMSCF of gas per day and approximately 30 thousand barrels per day of condensate. By the year 2000, the North Field will also supply gas to the Qatargas Project to produce 6 MMTA of LNG for export. RasGas will produce a further 5 MMTA of LNG, initially.

The gas drawdown from the North Field over a 25 year period to accommodate the combined requirements of NFA, Qatargas, and RasGas industries will be less than 9 % of the estimated total recoverable gas reserves (Figure 3).

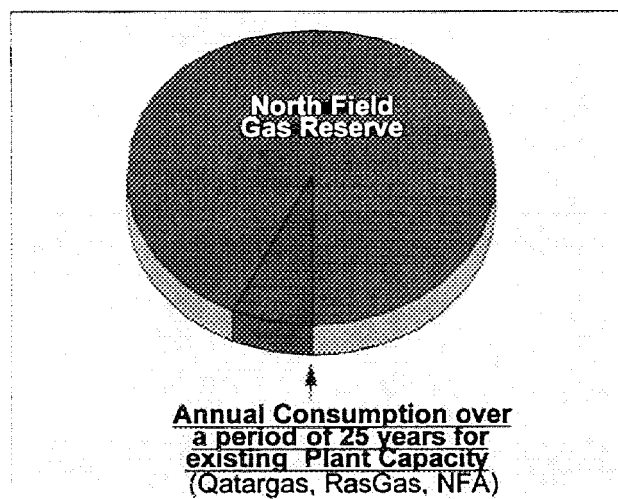


Figure 3

The Port Infrastructure :

QGPC has invested approximately US\$ 1 billion in the construction of new world class port facilities to support the development of Ras Laffan Industrial City. Ras Laffan Port, which is operated by QGPC, will accommodate product shipments from up to 4 LNG berths, 6 liquids/chemicals berths, and two dry cargo/bulk solid berths. In addition, one Ro-Ro/Lo-Lo berth plus berths for tugs and launches will be provided. The RasGas Project will be fully integrated into this Port infrastructure. A diagram of Ras Laffan Port is shown in Figure 4.

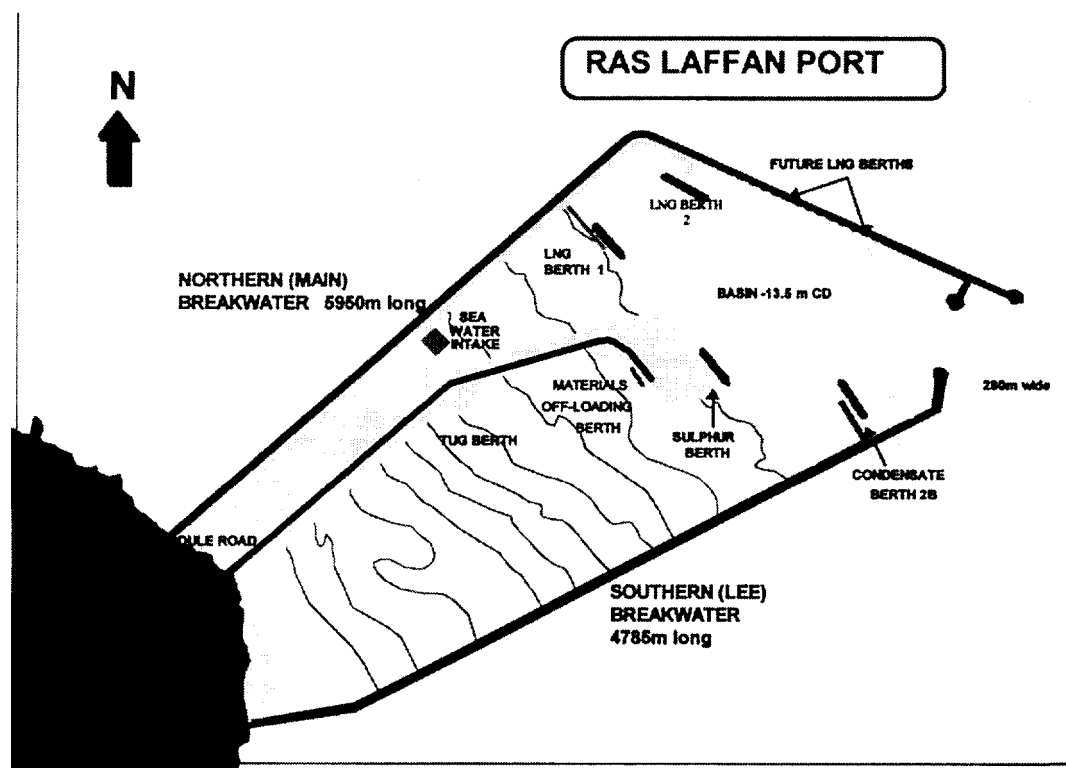


Figure 4

The Sale and Purchase Agreement (SPA) with Korea Gas Corporation:

The LNG market is characterised by long term take-or-pay sales contracts. The long term nature of these arrangements is a reflection of the considerable financial investments required by the participants at all points in the production and consumption chain, creating a strong mutual commitment to a trade by sellers and buyers.

On October 16, 1995, RasGas and Korea Gas Corporation executed an SPA for 2.4 MMTA of LNG, with deliveries scheduled to begin in July 1999. The contract term runs until 2023 with provision to extend.

The RasGas LNG Project

The RasGas LNG project is being constructed for initial production capacity of 5 MMTA from two 2.5 MMTA trains. The project consists of both offshore and onshore facilities. The offshore facilities are located north of North Field Alpha facilities and cover a development area of 10 x 10 km (Fig 1). The project will develop and produce gas from the Khuff formation at a nominal subsea depth of approximately 9500 feet.

The onshore LNG facility is located on a new site in Ras Laffan Industrial City which is directly adjacent to the Qatargas LNG facility. Figure 5 below gives an overview of the Ras Laffan Industrial City showing the location of Qatargas, RasGas and Ras Laffan Port area.

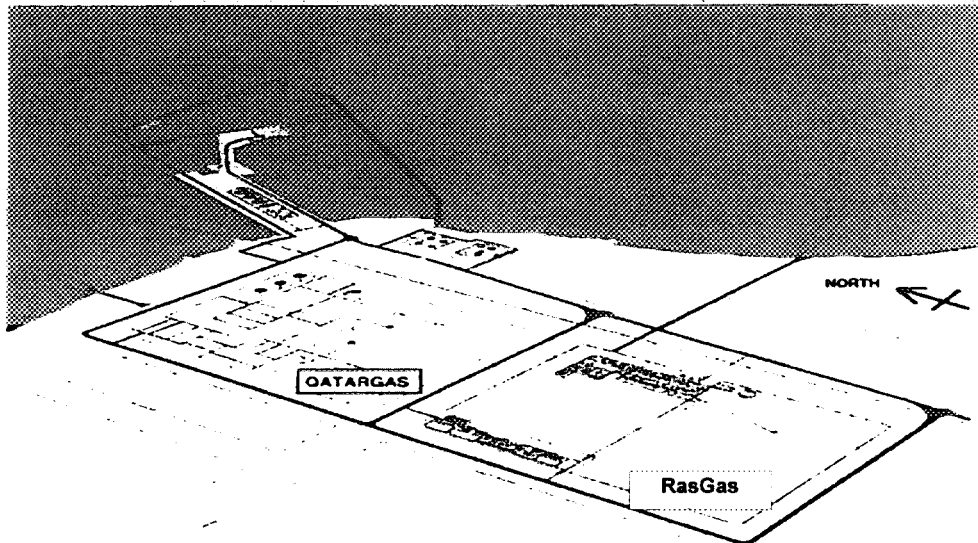


Figure 5

RasGas plans to drill 15 wells from three wellhead platforms spread over the 100 sq.km contract area. The normal flow rate from these 15 wells will be sufficient to manufacture 5 MMTA of LNG.

The offshore facilities will consist of a central complex of bridge-linked platforms, two remote nine-slot wellhead platforms, two wet sour service subsea intrafield pipelines, and various support facilities. These facilities are designed to extract gas, separate entrained water and produce condensate. After the gas is dehydrated and condensate is dewatered, the gas and condensate streams will be recombined and transported to shore through a 32 inch two-phase flow pipeline. The onshore inlet receiving facilities are designed to handle the sour two-phase production stream.

An overview of offshore facilities is shown in Figure 6.

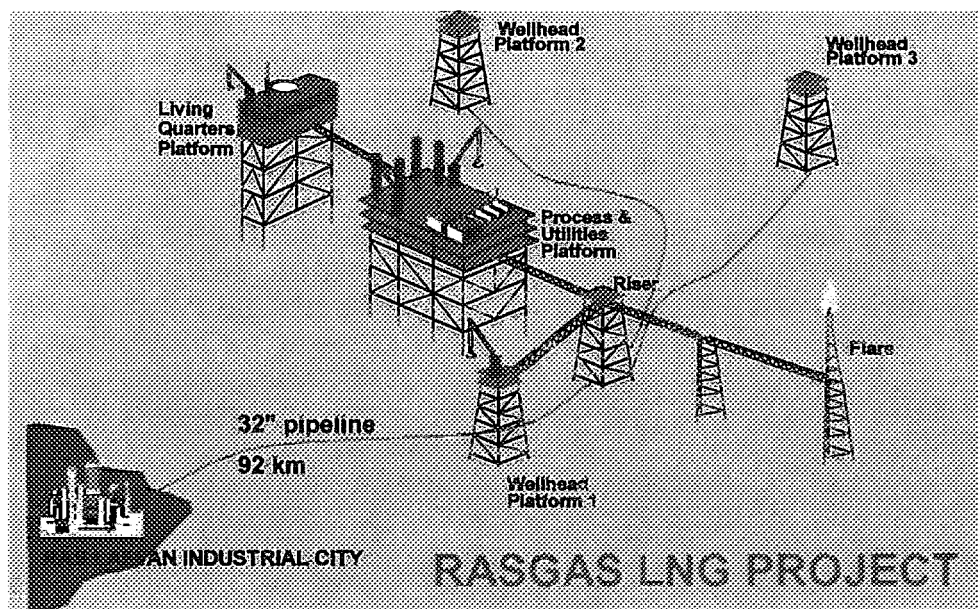


Figure 6

The onshore facilities will consist of inlet gas reception and treatment facilities, condensate stabilization, gas liquefaction, sulphur recovery, and storage and loading facilities plus all necessary utility and offsite systems and infrastructure. The onshore facilities comprise two LNG trains, each with a capacity of 2.5 MMTA. The LNG plant is designed to also produce 45,000 barrels per day of stabilized condensate and 312 tons per day of solid sulphur.

The overall process scheme is illustrated in Figure 7.

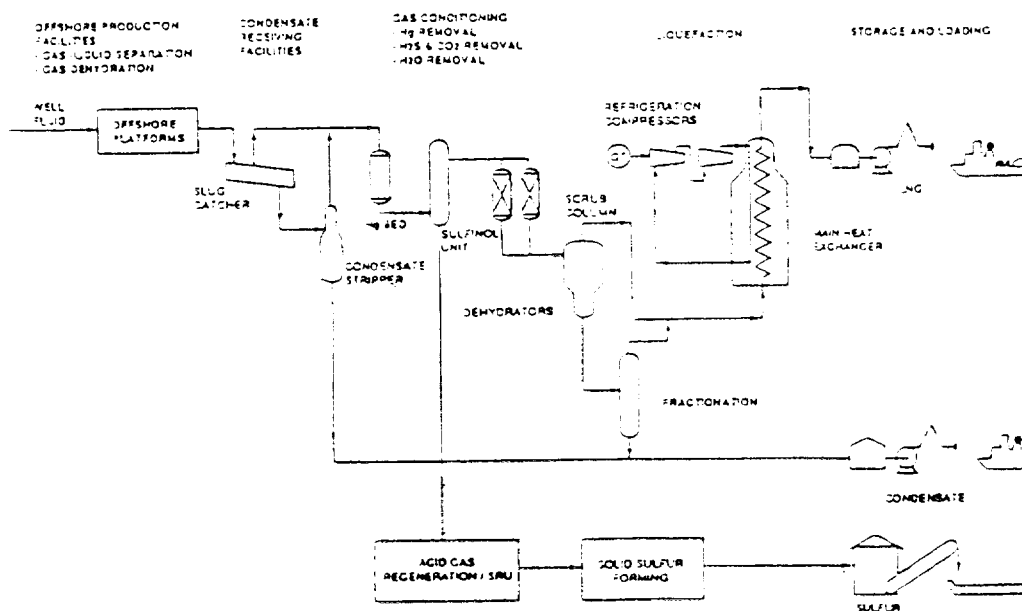


Figure 7

Project Execution

RasGas drilled and tested a delineation well in 1994, the results of which verified gas quality, well deliverability and gas reserves in the project development area to support a two train 5 MMTA LNG plant for 25 years. Also in 1994, Front End Engineering Design (FEED) work commenced for both the Onshore and Offshore facilities with the objective of providing project scope definition and bid packages suitable for lump-sum bidding. FEED work for the Onshore facilities was performed by Chiyoda Corporation; FEED work for the Offshore Facilities was completed by Hudson Engineering Corporation.

Key to the project execution strategy and schedule was the bidding and award of four critical long-lead items prior to award of the main detailed engineering, procurement and construction (EPC) contracts for the Onshore and Offshore facilities. During 1995 RasGas progressed with competitive bidding and awarded contracts for the following long-lead items: (1) LNG Storage Tanks to the joint venture of Mitsubishi Heavy Industries and Camponon Bernard, (2) Refrigeration Compressors and Gas Turbines to Elliott Company and General Electric respectively, (3) Main Cryogenic Heat Exchanger to Air Products and Chemicals Inc., and (4) Site Preparation work to Atlas Construction Co.

In parallel with these activities, starting in the second quarter of 1995, bid packages for the main EPC contracts were released to a prequalified slate of major international contractors. After completing the bid clarification process, the EPC contracts were awarded in March / April, 1996.

The contract for the Offshore platform facilities was awarded to the joint venture of McDermott ETPM East Inc. and Chiyoda Corporation; Saipem SpA was awarded the work for the subsea and onshore pipeline facilities. The EPC contract for the Onshore facilities was awarded to the joint venture of JGC Corporation and the M.W.Kellogg Company. Upon execution of the EPC Onshore contract, the four long-lead contracts were simultaneously assigned to JGC/Kellogg for single execution responsibility and coordination of the Onshore work.

For the first time in a project of this nature and size, RasGas required all Onshore EPC bidders to submit proposals to arrange financing of all costs associated with the Project. In employing this strategy, Contractors sought optimum sourcing of funds tied to their execution plans from export credit agencies, commercial banks, and other governmental and financial institutions.

The bidding and commercial strategies employed by RasGas have led to the timely execution of the EPC contracts to complete the work and deliver the first shipment of RasGas LNG by July, 1999.

RasGas Project Task Force teams are now located at the EPC contractors' offices in Yokohama, Houston, Milan, and Jebel Ali in U.A.E where engineering and procurement activities are progressing on schedule. Site preparation work is well advanced and civil and mechanical work for the LNG storage tanks is also on schedule. The installation of jacket structures for Wellhead platforms 1 and 2 has been completed, and drilling activities are scheduled to begin by the end of first quarter 1997.

In December 1996, RasGas finalised \$ 2.55 billion of loan facilities to finance its two train LNG project. Bank and Export Credit Agency loan facilities amounted to \$ 1.35 billion, with the remaining \$ 1.2 billion received in cash from the issue of bonds. The bond offering was the first capital market issue for an LNG project, the first debt offering for any Qatari entity and the first Middle East issue with a maturity beyond seven years. It is also the first project debt from the Middle East with a rating of A3 from Moody's and BBB+ from Standard and Poor's.

A summary of the project timetable is given in Figure 8.

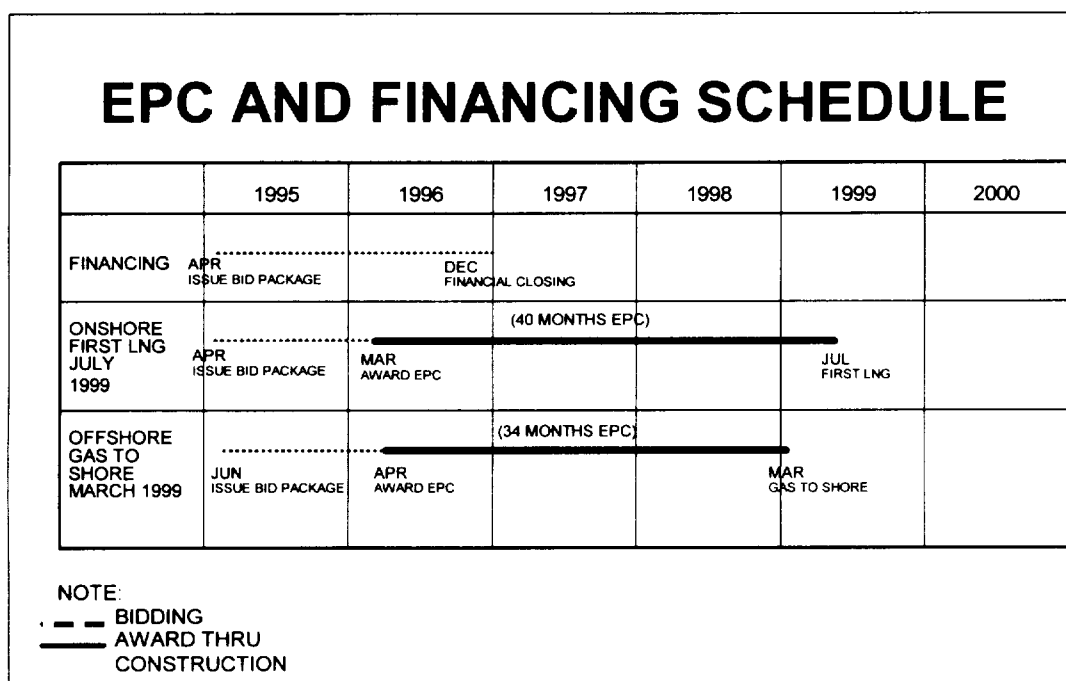


Figure 8

LNG Marketing

As previously mentioned, RasGas has already executed a Sale and Purchase Agreement with Korea Gas Corporation for delivery of 2.4 MMTA of LNG by mid-1999 and is continuing discussions/negotiations for additional supplies. In addition, RasGas is undertaking extensive marketing activities in Japan, Taiwan, China, Thailand, Turkey, India and other countries. The participation of Itochu Corporation and Nisso Iwai Corporation will reinforce RasGas marketing efforts, especially in the Japanese market which accounts for 75% of the world's LNG trade.

The market-driven approach employed by RasGas has tremendous flexibility in staging construction of incremental LNG capacity to ensure that supplies are available to buyers with optimal timing to satisfy their demand for LNG.

Summary

The Ras Laffan LNG Company has progressed significantly since early 1994 in bringing the vision of a world class multiple-train LNG project to the threshold of reality. The Company's market driven philosophy offers the flexibility to stage construction of additional trains to satisfy demand and long term growth requirements of its buyers with a "Real, Reliable and Renewable" supply of LNG.

- | | | |
|------------------|---|--|
| Real | - | The offshore Project area has been appraised and proven. The contracts are in place and work is on schedule for construction of the Onshore and Offshore facilities and first delivery of LNG by July, 1999. |
|
 | | |
| Reliable | - | The combined expertise of QGPC and Mobil in the Ras Laffan LNG Project assures security and reliability. Sustained equipment reliability has been a major criteria in the design of all facilities. |
|
 | | |
| and | | |
| Renewable | - | The giant North Field possess proven long term gas reserves and will allow LNG gas sales contracts to be renewed for many decades to come. |



“Middle East Gas : Prospects & Challenges”

Session (4)

Natural Gas Demand in the Far East / Prospects for Middle East Gas

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QA9700003

The Future of Middle East Gas In Japan

Mr. Yuzuru Aoki

Representative Managing Director

Tohoku Electric Power Co., Inc., Japan

ABSTRACT

1. Current state and outlook for LNG supply and demand in Japan

Supplies of LNG received in fiscal 1995 totaled approximately 44 million tons, a volume representing an increase of 3.1% from the previous year. Further increases in LNG imports are expected in the future as well owing to the importing of LNG from Qatar beginning in January this year.

According to "The Long-Term Outlook of Energy Supply and Demand in Japan," demand for natural gas is projected to expand from approximately 40 million tons in fiscal 1992 to 53-53 million tons in 2000, and then to 58-60 million tons in fiscal 2010.

2. Environment surrounding Japan's energy industries

With the global trend towards deregulation, it is inevitable that the electric power and gas industries will face a fiercely competitive environment and that larger economies than ever will be required for the procurement of fuel and materials. Unless LNG prices can be maintained at levels that permit it to compete with other fuels such as coal, LNG will lose its market competitiveness with respect to the electric power industry.

3. Outlook for Middle East gas in Japan

Middle East LNG will be a strong candidate to serve as a source of supply to Japan in the long term. The decisive factor in ensuring that LNG trade with Japan is brought about, however, will be the terms the sellers can offer with regard to three key points : economic efficiency, supply security, and supply/ demand matching.

In the future, it will be essential to ensure mutual understanding between the LNG sellers and buyers as well as to continue to step up mutual efforts to reduce costs.

The Future of Middle East Gas In Japan

Mr. Yuzuru Aoki, Representative Managing Director

Tohoku Electric Power Co., Inc., Japan

1. Current state of energy supply and demand in Japan

(1) State of Japan economy

The Japanese economy is said to have bottomed out and entered a recovery phase in October 1993.

Looking at recent economic trends described in the December 1996 monthly economic report of the Economic Planning Agency, we find that private demand is becoming firmer, backed by recovery trends in consumer spending and capital investment, and that the economic recovery is being sustained, albeit at a modest pace.

Japan's official discount rate has remained at an historical low of 0.5% since it was lowered in September 1995. In tandem with this relaxed credit climate, the Japanese government has been fostering deregulation and so forth with the aim of strengthening the economy's capacity for recovery and ensuring its sustainability, so as to achieve stable medium and long-term growth.

As regards forecasts for the economy in 1997, the Japanese government is projecting growth in real GDP of 1.9%, and the general view is that it will take some time before the economy achieves a full-scale recovery.

(2) Energy supply and demand

Final energy demand in Japan in the 1995 fiscal year rose by 3.2% from the previous year, boosted by factors such as the modest recovery trend by the economy, and colder weather than in the year before, which raised demand for heating and hot-water supplies.

As regards the supply of energy, total supplies of primary energy in fiscal 1995 was approximately 588 million kiloliters on a crude-oil-equivalent base, up by 1.9% from the previous fiscal year (Table 1). (The year-on-year rate of increase was 1.2% in fiscal 1993, and 5.4% in fiscal 1994.)

Broken down by energy source, supplies of oil fell by 0.4% from the previous fiscal year, as in spite of a rise in imports of petroleum products such as naphtha and kerosene, there was a substantial decline in supplies of crude oil for burning and C-grade heavy crude for use in power generation.

The supply of coal rose by 2.8%, owing to factors such as an increase in the supply of steaming coal for use in power generation.

Meanwhile the supply of nuclear power was up by 8.2%, as capacity utilization was at a high level, and new plant began operations (Tohoku Electric Power's Onagawa Nuclear Unit No. 2). This raised the proportion of total supplies provided by nuclear power to 12.0%, up from 11.3% in the previous fiscal year.

The supply of natural gas rose by 2.5% year-on-year, owing to an increase in imports of LNG. These imports come from the U.S. (Alaska), Brunei, the U.A.E. (Abu Dhabi), Indonesia, Malaysia, and Australia (Table 2).

Chubu Electric Power began imports from Qatar in January this year, and other Japanese buyers will also be receiving supplies from next year. The eight utilities (five power and three gas) plan to import an annual total of approximately 6 million tons from 1999.

(Supplies of LNG received in fiscal 1995 totaled 43.69 million tons, representing an increase of 3.1%, from 42.37 million tons in fiscal 1994.)

2. Environment surrounding Japan's energy industries

(1) Stimulating the principle of competition through deregulation

Amid the global trend towards deregulation, the energy industry is seeking to make thorough improvements in efficiency to a greater extent than ever before, while at the same time assuring the stability of supplies. There is a major trend in that direction, accompanied by developments such as the amendment of legislation.

With regard to the oil industry, to ensure more efficient energy supplies, last year the Provisional Measures Law on the Importation of Specific Petroleum Refined Products was repealed, and new oil-related legislation came into force in April.

As a result of the repeal of this law, anyone is now permitted to import products such as gasoline, on condition that they fulfill certain obligations with regard to storage and quality management. This is generating increasingly fierce competition, and oil companies are endeavoring to reduce costs by such means as exhaustive rationalization.

Turning now to the electric power industry, the Electricity Utilities Industry Law was substantially amended for the first time in 31 years, and the revised law came into effect in December 1995. The objective of this was to introduce competition into the

electric power industry and enhance its efficiency, premised upon the assurance of stable supplies of electric power.

Through the use of a tender system, it has also given independent power producers the opportunity of participating in the electric power market.

The results of the tenders held in fiscal 1996 were all made known in October last year, when it was revealed that decisions had been made on successful bids for power sources in a total of 20 cases with an aggregate capacity of approximately 3 million kilowatts, and that there had been fierce competition, with around four times as many bidders as contracts on offer.

In addition, a system of special electricity suppliers has been established, systematizing the supply of electric power within specified regions by such means as cogeneration.

Also, to stimulate competition, a new system of charges has been introduced in the form of a yardstick formula under which appraisals are made of the relative degree of efficiency, and then these are graded.

With respect to gas utilities, the Gas Utility Industry Law was partially revised and brought into effect in March 1995. The revisions to the law included the easing of regulations governing participation in the supply of gas to large-scale users, and regulations on gas charges. As in the case of the electric power

industry, the yardstick formula has also been introduced in the gas industry as a new charging system.

It is considered inevitable that electric power and gas utilities will face a fierce competitive environment, and as greater-than-ever economies will be demanded in the procurement of fuel and materials, the importance of the price competitiveness of fuel and materials is rising.

(2) Circumstances surrounding the LNG of electric power utilities

The basis of the makeup of power sources in the electric power industry is what is termed the best mix of power sources—determined by giving overall consideration to ensuring the stable supply of electric power and its economic efficiency, and using an appropriate combination of energy sources, without bias towards any particular sources. I believe that this policy will be maintained in the future.

Among the fuels used for power generation, it was formerly argued that LNG should be recognized as being a premium product with regard to the environment, on the grounds that it is environmentally superior to fuels such as coal.

Today, however, technical innovation has enabled coal-fired thermal power generation to be made considerably more

environmentally friendly, and it now seems impossible to acknowledge the superiority of LNG.

As a result, in the selection of fuel in the future, economic efficiency will be the most important prerequisite. Thus, as I mentioned earlier, the electric power utilities will find themselves in an extremely competitive environment, and unless LNG prices can be maintained at levels that enable LNG to compete with other fuels such as coal, which is now recognized as being economically efficient, LNG will lose its competitiveness in the market.

3. Outlook for LNG supply and demand in Japan

(1) Outlook for energy supply and demand in Japan

In June 1994 "The Long-Term Outlook of Energy Supply and Demand in Japan" was drawn up as the government's policy goal relating to energy supply and demand in Japan (Table 3).

Demand for natural gas for use in electric power generation and for town gas is projected to expand, rising from approximately 40 million tons in fiscal 1992, to 53-54 million tons in fiscal 2000, and then to 58-60 million tons in fiscal 2010.

The proportion accounted for natural gas is projected to rise steadily until fiscal 2000, but then to remain relatively static until fiscal 2010.

(2) Outlook for LNG supply and demand in the power business

According to the fiscal 1996 electric power supply plans filed by the electric power companies last year, the volume of demand for electric power in the 10 years to fiscal 2005 is projected to rise steadily at an annual average rate of 2%, buoyed by stable economic growth and by rising living standards.

As for the various categories of power-generation plant, over the 10-year period the capacity of plant for coal-fired thermal power is projected to double, and the quantity of power produced is set to rise at almost the same rate (tables 4 and 5).

As for oil-fired thermal power, although plant capacity will remain relatively static, the quantity of power produced is declining.

Plant capacity for LNG-fired thermal power is increasing, though the quantity of power produced is not expected to keep pace with capacity from fiscal 2000 to fiscal 2005, but to remain relatively unchanged.

The fact that there are such variations in these three categories of thermal power generation reflects the evaluation of

factors such as the economic efficiency of the fuel consumed by the different types.

With regard to LNG-fired thermal power, although plant capacity will increase, the capacity utilization ratio is projected to decline, owing to a change in the form of thermal power operation from conventional middle-load facilities to middle-peak facilities.

In addition, operations are expected to be highly efficient as a result of the replacement of LNG-fired thermal power and the bringing into practical use of new processes such as advanced combined-cycle power generation.

In view of these factors, it is thought unlikely that there will be an increase in the volume of LNG commensurate with the growth in demand for electric power, particularly from fiscal 2000 onwards.

(3) Outlook for LNG supply and demand in the gas business

According to supply-demand plans of town-gas companies, the number of users of town gas is estimated to increase at an average annual rate of 1.8% from fiscal 1996 to fiscal 2000.

In contrast, the volume of gas supplied is projected to increase at an average annual rate of 3.8% from fiscal 1996 to fiscal 2000, as there is expected to be an increase in demand for industrial use, where the basic units are large.

LNG used for the supply of gas totaled 11.67 million tons in fiscal 1995, and is projected to rise to 14.26 million tons in fiscal 2000, representing an average annual increase of 4.1%.

4. Outlook for Middle East gas in Japan

With regard to LNG produced in the Middle East, Japan has decided to take an annual total of 6 million tons on a plateau base from Qatar, in addition to LNG taken from Abu Dhabi.

I understand that other Middle East countries are planning LNG projects, though there are also LNG projects in various parts of the world outside the Middle East, for example the United States, Indonesia, Malaysia, Australia, and Russia, that are described as promising.

Corporate gas purchasers in Japan conduct comprehensive appraisals of each individual project, studying which project should become the LNG source for the company. These are the three most important points on which these appraisals focus.

The first is economic efficiency. That is, the securing of delivered prices in Japan that are competitive not only with LNG from other sources, but also with other fuels such as oil and gas.

Second, assuring security of supply over a long period.

It is essential not only to ensure the security of delivery by each tanker but to establish a long-term stable supply system. If a prospective place rich in LNG can meet these conditions, it will be highly appraised.

Third, the supply-demand matching of sellers and buyers during the startup period.

In future Japan-oriented projects it may be that the average procurement volume of LNG per purchaser will decline, while the number of parties involved increases. However, in that case it will be essential to act flexibly when coordinating the supply-demand timing during the startup period.

When Middle East LNG projects conduct their planning for sales to Japan, I believe that it is inevitable that they will compete with projects in Asia-Pacific countries and in other regions.

Aspects that could place the Middle East at a disadvantage are not only the region's long distance from Japan, but also the fact that one of the objectives of Japan's policy to move away from reliance on oil has been to endeavor to avoid the country's excessive dependence on the Middle East. In consequence, the basic policy of diversifying fuel supplies will be maintained, and it is possible that there will continue to be an attitude inclined towards curbing the proportion of supplies accounted for by the Middle East.

Middle East LNG will be a strong candidate for acting as a source of supply to Japan in the long term. However, to ensure that LNG trade with Japan is brought about, the decisive factor will be what terms the sellers can offer with regard to those three points that I have just referred to, namely economic efficiency, security of supply, and supply-demand matching.

As I have said, as the operating environment on the side of the buyers grows increasingly harsh, they are seeking even greater economic efficiency. In view of that, in future it will be essential to ensure mutual understanding of the standpoints of LNG sellers and buyers, and to continue to step up mutual efforts to reduce costs.

###

Table 1. Composition of supply of primary energy (Fiscal 1995)

	Volume : Crude-oil equivalent () : % share	Year-on -year change (%)
Total primary-energy supply	5 8 8	1. 9
Shares : Oil	(55. 8)	△1. 0
Coal	(16. 5)	2. 8
Natural Gas	(10. 8)	2. 5
Hydroelectric power	(3. 5)	22. 8
Nuclear power	(12. 0)	8. 2
Geothermal power	(0. 2)	56. 5
New energy, etc.	(1. 1)	4. 2

Table 2. Volume of LNG imports by Japan (Fiscal 1995)

Country	U.S. (Alaska)	Brunei	U.A.E. (Abu Dhabi)	Indonesia	Malaysia	Australia	Total
Volume (Thousand tons)	1,221	5,507	4,098	17,476	8,559	6,828	43,689

Table 3. Outlook for supplies of primary energy

	Fiscal 1992 [Actual]	Fiscal 2000 [Plan]	Fiscal 2010 [Plan]	Ave.year-on-year change (%)	
	() : % share			1992~ 2000	2000~ 2010
Total primary-energy supply [Million kl]	5 4 1	582~591	635~662	0. 9 ~ 1. 1	0. 9 ~ 1. 1
Oil [Million kl]	3 1 5 (5 8. 2)	308~316 (52.9~53.4)	303~331 (47.7~50.1)	Δ0.3 ~0	Δ0.2 ~0.5
Coal [Million tons]	1 1 6. 3 (1 6. 1)	130~134 (16.4~16.6)	134~140 (15.4~15.3)	1.4 ~1.8	0.3 ~0.4
Natural gas [Million tons]	4 0. 7 (1 0. 6)	53~54 (12.9~12.8)	58~ 60 (12.8~12.7)	3.4 ~3.6	0.9 ~1.1
Nuclear Power [Billion kwh]	2 2 3 (1 0. 0)	3 1 0 (12.3~12.1)	4 8 0 (16.9~16.2)	4. 2	4. 5
Hydroelectric power [Billion kwh]	7 9 (3. 8)	8 6 (3.4~3.3)	1 0 5 (3.7~3.5)	1. 1	2. 0
Geothermal power [Million kl]	0. 5 5 (0. 1)	1. 0 (0. 2)	3. 8 (0. 6)	7. 8	14.3
New Energy, etc. [Million kl]	6. 7 (1. 2)	12.1~9.4 (2.0~1.6)	19.1~11.5 (3.0~1.7)	7.7 ~4.3	4.7 ~2.0

Table 4. Plant Capacity [Unit : Million KW, () : % share of total]

	Fiscal 1995 [Actual]	Fiscal 2000 [Plan]	Fiscal 2005 [Plan]
Thermal power	118.16 (59)	140.13 (60)	165.51 (60)
LNG	43.54 (22)	58.19 (25)	69.08 (25)
Coal	20.14 (10)	28.69 (12)	42.24 (15)
Oil	49.53 (25)	48.19 (21)	48.05 (17)
Hydroelectric	41.99 (21)	45.04 (19)	52.09 (19)
Nuclear	41.19 (20)	45.08 (19)	55.79 (20)
Total	201.34	231.72	276.20

Table 5. Power output by type of plant [Unit : Billion kwh, () : % share of total]

	Fiscal 1995 [Actual]	Fiscal 2000 [Plan]	Fiscal 2005 [Plan]	Ave. year-on-year change (%)	
				1995 ~2000	2000 ~2005
Thermal power	478.0 (56)	524.7 (56)	570.5 (55)	1.9	1.7
LNG	191.0 (22)	241.4 (26)	243.9 (23)	4.8	0.2
Coal	117.2 (14)	147.7 (16)	207.0 (20)	4.7	7.0
Oil	150.9 (18)	113.3 (12)	97.5 (9)	△ 5.6	△ 3.0
Hydroelectric	85.4 (10)	96.5 (10)	101.3 (10)	2.5	1.0
Nuclear	291.1 (34)	313.0 (33)	361.1 (35)	1.5	2.9
Total	855.7	940.7	1,045.6	1.9	2.1



“Middle East Gas : Prospects & Challenges”

Session (4)

Natural Gas Demand in the Far East / Prospects for Middle East Gas

Paper No. (4-2)

Natural Gas Demand in the Far East

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“Middle East Gas : Prospects & Challenges”

Session (4)

Natural Gas Demand in the Far East / Prospects for Middle East Gas

Paper No. (4-3)

The Asia Pacific Gas Market- A Question of Balance

Russell Jacobs

**Vice President / Director, Purvin & Gertz,
U.S.A.**



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THE ASIA PACIFIC GAS MARKET:
A QUESTION OF BALANCE

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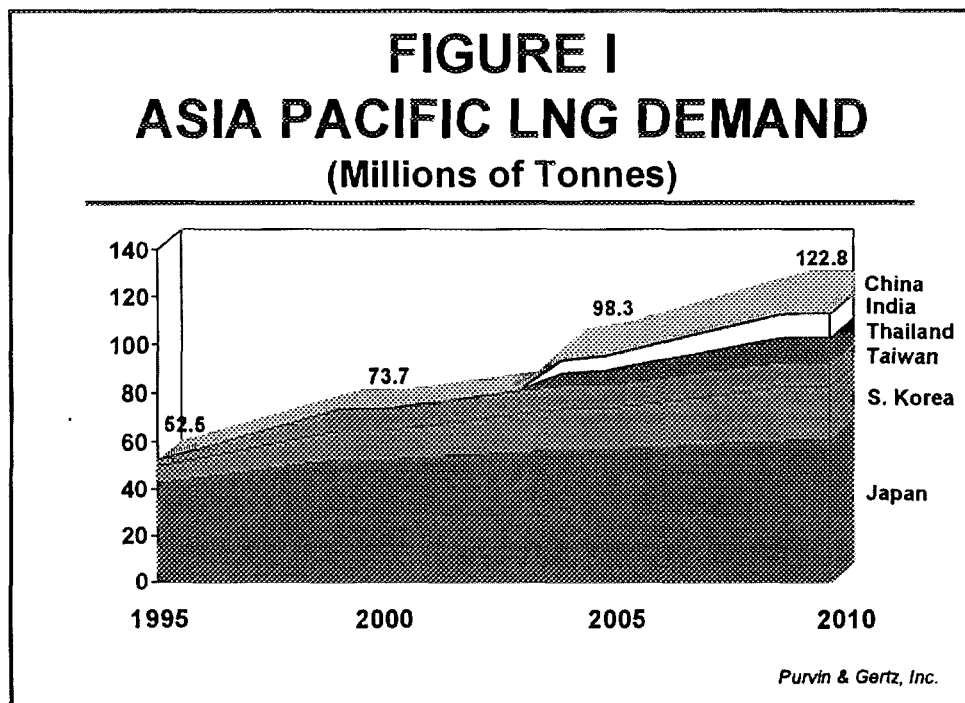
ABSTRACT

The underlying need for additional supplies of natural gas, both pipeline and LNG, will continue to expand in the Asia Pacific region. Spurred by expected development of LNG markets in Thailand, India, and coastal China, the demand for LNG could more than double by 2010. To meet the LNG needs of the future, numerous LNG grass roots and expansion projects are underway or firmly planned. Collectively, these projects could supply nearly 40 million tonnes of additional LNG by 2005-2010. If new geographical markets can not be developed (for whatever reasons) during this time frame, however, some currently planned projects could falter or be underutilized.

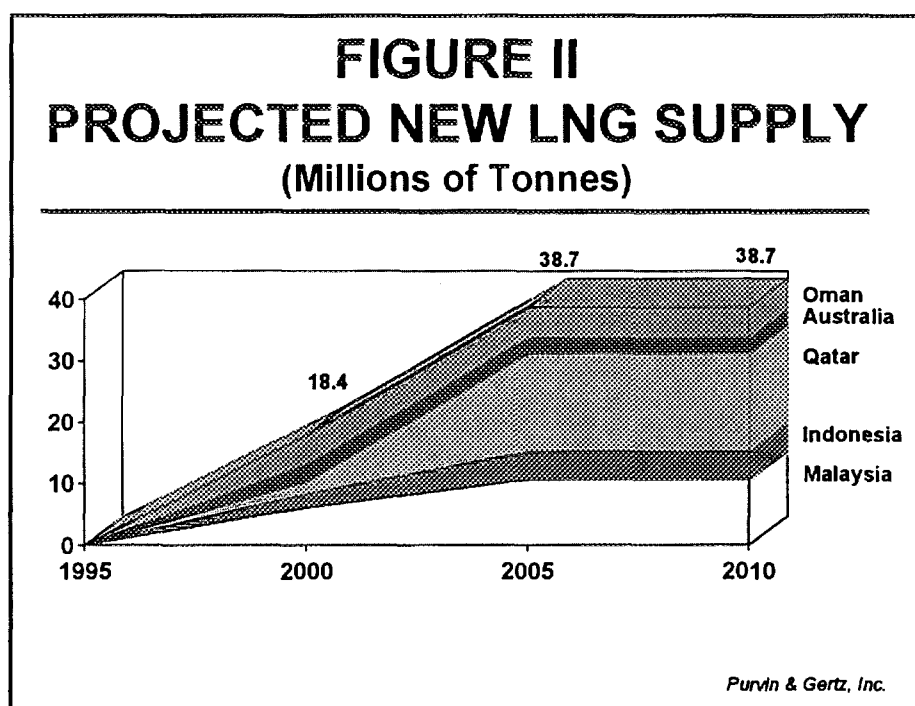
Factors that could delay development of new geographical markets for LNG include competition from pipeline gas projects, increased development and production of domestic gas reserves, economic viability, or political considerations. Structural changes within existing LNG consuming countries, such as a shift in new power generation demand from base load to middle or peak load fuel, could also adversely affect the balance between regional demand and supply capability. Underutilization of new plant capacity resulting from such imbalance would represent an additional driving force for growth in the emerging "spot" trade for LNG.

TEXT

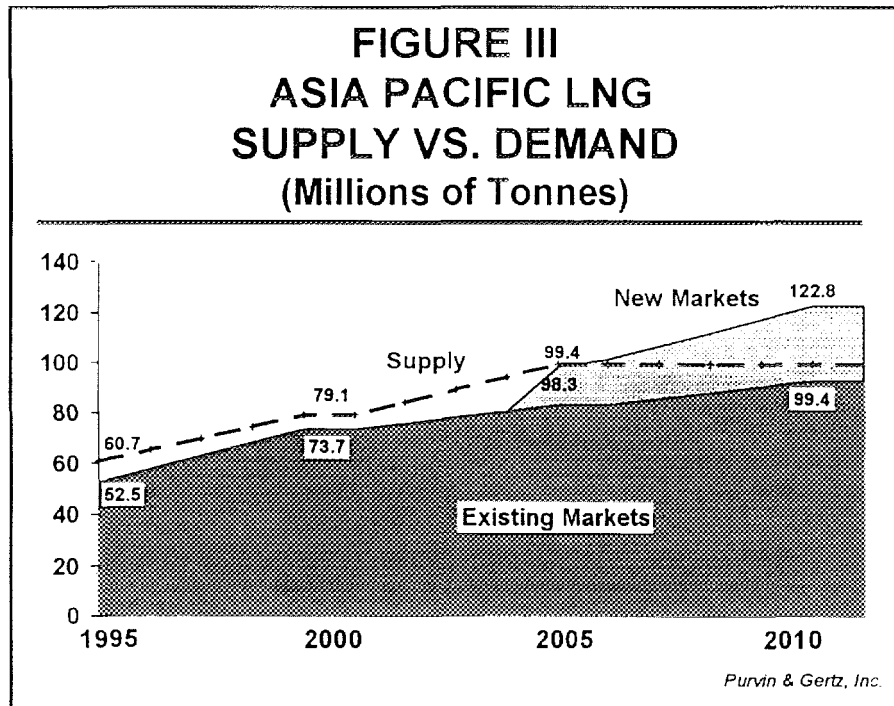
Despite economic uncertainties, the underlying need for additional supplies of natural gas (both pipeline and LNG) will continue to expand in the Asia Pacific region. Spurred by expected development of LNG markets in Thailand, India, and coastal China, the demand for LNG could more than double by 2010 (Figure I).



To meet these LNG needs of the future, numerous grass roots and expansion projects are underway or firmly planned from Malaysia (MLNG 3), Indonesia (Badak), Australia (N.W. Shelf), Qatar and Oman. Collectively, these projects could supply nearly 40 million tonnes of additional LNG by 2005-2010 (Figure II).



If these views of both demand and supply become reality, the international LNG community not only welcomes new Middle East suppliers over the next decade, but the opportunity for longer term project development remains considerable. Tipping the scales in the other direction, however, if new geographical markets cannot be developed (for whatever reasons) during this time frame, some currently planned projects could falter or be underutilized (Figure III).



Factors that could delay development of new geographical markets for LNG include competition from pipeline gas projects, increased development and production of domestic gas reserves, economic viability, or political considerations. The need for LNG in Thailand, for example, could be replaced by potential pipeline gas imports from Natuna Island or Viet Nam.

The balance between regional demand and supply capability could also be adversely affected by structural changes in gas use within existing LNG consuming countries. In the power generation sector, for instance, combined cycle gas turbine plants adjust easier to daily, or even hourly, variations in electricity demand. As a result, growth in LNG demand for power generation may be more closely related to middle and peak load use than base load fuel. Should this occur, not only may demand growth be lower on an annual basis, but greater flexibility in LNG purchasing practices would be advocated, if not demanded, by buyers.

If the LNG supply/demand picture of the next decade does lead to underutilization of new plant capacity, the imbalance will represent another driving force for growth in the emerging "spot" trade for LNG. Starting from virtually nil in 1992, spot cargoes have reached over 3% of total LNG trade in recent years. This activity has established at least some degree of structure for spot trading arrangements, although no international LNG reference price presently exists to facilitate individual LNG spot sales transactions. Growth in the spot LNG market over the next decade will inevitably lead to greater supply flexibility for middle and peak load power generation, new independent power projects, and perhaps other end use sectors as well. How this flexibility develops will have a considerable influence on the structure of the Asia Pacific LNG market in the early years of the next century.



“Middle East Gas : Prospects & Challenges”

Session (4)

Natural Gas Demand in the Far East / Prospects for Middle East Gas

Paper No. (4-4)

Natural Gas Demand Prospects in Korea

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QA9700005

Natural Gas Demand Prospects in Korea

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Abstract

Korea's natural gas demand has increased enormously since 1986. Natural gas demand in Korea will approach to 29 million tonnes by the year 2010, from little over 9 million tonnes in 1996. This rapid expansion of natural gas demand is largely due to regulations for environmental protection by the government as well as consumers' preference to natural gas over other sources of energy. Especially industrial use of gas will expand faster than other use of gas, although it will not be as high as that in European and North American countries. To meet the enormous increase in demand, Korean government and Korea Gas Corporation (KOGAS) are undertaking expansion of capacities of natural gas supply facilities, and are seeking diversification of import sources, including participation in major gas projects, to secure the import sources on more reliable grounds.

1. Introduction

Natural gas demand in Korea has come through an enormous expansion. Total demand for natural gas in Korea is estimated to be 9.3 million tonnes in 1996. The average annual growth rate of the demand until 1996 is 67.7% per annum, since 1986 when natural gas was first imported. Initially, natural gas was brought in as an alternative source of energy to strengthen the nation's energy security and stability. However, increasing regulatory actions for environmental protection, a steady economic growth and user preference to gas over other forms of energy have all contributed to the acceleration of demand increase afterwards.

The environmental regulation is expected to become tougher, especially as Korea was accepted as a member of OECD last year, in the midst of so much talks about the Green Round trade negotiations and the need for strategies to accommodate them. This situation may lead Korea's gas consumption to even more increase. Current forecasts for natural gas demand are 20.2 million tonnes and 28.5 million tonnes in the year 2001 and 2010, respectively. These estimates reflect a consistent growth of natural gas demands in the coming years, largely due to the rapid increase in industrial use of natural gas after completion of nation-wide gas pipelines which connects almost all the corners of the country.

2. The natural gas market in Korea

Before a discussion of natural gas demand in Korea, it is worthwhile to note the market situation of Korea briefly. In Korea, natural gas was first imported as an alternative energy source for power generation in 1986. The gas demand for power generation has expanded rapidly as the demand for electricity soared up in the late 80's and the early 90's. While the gas demand for power generation has been increasing, Korean government decided to supply natural gas to the general public to meet the growing needs of clean energy. Currently, Korea Gas Corporation (KOGAS) is responsible to import and transmit the natural gas in the country via the nation-wide transmission pipelines.

Power plants owned by Korea Electric Power Corporation (KEPCO), receive gas directly from the KOGAS' transmission lines, whereas domestic needs are supplied by the local distribution companies (LDCs). LDCs that are located within the service region of KOGAS pipelines buy natural gas from KOGAS, then redistribute it to end-users using their own distribution lines, while the other distributors which are not in the service region, distribute the petroleum gas to their customers. As of 1996, there are 32 local distributors in Korea, among which a total of 15 local distributors are engaged in distributing natural gas to residential, commercial and industrial gas premises, while

the others are distributing petroleum gas which will be replaced to the natural gas as the nation-wide pipelines expand.

The total length of the trunk lines is 1,334 km as of the end of 1996, which will be extended to 2,313 km by the year 2006 and expand further as the gas demand increases. As KOGAS expands its gas pipelines, most parts of the country will come into KOGAS' service area by 1999 according to its plan. Currently, natural gas service regions include two-thirds of the whole nation - the northern and the central parts of the country; and are being expanded toward the southern areas.

3. Natural gas as a source of primary energy

Total primary energy demand in Korea was 150.4 million toe in 1995, which is now forecasted to be 287.5 million toe in 2010 as shown in Table 1 below. According to Korea Energy Economics Institute, the primary energy demand is predicted to increase at 4.4 % per annum in the period between 1995 and 2010. Compared to the national income growth rate of 6 % per annum over the same period, the predicted pace of growth in the energy demand is relatively low, and the energy intensity, the ratio of total primary energy to GNP, will be improved substantially during the period. However, natural gas supply as a primary source of energy will grow from 9.2 million toe in 1995 to 34.8 million toe in 2010 - the annual growth rate of 9.3 %, thanks to the more toughening environmental protection measures by government and public desire to use the clean energy. Therefore, the share of natural gas among the primary energy needs would expand up to 12.1 % in 2010 and in 2020 from about 6 % in 1995.

Table 1. Outlook on primary energy demand in Korea

mtoe, %

	1995		2001		2006		2010		2020	
Oil	94.0	62.5	119.7	55.0	134.3	51.9	147.5	51.3	178.1	50.7
LNG	9.2	6.1	24.8	11.4	30.3	11.7	34.8	12.1	42.5	12.1
Coal	28.1	18.7	43.1	19.8	54.1	20.9	52.9	18.4	61.8	17.6
Hydro	1.4	0.9	1.7	0.8	1.3	0.5	1.4	0.5	1.8	0.5
Nuclear	16.7	11.1	25.5	11.7	34.7	13.4	45.7	15.9	58.7	16.7
Renewable	1.1	0.7	2.8	1.3	4.1	1.6	5.2	1.8	8.4	2.4
Total	150.4	100.0	217.7	100.0	258.7	100.0	287.5	100.0	351.2	100.0

Source: Korea Energy Economics Institute, 1996

Nonetheless, natural gas share to the total energy needs in Korea is far below the average of its share in other major industrial countries. In 1995, major countries supply 20 to 50 % of their primary energy needs with natural gas depending upon their gas resource abundance: Russia 51 %, United States, Canada, United Kingdom and Italy showed approximately 30 %, and France and Japan were 13 % and 11 % respectively (see Table 2). Thus, in terms of natural gas share to the total primary energy, Korea would be in a similar status to those of Japan or France in the year 2010.

Table 2. Primary energy consumption in the major countries

mtoe, %

	Oil		Natural Gas		Coal		Nuclear		Hydro		Total	
U.S.A	807	39	560	27	494	24	183	9	26	1	2070	100
Canada	80	35	67	30	25	11	25	11	29	13	226	100
U.K.	82	37	66	30	48	22	23	10	1	1	220	100
France	89	37	30	13	13	6	97	41	7	3	236	100
Germany	135	39	67	20	93	28	40	12	2	1	337	100
Italy	95	62	43	28	11	7			4	3	153	100
Russia	146	23	318	51	119	19	26	5	15	2	624	100
Japan	267	54	55	11	86	18	74	15	8	2	490	100
Korea	95	64	9	6	27	18	17	11	1	1	149	100

Source: BP Statistical Review of World Energy, 1996

4. Outlook for natural gas consumption in Korea

Total natural gas demand in 1996 is estimated to be 9.3 million tonnes in Korea. The volume of gas consumption will increase to 20.2 million tonnes in year 2001 based on a conservative forecast. The growth rate is 16.7 % per annum between 1996 and 2001. A major reason for the increase in demand for this period is the expansion of gas pipelines, in the atmosphere of growing public concern on environmental protection, particularly as Korea has joined recently the advanced country's club - OECD. As mentioned before, the customers who are provided with the petroleum gas by the local distributors that are as yet unconnected to KOGAS' transmission lines will switch their services to the natural gas after KOGAS' pipelines reach through their regions around 2000. After completion of KOGAS' nation-wide gas pipelines, the growth rate of gas consumption will be slowed as can be expected naturally. Natural gas demand will

grow 3.9 % on average annually from 2001 to reach 28.5 million tonnes in 2010 as shown by the forecast (see Table 3).

Table 3. Outlook on natural gas demand by user sector

thousand tonnes, %

	1996*		2001		2006		2010		Annual Growth Rate	
									'96-'01	'01-'10
City Gas	4,809	51.5	11,492	56.9	15,275	62.6	17,519	61.4	19.0	4.8
• Residential	3,130	33.5	7,426	36.7	9,965	40.8	11,459	40.1	18.9	4.9
• Commercial	906	9.7	1,765	8.7	2,306	9.4	2,655	9.3	14.3	4.6
• Industrial	773	8.3	2,301	11.4	3,005	12.3	3,405	11.9	24.4	4.5
Power Generation	4,527	48.5	8,719	43.1	9,116	37.4	11,028	38.6	14.0	2.6
Total	9,336	100.0	20,211	100.0	24,391	100.0	28,547	100.0	16.7	3.9

* Figures in the column of 1996 are preliminary estimates.

Alternative forecasts may possibly be made depending on developments of gas projects considered currently. KOGAS is considering to participate in several gas projects in collaboration with other Korean companies to meet the growing needs of gas in the economy and to diversify the source of gas import. One of the project considered positively is a pipelined natural gas project connecting gas pipelines from a gas field in the eastern part of Russia to Korea through Mongolia and China. If it is successfully proceeded, KOGAS will supply pipelined natural gas along with the liquefied natural gas (LNG). Thereby KOGAS would be able to reduce the cost of service for supply and the service rate of gas. A substantial reduction of gas rate would change the structure of energy consumption in Korea. Because all the natural gas supplied in Korea has been imported in the form of LNG, mostly from the South-East Asia, natural gas price is relatively higher than those of competitive sources of energy such as oil. If Korea can deploy the low priced gas such as pipelined natural

gas as like European countries, it may induce new usage of gas, and the demand for natural gas could increase even more than expected currently.

5. Outlook on natural gas demand by user sector

To see the gas demand by user-sector, a major sector for natural gas consumption in Korea is the power generation sector. In 1996, power generation consumed 4.5 million tonnes of natural gas, which was 48.5 % of total gas consumption, while the city gas for domestic gas needs consumed 4.8 million tonnes of gas, whose share to the total gas consumption was 51.5 %. As the gas industry in Korea being matured, domestic needs of natural gas increase faster than the needs for power generation. Hence in 2010, the share of gas used in the power generation will shrink to about 38.6 %, while the share of city gas will grow up to 61.4 % of the total gas demand.

Within the city gas sector, the main area for gas is the residential use, where the natural gas is mostly used for heating and cooking. The residential sector consumed 3.1 million tonnes of natural gas in 1996 and will consume 11.5 million tonnes in 2010 - share to the total gas consumption will be 40.1 %. The increase in gas demand in the residential sector can be explained by two facts in the coming years. First, as the steady increase in household living standard continues, many consumers switch the source of heating and cooking energy to natural gas because they prefer the cleanness and convenience of gas, even though the price of gas is relatively expensive in Korea. Second, many residential complexes have to modify their heating system to be able to use natural gas. This is because most of central heating system in apartment complexes in urban areas must meet the environmental regulation set by the government.

A focus must be given to the industrial use of gas to overview the prospect of gas demand in Korea for the future. Industrial sector consumed 773 thousand tonnes of natural gas in 1996, which is only 8.3 % of the total gas consumption in the year. Though it is classified as the industrial demand, so far a majority of the gas consumed in the industrial sector is for heating, cooling as well as cooking in factories rather than a

use in manufacturing processes of the production lines. As gas-firing equipment for production processes are introduced for practical use as gas industry continues to grow, many industrial fields such as iron and steel industry and ceramic industry are expected to see more of their production facilities incorporate gas-burning equipment because the regulation of air pollution on the use of energy in the industrial sector will be reinforced in the coming years. In the period between 1996 and 2001 when the construction of nation-wide gas pipelines is completed, the demand for gas in the industrial sector may be increased to 24.4 % per annum and after completion of the pipelines, the demand will increase 4.5 % per annum. Therefore, a total of 3.4 million tonnes of natural gas is expected to be consumed in 2010 and the share of gas in this sector would be increased to 11.9 % of the total consumption, by the current forecast.

Gas demand for heating, cooling and cooking in hotels, restaurants, or office buildings is classified as the commercial use of gas. In 1996, a total of 906 thousand tonnes of natural gas was consumed in the commercial sector. Gas consumption in the commercial sector will increase to 2.7 million tonnes in 2010, which is 9.3 % of the total consumption in the year 2010.

Comparing the structure of gas demand by sectors with major countries in the world as shown Table 4, it is seen that many advanced industrial countries in North America and Europe consume a large amount of natural gas in the industrial sector and residential / commercial sector, while Korea and Japan, in which most of natural gas are imported from abroad in the form of LNG, consume most of natural gas for power generation and residential / commercial uses. In Japan and Korea, the cost of service for distributing natural gas is relatively higher than in other countries, and natural gas is expensive compared to oil which is a close substitute for an industrial energy source. As long as Japan and Korea supply only LNG for their gas services, it can be expected that the industrial share of gas consumption will remain limited because of the poor competitiveness in price against other sources of energy for the industrial sector.

**Table 4. Share of natural gas consumption by sector
in major industrial countries**

%

	Power Generation	Industrial	Residential/ Commercial	Raw Material /Others
U.S.A.	14	45	38	3
Canada	6	44	42	8
U.K.	15	25	54	6
France	2	35	56	7
Germany	16	40	44	0
Italy	20	36	42	2
Russia	36	44	17	3
Japan	70	11	19	0
Korea	53	5	42	-

Source: Cedigaz and KOGAS, 1996

- Figures are of 1995 for Korea, of 1994 for the others.

6. Outlook on natural gas import

Showing diversified import origin, KOGAS brought in 9.6 million tonnes of LNG in total in 1996 from four countries: Indonesia, Malaysia, Brunei and Australia. Until 1993, Korea depended for its import source on Indonesia and Malaysia only. In order to diversify the LNG sources, KOGAS signed new long-term Purchase contracts with Qatar and Oman, from which the delivery of gas will start in 1999 and 2000, respectively.

For the supply of short and medium-term demands that are not covered by the long-term contracts, and at the same time, from new projects such as Canadian Pac-Rim LNG Project which is now under negotiation. Looking after even long-term security of supply sources, pipeline gas imports such as from Russia are also examined positively.

Russian pipe line project is under pre-feasibility study, to import natural gas from there in the late 2000', and feasibility study will follow soon when the result being confident.

Table 5. Current and future LNG Imports

thousand tonnes, %

	1996		2001		2006		2010	
Total Import	9,595	100	20,717	100	25,011	100	29,316	100
Contracted(Total)	9,595		13,700		13,760		11,460	
- Indonesia	6,262	65	5,300	26	5,300	21	3,000	10
- Malaysia	2,527	27	2,000	10	2,000	8	2,000	7
- Qatar			2,400	12	2,400	10	2,400	8
- Oman			4,000	19	4,060	16	4,060	14
- Australia	56	1						
- Brunei	705	7						
To be secured			7,017	33	11,251	45	17,856	61

7. Concluding remarks

Natural gas consumption in Korea has been and will be expanding due to a combined stimulant of environmental regulations, convenience of natural gas use and improvement of standard of living. Since the beginning of natural gas use in 1986, natural gas consumption has grown at 67.7 % per annum until 1996. More upgraded environmental regulation and expansion of national gas pipelines may bring about an even further increase in natural gas demand, a new acceleration taking place in the

industrial sector. After completion of national gas pipelines, pace of increase in demand will be lowered somewhat. On a baseline forecast, natural gas demand in Korea will reach around 29 million tonnes in year 2010, about 3 times more than current consumption and the share of natural gas among the total primary energy needs will be about 12 %, which would be similar to those of Japan or France of 1995. However, a successful execution of pipelined gas project under consideration may give an opportunity for further growth in all demand in sectors of gas consumption.

Even though continued strong growth in demand may provide with a vibrant source of great opportunity to the players in the industry, a number of challenges must be overcome in order to take full advantage of the opportunity. These include: the increasing difficulty in siting new supply facilities; the ways to improve the efficiency of supply facility utilization; the need to develop safety technology and environmental measures that are to be practically used; and the need to secure import sources on a stable contract basis.

In the face of these tasks, Korean government and KOGAS are determined to reinforce supply capability by constructing a new receiving terminal and more storage tanks on one hand, as well as to improve the security of supply sources on the other hand. For the latter, policies like import source diversification as well as participation in gas projects, and demand-side management of gas market are also pursued.

**SECOND DOHA CONFERENCE
ON NATURAL GAS**
March 17 - 19 , 1997
DOHA - QATAR



مؤتمر الدوحة الثاني للغاز الطبيعي
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الدوحة - قطر

“Middle East Gas : Prospects & Challenges”

Session (4)

Natural Gas Demand in the Far East / Prospects for Middle East Gas

Paper No. (4-5)

Natural Gas Utilization in Taiwan

H. C. Chang
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“Middle East Gas : Prospects & Challenges”

Session (5)

Natural Gas Demand in Europe / Prospects for Middle East Gas

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“Middle East Gas : Prospects & Challenges”

Session (5)

Natural Gas Demand in Europe / Prospects for Middle East Gas

Paper No. (5-1)

Prospects For Middle East Gas in Europe

Michael Tusiani
Chairman and Chief Executive Officer,
Poten & Partners
U.S.A.



“Middle East Gas : Prospects & Challenges”

Session (5)

Natural Gas Demand in Europe / Prospects for Middle East Gas

Paper No. (5-2)

The Future of Middle Eastern Gas in Europe

Domenico Dispenza
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THE FUTURE OF MIDDLE EASTERN GAS IN EUROPE

By

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Italy

One of the European natural gas industry's goals is to make Middle Eastern gas a substantial additional source of European energy supplies.

However, the Region's abundant gas reserves, which justify our optimism, have always had to cope with the even greater quantity of oil which can be extracted at particularly low cost compared with other production areas.

I suggest that to outline how Middle Eastern gas could contribute to the energy requirements of Western and Central Europe, from the Atlantic to the borders of the CIS, we should start with ENI's analyses of consumption, based on forecasts carried out by some of the most authoritative international centres.

Figure number 1 shows natural gas consumption developing strongly up to the second energy crisis. From 1960 until 1980 growth was around an average of 14% per annum.

It is well known that the end of the sixties marked a major transformation in the gas industries of the whole of Europe, which responded effectively to a strong upturn in domestic demand by setting up major import projects, either via pipeline or in the form of LNG.

By the eighties, however, the major consumer markets for natural gas in Europe had matured and settled at a level which I would call 'dynamic', with annual growth stabilising at around 1.8% over the '80-'95 period. Although this may be considered moderate for the gas sector, it is almost double the growth in overall energy demand of around 1%.

In the five years up to the year 2000 growth for natural gas will accelerate slightly to about 3.5 % per annum, then fall to 2.2% in the decade 2000-2010 and to 1% in the following decade 2010-2020.

If we go on to analyse the European region by degree of development of the natural gas market (fig. 2) we see that towards the year 2010 the mature markets will reach their point of maximum expansion and in the decade that follows they will remain practically stationary.

The developing markets, however, will continue to grow until 2020 and maybe even beyond. To be more precise, forecasting experts envisage substantial expansion over the coming 15 years, which by 2010 will more or less double the size of the natural gas market in these countries as a whole, compared with today, and average growth will be 4.5% per annum.

In the decade which follows, the expansion of natural gas will decrease, even in this developing area. But this will give an average growth figure

of around 3% per annum, which shows that natural gas will still be in a healthy position for the next twenty-five years and beyond.

The overall picture of final demand for natural gas (fig. 3) shows a residential sector which is set to increase by around 50 bcm in the next 15 years ('96-2010), which means an average annual increase of 1.5%. The decade after that will be more or less stationary.

According to these estimates, the industrial sector, too, will have the same percentage growth (+1.5% or so), whilst in absolute terms there will be an increase of around 30 bcm over the entire period in question. From 2010 to 2020, though, almost complete saturation is expected.

The sector which will put the most pressure on gas energy and makes it most difficult to identify possible developments in demand is, as we all know, the electricity generation sector.

Some countries abandoned nuclear power quite a while ago; others have cut development, whilst others have decided that when the old reactors reach the end of their lives, new ones will not be built.

As far as coal for electricity generation is concerned, conditions do not suggest significant developments, especially in the near future. There are some opportunities in the more distant future, thanks to expected technological developments in this sector.

Public opinion still shows a strong, deep-rooted opposition to large coal-fired power stations, opposing their construction and use under the guise of respect for and preservation of the environment.

The lack of certainty in planning and construction in this sector makes it difficult to forecast the real long-term demand for gas in the electricity generation sector. The experts we have taken as our starting point for this information and these ideas have suggested that in the next few years up to 2000 development will be running at the spectacular average level of about 8-9% per annum.

As a result of the uncertainties referred to earlier, forecast demand for gas in the electricity generation sector covers a range of possibilities, with a difference of 80-90 bcm per annum between the maximum and minimum estimates by the end of the period.

Comparison of supply and demand for natural gas in Europe (fig. 4) shows a rapid fall-off in their relationship, with resulting differences in the curves concerned. On the supply side there is a progressive fall in local production, which is only partly made up for by the growth in forecast planned imports, which experts estimate as growing until 2010 and then stabilising at those levels.

However consumption develops, the supply gap will already exist by the year 2000, going on to reach ever higher levels; towards 2020 a supply deficit of 150-250 bcm per year is expected.

The enormous potential of the Middle East enables me to safely say that from the next decade onwards Europe will also have room for gas from this production area.

I believe that this gas has everything it needs to compete with North Sea gas, for which production costs have a very different effect on price.

The same goes for Siberian and North African gas, although here it is a matter of transport costs to the European consumer markets.

These three major areas of production, which are Western Europe's traditional sources of supply, will be able to increase their imports, but will not be completely able to fill the gap referred to above.

Middle Eastern gas will be able to reach European markets in a number of different ways.

It has been suggested that the gas could be transported overland (fig. 5) to an eastern Mediterranean port where it could be liquefied for sea transport to a wide range of destinations.

There are also feasibility studies for major gas pipelines which could carry natural gas from the Middle East to the heart of Europe via Turkey and the Balkans. The regions to be crossed are increasing their natural gas market and the countries of central Europe need to further diversify their sources of supply.

Eastern Europe will also require Middle Eastern gas when domestic production starts to near exhaustion and the traditional exporter countries such as Norway and North Africa will have to reduce supplies.

On the European scene this just leaves Russia, with its immense gas fields, but it will presumably be difficult for the Russians alone to supply the growing demand of an entire continent.

The consumer countries will have to start to look further afield to increasingly distant areas (fig. 6) for new international suppliers who, in

promoting the diversification of supply, will be required to guarantee the security and cheapness of the whole of Europe's gas system.

There are many solid prospects for development of gas projects in the Middle Eastern area. It must always be borne in mind that natural gas must reach the consumer markets at a competitive price, regardless of its place of origin.

With this aim, we operators in this sector have to draw on past experience as we are called to identify new forms of cooperation which, with technical, commercial and financial innovations, open the way for new gas projects ever better suited to the demand for this type of energy in Europe.

Cooperation will take the form of collaborations between potential purchasers, to make the most of the advantages inherent in large projects. It will also be necessary for all contracting parties at each stage of the chain, from production to transportation of the gas, to be more fully involved in order to share the risks more evenly.

The complex natural gas chain, from upstream to downstream, has its own special characteristics which are not found in other energy sectors. Unlike the oil chain, gas poses ongoing long-term commercial and financial problems which make it a complicated matter to balance the different interests involved.

On the final markets natural gas must be competitive with other energy products which could substitute it. The high transport and distribution costs make it difficult to achieve this balance.

Present international trade in natural gas has been set up and developed following acceptance of these characteristics of natural gas by all parties involved in the different stages of the business, including the producer states and the countries crossed by the transportation structures.

Royalties, transportation costs and all the associated expenses have been and must continue to be balanced against and suited to the particular demands of international supplies.

After coal, which assisted the first stages of industrialisation in the more developed countries, came oil, which powered the more advanced industrialisation of the post-war period after 1945.

Today we are in the era of natural gas, which has carried and continues to carry us towards a better quality of life, not just in the industrialised world, but also in the developing countries where natural gas can make a major, rapid contribution to the reduction and closure of the gap which separates these countries from the others.

BIOGRAPHY

Domenico Dispenza is Director of Gas Supply at Snam SpA, Milan. In addition, he is Managing Director of Promgas, a joint venture between Snam and Gazprom of Russia.

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“Middle East Gas : Prospects & Challenges”

Session (5)

Natural Gas Demand in Europe / Prospects for Middle East Gas

Paper No. (5-3)

Natural Gas Demand Prospects in Europe

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Session 5: Natural Gas Demand Prospects in Europe

"Outlook for Europe"

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I. Introduction

The outlook for gas is favourable. According to demand forecasts, gas will remain an attractive energy source for European supplies. There are of course considerable uncertainties about gauging the actual volume trend, even though a suspicious degree of consensus exists among various institutions on the anticipated development. But we all know that forecasts were wrong all too often. The influencing factors are unpredictable such as : environmental behavior and constraints, economic growth, energy taxation, liberalisation or regulatory tendencies, emergence of new markets in southern, central and eastern Europe and the like.

II. Demand Picture

In the European energy mix, natural gas is today the fastest growing energy. Forecasters see demand in western Europe rise by almost a third to 350 - 370 mtoe in 2005, or by 40 % to 370 - 390 mtoe in 2010, respectively. The power generation and residential/commercial sectors are seen as the main areas of growth. Geographically, major growth is expected to occur primarily in Italy and the UK, each accounting for nearly a quarter of the rise. Germany, Spain and France account for a further 28 % of the increase. In other words, these five countries represent more than $\frac{3}{4}$ of the demand rise of about 110 mtoe anticipated up to 2010.

In the next few years, European demand is well covered by volumes from indigenous production and by imports already contracted. Leaving aside the quantities currently offered on the purchasing market, there is in purely mathematical terms a gap of only 2 %. In 2010, however, there is room for new supplies of approx. 12 % of anticipated demand, or about 47 mtoe in absolute terms.

This development in western Europe is, however, characterised by geographical differences. While north-west European gas industries have already attained a high market penetration in the energy mix, there is still considerable demand potential for some southern European gas industries (e.g. in Italy and Spain). And, future demand is already covered to a greater extent in north-western continental Europe than in southern Europe.

This was the picture at the end of 1996 - recently negotiated contracts for gas from Norway, Russia, the UK and Netherlands may call for a reassessment, if and when confirmed.

III. Supply Options for Continental Europe

Additional supply potential for continental Europe is determined by the questions: Which producers are creating new supply options for this market, and what additional quantities might be available and for which period ?

1. United Kingdom

Despite steeply rising consumption in the UK, production capacity is clearly in excess of domestic requirements. An export potential of some 8 to 15 billion m³ annually is anticipated for a period of seven to ten years once the Interconnector is in operation by 1998, as scheduled.

2. Norway

Norway has already agreements in place with its continental European customers that will more than double its deliveries. Some 60 billion m³ annually have been contracted for the period from about 2005 onwards. With its offshore pipelines to the Continent, Norway will possess offshore transport capacity of 75 billion m³ a year from 1999 onwards. Annual output could be raised well beyond the contracted volumes to a level of approx. 80 billion m³.

3. Russia

Russia with 35 % of the world's gas reserves has a huge potential for additional supplies to north-western Europe.

In the long run, the new transmission system from the Yamal peninsula may deliver some 50 billion m³ to western Europe annually, and a further 14 billion m³ a year to Poland.

4. The Netherlands

The Netherlands has returned to the market with a new export initiative of approx. 240 billion m³, on the basis of indigenous reserves as well as additional imports from Russia, the UK and Norway.

5. Algeria

Algeria's total gas exports will rise from about 42 billion m³ in 1996 to some 60 billion m³/a before the end of this century, with over 50 % of it being piped gas via Tunisia, the Sicilian Channel to Italy and the new route via Morocco, the Strait of Gibraltar to Spain and Portugal.

There is great potential for even more Algerian gas supplies to Europe.

6. New Sources

Nigeria and Trinidad will join the suppliers' league by the turn of the century, while the big export potentials from the Middle East may be mobilized towards Europe after that date.

7. Implications

With the new projects and the new gas volumes, a comfortable supply situation is emerging for continental Europe. Nonetheless, the additional gas supplies from various regions are marked by different characteristics:

- UK gas deliveries are likely to occur only for a limited period.
- The Netherlands is primarily seeking to stabilise its absolute supplies with the additional volumes.
- Norway, Russia and Algeria have a large reserve base for future, long-term gas production and possess capacity for additional production and for transport.

The total volume potential available on the upstream side may result in an oversupply in north-western Europe. But this is only of a temporary nature. After 2010 a gap will arise, even if all supply options currently offered are exploited.

IV. Sales Side

What implications will the pressure of additional volumes have on the demand side ?

Primary energy consumption in western Europe as a whole will rise by about 14 % in 2010. Natural gas will be the winner, with a PEC share expanding to 24 % by gaining further shares in the energy mix at the expense of oil and solid fuels. This growth will take place above all in countries of southern Europe. In north-western Europe, with stagnant PEC, gas can expand its market share only by ousting rival fuels, as in Germany, for example. Here, notwithstanding the decline in PEC from about 2000 onwards, gas consumption keeps growing and gas will widen its share in the energy mix at the expense of competing fuels.

In western Europe as a whole, a positive development is emerging for the use of gas in power stations. According to various forecasts, existing gas consumption in power stations is likely to double from about 50 mtoe now to the order of 90 or even 140 mtoe in 2010. The main driving force behind this development is the power-generating industry in Italy, which has until now been characterised by a high share of oil - although we hear from Italy that the power generators are hesitant to share this optimistic view. Other countries with high growth rates are the UK and Spain. In Germany, especially western Germany, no significant increase in the use of gas in large power stations is expected in the next ten years due to the existing structure of power plants and the relative economic advantages connected with the operation of such power stations.

V. Conclusions

Natural gas is an energy source with a promising future. In the next 15 years, demand in western Europe will increase by more than 100 mtoe with half of the increase coming from the power sector. On the supply side, the growing supply options mean stiffer competition, even taking into account the additional sales potential. Despite the seemingly comfortable supply situation and a temporary supply overhang, Europe must not lose sight of the long-term needs of its import-dependent gas industries in continental Europe.



“Middle East Gas : Prospects & Challenges”

Session (5)

Natural Gas Demand in Europe / Prospects for Middle East Gas

Paper No. (5-4)

Prospects for Middle East Gas in Europe

Mourad Preure & Ahmed Messili

Sonatrach,

ALGERIA



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Prospects for Middle East Gas in Europe

Nikoly I. Belyi
Director, Gazprom
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“Middle East Gas : Prospects & Challenges”

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Natural Gas Demand in Europe / Prospects for Middle East Gas

Paper No. (5-6)

Natural Gas Demand Prospects in Europe

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NATURAL GAS DEMAND PROSPECTS IN EUROPE

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ABSTRACT

The development of natural gas demand in Europe reflects all the technical, economical, environmental or political factors that make it one of the best energy options for the future.

Despite the high consumption values, European countries cover only around 45-46% of their demand either from own production or imports, even from the countries in the same geographical zone. The growing imbalance between domestic supplies and demand, in most countries and on the scale of Europe, as well as the increasing distance between potential resources and major consuming areas, will tend to launching numerous large capacity long distance pipeline projects.

Turkish energy demand is increasing rapidly in the direction of its economical growth. As the progress for the economic development in Turkey has confirmed that the total gas consumption in power generation will maintain the leading position of the natural gas industry in the future. Turkey has been evaluating serious projects for some time regarding the near future. In order to be able to cover our current supply-demand deficiency in a short period, BOTAS got in touch with our existing supply sources.

Beyond the other new and existing supply sources to meet the natural gas demand for Turkey, in the region surrounding the Caspian Sea, the newly independent states with their important oil and gas deposits have been the focus of all attention.

Turkey, being an energy bridge between east and west, has two mega projects in order to meet both Turkish and European markets natural gas demand:

1. Turkmenistan-Turkey-Europe Natural Gas Pipeline Project.
2. Iran-Turkey-Europe Natural Gas Pipeline Project.



“Middle East Gas : Prospects & Challenges”

Session (5)

Natural Gas Demand in Europe / Prospects for Middle East Gas

Paper No. (5-7)

Gas link between the Gulf and Western Europe : Projects, Challenges and Prospects

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OBSERVATOIRE MÉDITERRANÉEN
DE L'ÉNERGIE

**GAS LINK BETWEEN
THE GULF & WESTERN EUROPE
PROJECTS, CHALLENGES & PROSPECTS**

Dr Naji ABI-AAD
OME Senior Consultant

**Second Doha Conference on Natural Gas
17-19 March 1997**

GAS LINK BETWEEN THE GULF & WESTERN EUROPE

Projects, Challenges & Prospects

Abstract

The abundant natural gas reserves in the Gulf would meet the growing gas demand in Western Europe where a slightly increasing production which would decline over time means that growing gas imports need to be secured. A gas transportation link between the two regions, in form of economically viable chains of liquefied natural gas (LNG) or gas pipelines, needs to be found. Almost all gas pipeline schemes between the Gulf and Western Europe will inevitably pass through East Mediterranean that will act as an important transit zone, with the growth in the region's own gas demand and import need helping to forge such an intermediary link. Nevertheless, many economic constraints and political challenges need and have to be overcome, especially when knowing that a gas link between the Gulf, East Mediterranean and Europe, particularly in form of pipeline, will ultimately lead to more economic integration and interdependence as well as to more political co-operation and collaboration between the different parties including the transit states, and would help in the further development of the Gulf and East Mediterranean. All that will assist in building a peaceful political and economic environment embracing those two regions and Europe.

I- Natural Gas Demand & Import in Western Europe

While several alternative gas demand forecasts have been proposed for Western Europe, they all seem to converge on the conclusions that natural gas consumption in the region will outstrip the growth in use of other energy sources, that significant additional gas supplies for the European market will need to be found beyond the year 2000, and that the gap between domestic demand and indigenous production may become severe by 2010.

Indeed, long term outlooks for natural gas demand in Western Europe show an increase from 333 billion cu m/year (bcm/y) in 1995 to between 360 and 400 bcm/y by the start of the new century, and an expected average of 485 bcm/y in the year 2010. Around that time, the share of natural gas could reach more than 30 per cent of the European total primary energy consumption.

The main driving forces behind the expected increase in gas demand in Western Europe include the growing concern about a possible enhanced green house effect; the technical developments in gas-fuelled power generation having resulted in higher efficiencies; the high level of convenience to consumers that represents natural gas in its networked form; and the diversification of energy sources.

Meanwhile, natural gas output in Western Europe is expected to just show a slight increase from 240 bcm/y in 1995 to an average of 250 bcm/y at the beginning of the new century, and 265 bcm/y by the year 2010. Only Norway would be able to increase its gas production level during the next decade, whereas virtually all other West European producers would see their output level stagnate or even fall.

The fast growing demand for natural gas combined with an indigenous production which would moderately advance and would eventually decline over time, means that increasing volumes of gas need to be imported. West European import of natural gas is expected to steeply grow from 93 bcm/y in 1995 to an average of 130 bcm/y in the year 2000 and 220 bcm/y by 2010.

**Natural Gas Demand, Production & Import
in Western Europe**
(billion cu m/year)

	1995 (actual)	<i>forecasts</i>	2000	2010
Demand	333	<i>minimum</i>	360	450
		<i>average</i>	380	485
		<i>maximum</i>	400	520
Production	240	<i>minimum</i>	240	240
		<i>average</i>	250	265
		<i>maximum</i>	260	280
Import	93	<i>minimum</i>	120	210
		<i>average</i>	130	220
		<i>maximum</i>	140	240

The main existing external gas suppliers to Western Europe, namely Russia and Algeria, are expected to meet most of the incremental demand, and to remain the main pillars of natural gas supply to the region. However, due to the expected inability of those two gas exporters to meet the whole growing demand, and to the need for diversification of supply, there will be a call for other sources of natural gas. Those would include the Gulf that may well be in a good position to contribute to the West European gas requirements in the years to come, and thus to diversify its markets.

II- Natural Gas in the Gulf

The Gulf countries—namely Bahrain, Iran, Iraq, Kuwait, Oman, Qatar, Saudi Arabia, the United Arab Emirates (UAE) and Yemen—include large actual and potential natural gas producers that can significantly alter the supply picture, both within the region and internationally. A helping factor is the quite huge gas proven reserves and resources in the area in relation to its current and foreseeable level of demand.

As of early 1996, total natural gas reserves in the Gulf were estimated at 44,970 billion cubic meters (bcm), accounting for about 30 per cent of the world total. The Gulf gas reserves are unevenly distributed among the region's countries, ranging from 20,963 bcm in Iran, 7,070 bcm in Qatar, 5,831 bcm in the UAE, 5,341 bcm in Saudi Arabia, 3,360 bcm in Iraq, and 1,494 bcm in Kuwait, to only 481 bcm in Yemen, 283 bcm in Oman and 147 bcm in Bahrain.

Considering the large potential of the Gulf, little has been done so far to exploit its gas reserves. The 1995 gas reserves-to-production ratio in the region, a measure often used as an indication of near-term supply capability, was covering around 240 years compared to a world-wide average ratio of 62 years only.

Moreover, the Gulf still has a very marginal share in the international gas trade, estimated at a negligible 1.8 per cent in 1995, limited to flows of LNG export from Abu Dhabi to Japan and minor supplies from Oman to Ras Al-Khaimah (not including some "national trade" flows from Sharjah to the other northern UAE emirates).

Nevertheless, in the near future, the Gulf would come to play a significant role on the world gas market with the accomplishment of many important LNG projects in Oman, Yemen, and particularly in Qatar. Meanwhile, many proposed gas pipeline schemes aimed to serve regional and interregional markets would be implemented. Some of these gas pipeline projects have been oriented towards Western Europe.

III- LNG Projects in the Gulf

The first LNG liquefaction plant in the Gulf was built on Das Island in 1977 by **Abu Dhabi Gas Liquefaction Co. (ADGAS)**. The plant actually consists of two liquefaction trains designed to annually produce up to 6 million tons of LNG, planned to be expanded to around 8 million tons/year by 1998. Almost all output has been exported to the Japanese Tokyo Electric Power Co. (Tepco) under long-term contracts. Since late 1994, ADGAS has sold individual LNG cargoes on the spot market to European customers.

It took around 20 years for the second LNG liquefaction plant in the Gulf, **Qatargas**, to come on stream in early 1997. The Qatargas plant comprises two 2-million ton/year LNG trains, whose layout and design will enable total capacity to be extended by 2 million tons/year in 1999. The whole output of Qatargas is to be channelled to Japan's Chubu Electric Co. and to a consortium of seven other Japanese gas and power utilities.

Another Qatari project, **Ras Laffan LNG (Rasgas)**, is expected to start producing in mid-1999 with an initial annual capacity of 5 million tons, to be expanded to 10 million tons in a second phase. A good portion of Rasgas output will be exported to the South Korean company Korea Gas, with the remaining part probably going to Thailand's Petroleum Authority (PTT), China Petroleum Corp. of Taiwan, Turkey's Botas, Wing Group of China, and India's Essar Group.

A third Qatari LNG scheme that still needs to be finalised consists of a project headed by the US **Enron** Corp. which has proposed a liquefaction plant with a capacity of 5 million tons/year.

In Oman, a final decision was taken in 1994 to go ahead with the **Oman LNG** project to annually produce 6.6 million tons from a liquefaction plant scheduled to enter production at the beginning of the year 2000. A large part of the project's output will be channelled to Korea Gas, with the remaining portion may be going to PTT, Botas, and Italy's ENEL.

In Yemen, a green light was given in 1995 to the 5.3-million ton/year **Yemen LNG** project. Part of the LNG could be imported as from the year 2000 by Turkey (Botas) as well as Asian and Far Eastern gas and power utilities.

Iran has also expressed its interest to implement an 15- to 20-million ton/year LNG scheme as a way to serve West European and Asian gas markets. Many European and Japanese trading authorities have welcomed the proposal but the project has still to be detailed.

It is noteworthy that most of the LNG projects in the Gulf are aiming to serve Far Eastern markets and not European ones. That is both because the price for gas delivered into the West European grid, currently indexed on oil products, is presently too low to pay for the cost of liquefaction, transport and regasification of Gulf LNG, and because the Far Eastern markets are ready to pay a considerably higher price, meaning that it is almost invariably more convenient to ship LNG to the Far East than to Western Europe. As long as those two conditions of gas prices are not changed, it is unlikely that significant LNG volumes will travel westward, with the exception of occasional spot shipments.

A recent attempt to shape a Gulf LNG project oriented towards European markets already ended into failure. In 1994, the different partners of a joint venture, Eurogas LNG, between Qatar General Petroleum Corp. (QGPC), Italy's Snam, and the US businessman Nelson Hunt aiming to annually produce up to 9.2 million tons of LNG to be sold on Italian and other West European markets, were unable to agree on the prices for gas. The foreign partners shares were subsequently transferred back to QGPC that has kept the venture as a legal entity, while shelving the project itself.

Nevertheless, there are many factors that can help to brighten this grey picture, and a number of interesting technology trends which may improve future prospects of the LNG option to transport Gulf gas to Western Europe. A steady downward trend in capital costs of LNG projects has already been achieved through the use of better technology in liquefaction plants, the reduction of shipping costs, and the utilisation of technical innovations in regasification terminals.

In another development, the Suez Canal Authority, managing the traffic in one of the most important waterways between the Gulf and Europe, recently decided to give discounts of up to 35 per cent of transit fees to LNG carriers that will be going from Qatar (and any other Gulf potential gas exporter) to Europe, in a bid to win lucrative Gulf petroleum export trade and thwart plans for rival pipelines.

All these positive trends, in addition to difficulties that would face the implementation of gas pipeline projects between the Gulf and Western

Europe, could make the LNG option to transport Gulf gas to the old continent attractive ever again.

IV- Gulf-Western Europe Gas Pipeline Projects

Projects have been advanced to pump Gulf natural gas all the way to Western Europe, or to bring gas by pipeline from the region to Mediterranean coasts for liquefaction and further shipment to European terminals. Those pipelines would mainly originate from the large gas reserves countries in the area, namely Iran and Qatar.

Iran has been holding talks with several countries and companies on exporting its natural gas to Western Europe through pipeline. A preliminary agreement to study the feasibility of exporting Iranian gas to France and then to Italy and Germany was signed in 1990 between Gaz de France (GdF) and the National Iranian Gas Company (NIGC). The study considered several options including transporting gas through a 32-bcm/y pipeline (via Russia or Turkey), or through a combination of pipeline and LNG (gas pipeline to a liquefaction plant either at Iskenderun in southern Turkey, or at Port Said in Egypt). The co-operation with GdF was extended in early 1993 when a joint-venture, called the Iranian-French Gas Co-operation Company Ltd, was set up to study and promote gas export projects.

Likewise, Qatar has been considering the construction of a gas pipeline to Western Europe since March 1985 when Doha signed an agreement with Ankara for carrying out a joint feasibility study on a 4,900-km, 30-bcm/y scheme through Saudi Arabia, Iraq, Syria and Turkey.

Another gas pipeline project that partly aimed to serve the West European markets is the Middle East Gas Loop scheme which has been jointly promoted since late 1992 by Chiyoda Corp. of Japan, the UN

Industrial Development Organisation (UNIDO), and ENI of Italy. The original plan foresaw a 6,900-km, 24/36/48-inch gas loop of four 28-bcmy segments circling Iraq and Kuwait, and passing through Iran, Turkey, Syria, Jordan, Saudi Arabia, the UAE and Oman. The loop route design would provide access to multiple sources of natural gas existing all over the region and assure in that way some security and stability of long-term gas supplies to consumers. Three spur gas pipelines to planned LNG terminals on the coasts of Iran, Oman and Syria would assure LNG supplies to Asia and Europe.

Gas pipelines from the Gulf could reach Western Europe with volumes much larger than those of LNG projects, and could also provide natural gas to a number of transit countries including the growing market of East Mediterranean, thus contributing to the economic viability of such schemes. Gulf-Western Europe gas pipelines could eventually be built “by segments”, the first one to the East Mediterranean region, ensuring a good return on investment, before implementing the others.

V- Natural Gas Demand & Import in East Mediterranean

Indigenous natural gas production in East Mediterranean is concentrated in only one country, Syria, with minor output in Jordan. Syrian gas production is expected to increase from 4 bcmy in 1995 to between 7 and 9 bcmy at the beginning of the new century, and between 11 and 16 bcmy in the year 2010. These volumes are planned to be domestically used, meeting a growing share of Syria’s energy needs.

Syria’s as well as Turkey’s utilisation of natural gas is well established and rapidly increasing, but the pace of growth in their gas demand, and the creation of a gas industry in the other East Mediterranean countries depends on the effective availability of natural gas. The figures proposed in the following table thus represent a scenario of the possible evolution of gas utilisation in the region if sufficient supplies will be made available. The table shows an increase in total gas demand in the area from 12 bcmy in 1995 to between 24 and 37 bcmy by the start of the new century, and between 47 and 73 bcmy in the year 2010.

**Natural Gas Demand, Production & Import
in East Mediterranean**
(billion cu m/year)

Year/ Country	1995 (actual)			2000 (forecasts)			2010 (forecasts)		
	Demand	Production	Import	Demand	Production	Import	Demand	Production	Import
Israel	0	0	0	3-5	0	3-5	5-11	0	5-11
Jordan	0	0	0	1-2	0-1	1	3-8	0-3	3-5
Lebanon	0	0	0	1	0	1	3	0	3
Syria	4	4	0	7-9	7-9	0	11-16	11-16	0
Turkey	8	0	8	12-20	0	12-20	25-35	0	25-35
Total	12	4	8	24-37	7-10	17-27	47-73	11-19	36-54

In the mean time, East Mediterranean gas production is expected to grow from 4 bcmy in 1995 to between 7 and 10 bcmy by the year 2000, and between 11 and 19 bcmy in 2010. With an increasing indigenous production that could not fully meet the steep growth in demand, the region would be a net gas importer, and a possible shortage of indigenous output would only increase the volumes that would need to be brought in from the Gulf and other areas. By the beginning of the new century, the East Mediterranean region would need to import between 17 and 27 bcmy, compared to only 8 bcmy in 1995. By the year 2010, gas imports are expected to reach between 36 and 54 bcmy.

Turkey, with its large population and industrial base, and its determination to expand the use of natural gas for satisfying its rapidly growing energy needs, is constituting the main gas consumer and importer in East Mediterranean. It currently imports gas from Russia and Algeria; in the future it is likely to import gas also from Central Asia (particularly Turkmenistan), Iran, Iraq and Egypt. Turkey is also expected to play the role of a hub, receiving and dispatching gas to and from the surrounding regions, and to become more and more a cross-roads for future natural gas trade between Central Asian and Gulf producing countries and Western Europe.

VI- Gas Export Projects from the Gulf to East Mediterranean

In addition to gas pipeline schemes from Iran and Iraq to Turkey that was also proposed Egyptian gas through the Levante Gas Pipeline project and in LNG form, a gas network linking the Gulf with East Mediterranean countries was suggested by Qatar and Abu Dhabi,

Iran would start pumping natural gas to Turkey through a 42-inch gas pipeline for a 22-year period starting in 1999 under the terms of an agreement concluded in August 1996. Iran would build the 270-km section of the line running from Tabriz to the border. For its part, Turkey would build the section of the line from the border to Erzerum, which at a later stage may be extended to Ankara. That gas link from Iran would be used to channel up to 8 bcmy from Turkmenistan to Turkey by the year 2000, and would eventually help to pump Iranian and Turkmen gas to Europe.

Plans existed before the 1990-91 Gulf crisis for an Iraqi gas pipeline from Kirkuk into Turkey, with a proposed terminal at Batman. But with all the southern and northern fields linked to the gas trunkline running along Iraqi spine, the scale of thinking had been clearly way beyond the supply of gas only to a Turkish terminal. Indeed, the Iraqis were planning of linking their gas pipeline export system with the line running down from the former Soviet Union through Romania and Bulgaria to Ankara. That presupposed contradeals whereby Iraqi gas replaces Soviet's. Given the economics of scale that would have to come into play when natural gas is piped over such distances, an annual capacity approaching 30 bcm must have been considered.

More lately, in August 1996 a preliminary agreement was reached between Baghdad and Ankara on the construction of a 1,380-km, 10-bcmy gas pipeline between six gas fields in northeastern Iraq and the heart of the Turkish Anatolian region.

Egypt recently entered the arena with the Levante Gas Pipeline project that was proposed in October 1995 by ENI for exporting Egyptian gas to East Mediterranean countries. The ultimate capacity of the gas pipeline

would be between 13 and 16 bcmy in 2010, while an initial potential of 7 to 8 bcmy would be available by the year 2003. Three different route options have been considered for the project: either an onshore cross-country pipeline connecting Egypt to Israel, Jordan, the Palestinian Territories, Lebanon, Syria and Turkey; or an onshore pipeline from Egypt to Haifa in Israel, serving Israel, Jordan, and the Palestinian Territories followed by an offshore line from Haifa to Turkey; or an offshore pipeline directly connecting Egypt to Turkey. For those alternatives it was assumed that the point of departure for the Levante Gas Pipeline would be at Port Said, while the terminal would be at Iskenderun.

One year later, in November 1996, a memorandum of understanding was concluded between Egypt, the US Amoco and Botas for setting up a gas liquefaction plant on the Egyptian Mediterranean coast for exporting around 7 million tons/year of Egyptian LNG to Turkey.

It is important to mention within this context that the actual natural gas export potential of Egypt remains limited especially if no more gas reserves are discovered over and above those increasingly required to meet the country's domestic energy needs and those already dedicated for export.

Aware of the importance of East Mediterranean, Abu Dhabi National Oil Co. (ADNOC) and QGPC proposed in the late 1980s a gas pipeline network that would enable Abu Dhabi and Qatar to supply countries in the region as well as some others in the Gulf with natural gas. The 1,680-km main gas network would have an annual capacity of about 21 bcm, of which 60 per cent would be supplied by Qatar, and the remaining 40 per cent by Abu Dhabi, running from those two states to Manama, Kuwait City and Baghdad. An expanded gas network would boost the capacity to a total of around 26 bcmy and the length to 3,000 km, and would extend to the Syrian-Jordanian border, and from there to Amman and Damascus. Since the conflict over Kuwait in 1990-91, however, the Gulf-East Mediterranean gas network project has been put on ice. Nevertheless, five years later, in Spring 1996, Iraq offered Qatar the use of its pipeline network to export natural gas to Turkey and other East Mediterranean countries.

A possibility has been mentioned to build a 1,800-km gas pipeline that would carry Qatari gas to Israel through Saudi Arabia and Jordan. Although most of the pumped gas would be liquefied at Ashkelon for export to European markets, some gas volumes would be expected to meet domestic needs in Israel and its neighbouring countries.

VII- Challenges & Prospects

For gas export projects from the Gulf to Western Europe to see the light, many economic and political constraints have to be put away. Of the challenges to be overcome are those concerned with the huge financing of the required new gas production capacities and transport infrastructure, that necessitates new and innovative financing approaches under which both gas producing and consuming countries share the financial burden resulted from such capital-intensive projects.

In fact, although a significant reduction in the costs of long distance onshore and offshore transportation of gas by pipeline has been achieved through the use of more efficient technologies, and a steady downward trend in capital costs of LNG projects has already been accomplished, an investment of between US\$10 and 15 billion is still required to build a 5,000-km, 25- to 30-bcm/y gas pipeline, while a long distance LNG chain with an annual capacity of between 7 and 9 million tons necessitates about US\$6 to 8 billion of capital cost. Those figures do not even include the technical transport costs.

Moreover, gas export projects are likely to face a rarefaction of available capital, due both to the competition of many other infrastructure schemes for funds, in the Gulf itself and the Middle East as a whole, in Eastern Europe and in Asia, and to the reduction of financial possibilities of the traditional lender countries and the oil exporting states in the region.

As prerequisite for getting the required funds from banks and other financing bodies, long-term supply contracts between the West European and East Mediterranean gas companies and the Gulf gas producers need to be concluded. For these contracts where the base-price is currently indexed to those of oil and petroleum products, a sound market-based gas

pricing policy should be found, under which prices are to ensure the economic viability of gas export projects.

Nevertheless, economic issues are not the only determining factors for the realisation of gas export projects which are also risk investments. That is especially true for the Gulf-Western Europe gas pipelines involving the crossing of a large number of territories, which, in order to materialise, need good relations and co-operation among the upstream, downstream and transit countries, in addition to political stability all along their routes. If a final peace in the Middle East between the Arabs and Israel is reached (Inshallah!), it will surely shift in the perception of political risk of the area and its Gulf sub-region, and would, it is hoped, help more concentrated efforts to gather and tackle the other factors of internal instability and interstate conflict in the region, in addition to the issues of embargo on Iraq and sanctions against Iran.

We believe that gas export projects, especially pipelines, would help to mollify tensions by resulting in more economic integration and interdependence as well as more political co-operation and collaboration between the different parties including the transit states, and would help in the further development of the Gulf region and the Middle East as a whole. All that would assist in building a peaceful political environment on the southeastern flank of Western Europe and in consolidating a reliable and stable climate for economic and energy investment and trade between the Gulf, East Mediterranean and Europe.

* * * * *

**SECOND DOHA CONFERENCE
ON NATURAL GAS**
March 17 - 19 , 1997
DOHA - QATAR



مؤتمر الدوحة الثاني للغاز الطبيعي
١٧ - ١٩ مارس ١٩٩٧
الدوحة - قطر

“Middle East Gas : Prospects & Challenges”

Session (6)

Natural Gas & Power Generation

CHAIRMAN

Dr. Ibrahim Ibrahim

Economic Advisor, Emiri Diwan

STATE OF QATAR

**SECOND DOHA CONFERENCE
ON NATURAL GAS**
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“Middle East Gas : Prospects & Challenges”

Session (6)

Natural Gas & Power Generation

Paper No. (6-1)

Demand Prospects for Gas in Emerging Economies

R. F. Guerrant

President, Mobil Power Inc.

U.S.A.



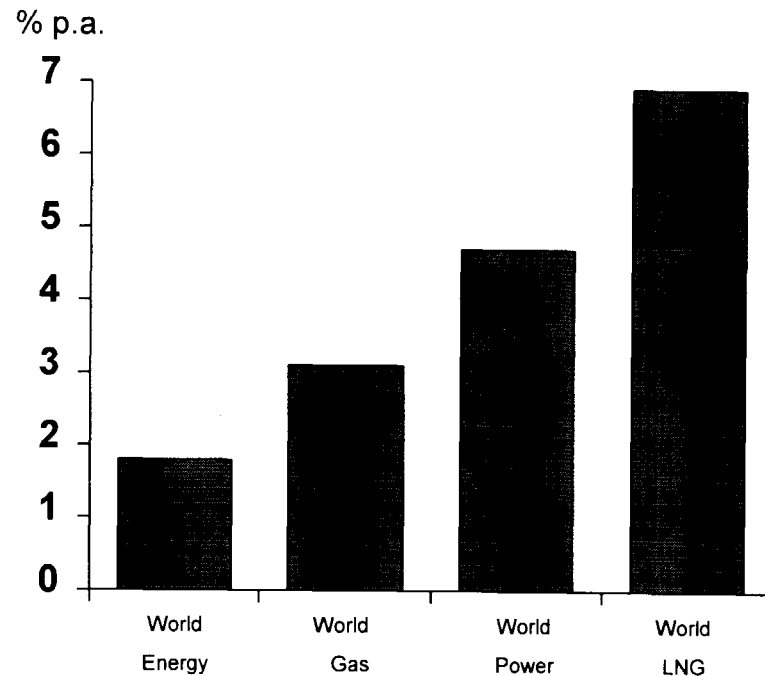
“Demand Prospects For Gas In Emerging Economics”

Second Doha Conference on Natural Gas

**Richard F. Guerrant, President, Mobil Power Inc.
Doha, Qatar
March 17-19, 1997**

Worldwide Energy Growth is being led by LNG/Gas and Power

Energy Demand Growth Rates



Key Drivers

- Rapid economic growth, particularly in Asia.
- Improvements in end-use technology favor gas-fired power.
- Inadequate domestic gas supplies: LNG required.
- Tightening environmental legislation.

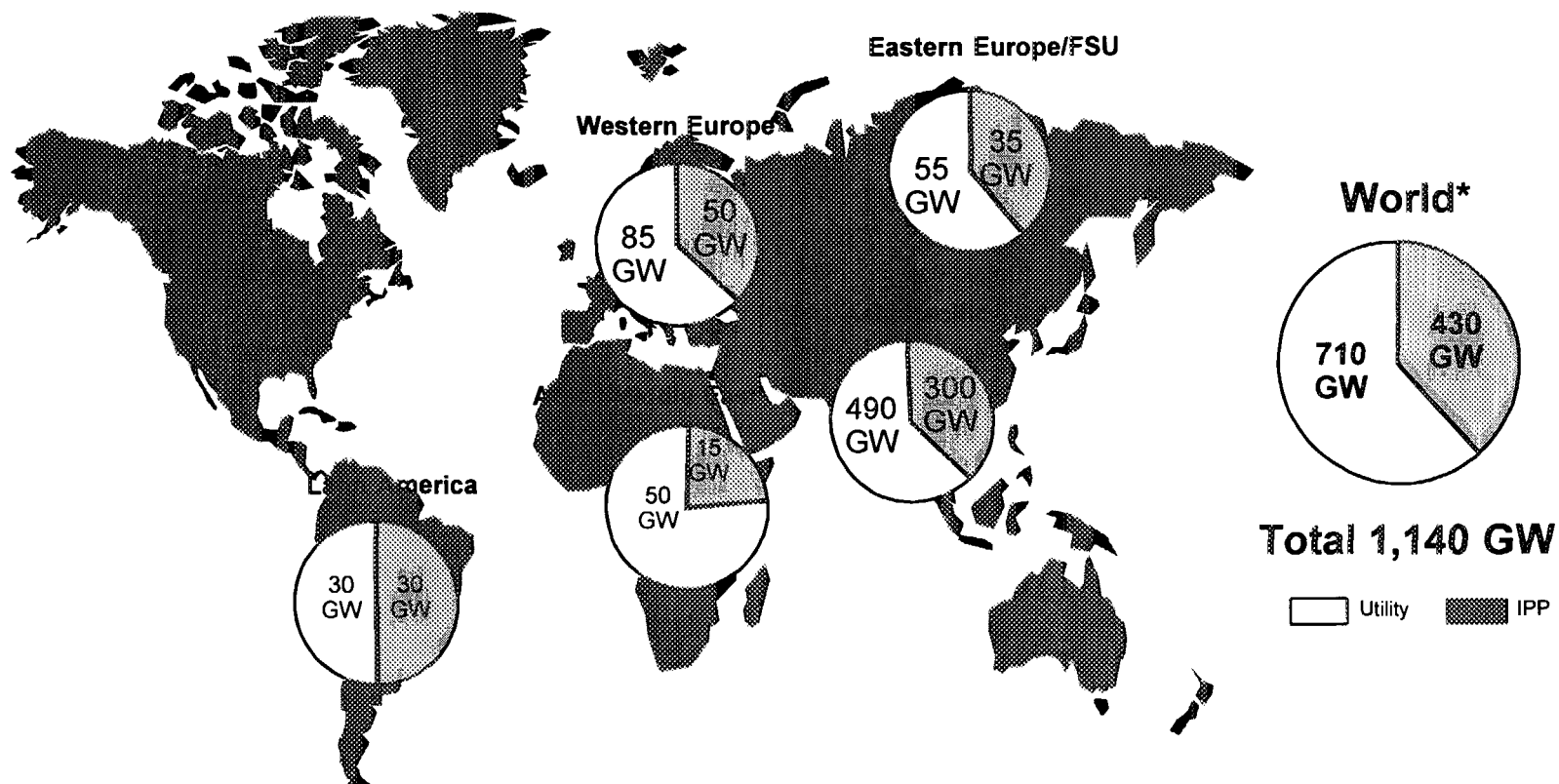
Gas Demand Implications

- Overall, gas demand will increase by nearly 3% p.a.
- Largest growth will come in Asia, at 5% p.a.
- Gas market share will grow from 23% to 28%.
- LNG market share doubles, from 1% to 2% of total energy.

Global Power Demand Is Projected to Double Over The Next 15 Years with 1140 GW's of New Capacity (excluding North America) to be Added by 2010

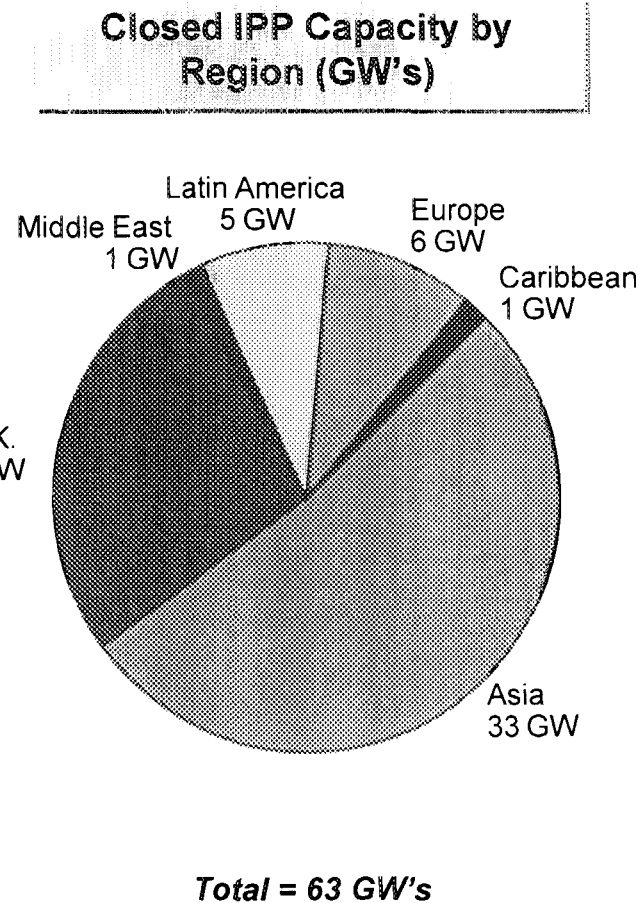
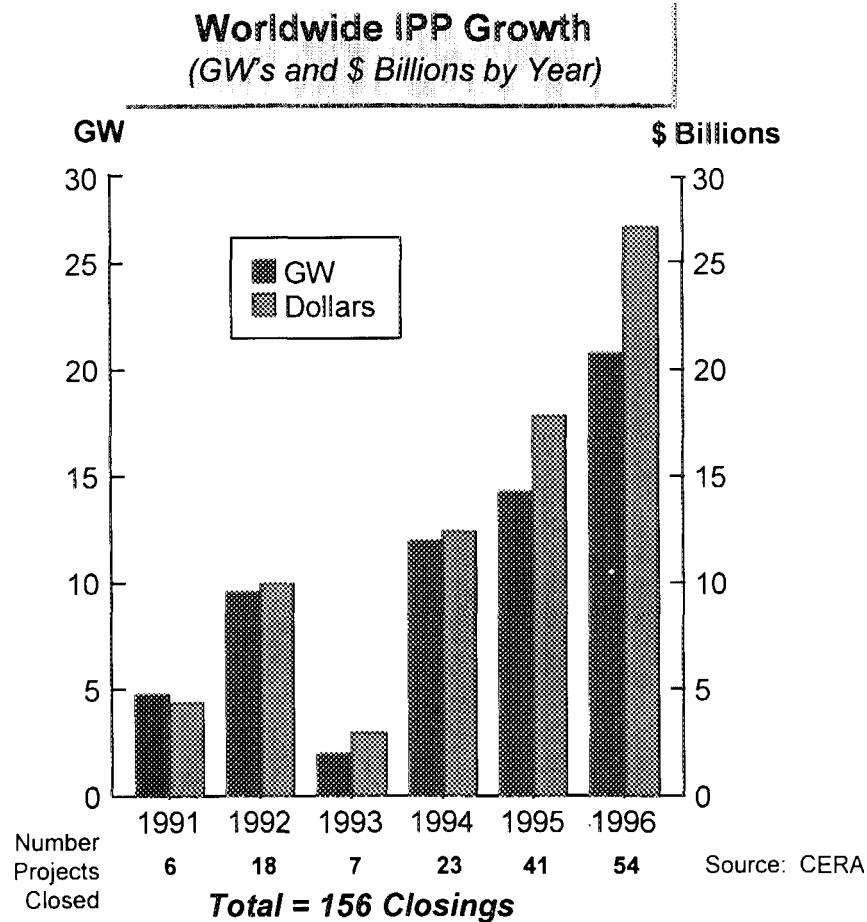
We expect Independent Power Projects to capture over 400 GW's or 40% of new capacity requirements over the next 15 years.

**Worldwide* Projected Capacity Additions
by Region (1995 - 2010)**



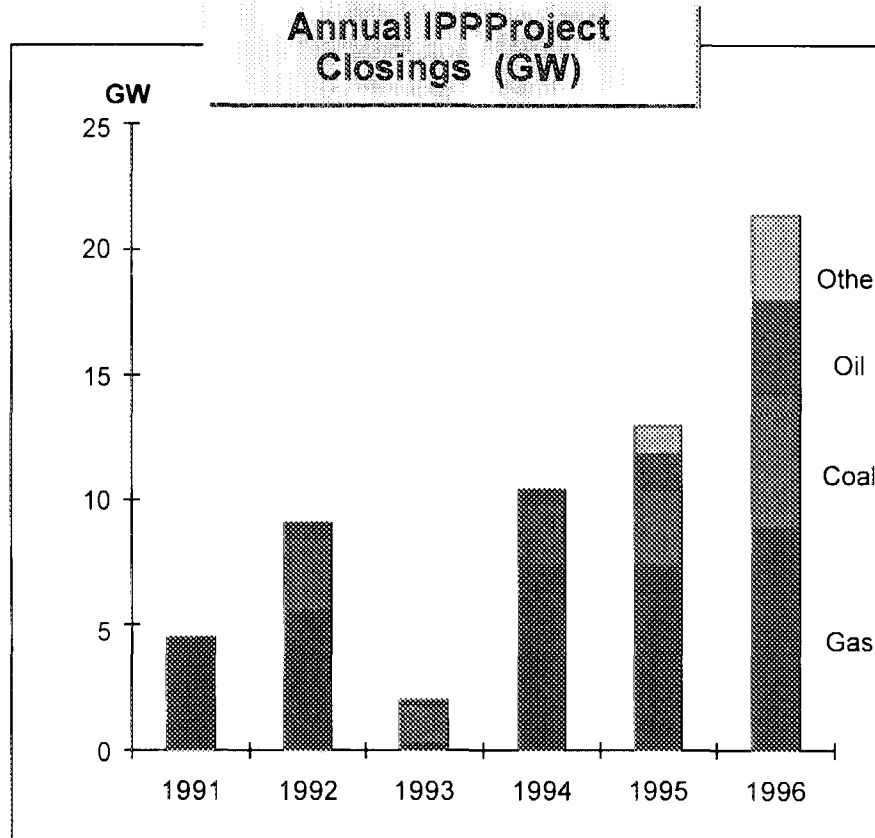
* Note: Excludes North America
Source: CERA

Investment in IPP projects over the last five years has grown at an average annual rate of 15-20%, growing \$9 billion in 1996.

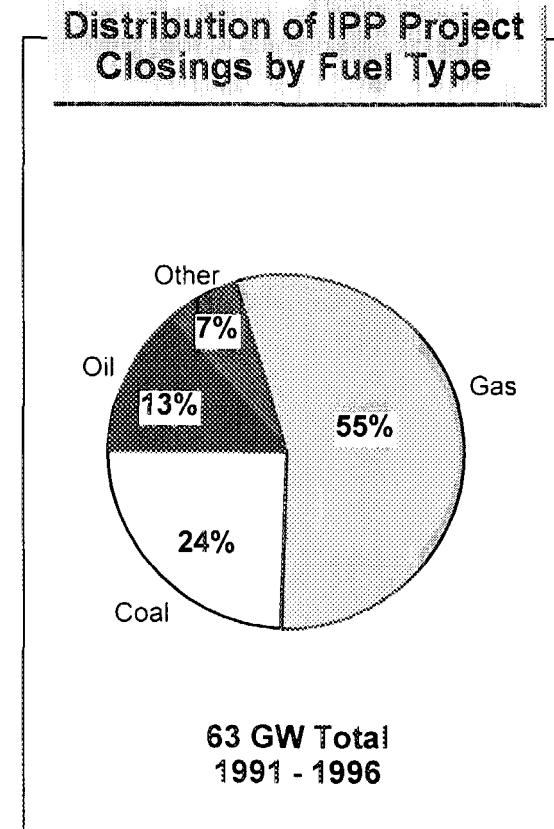


Over half of the projects to reach financial closure have been in Asia.

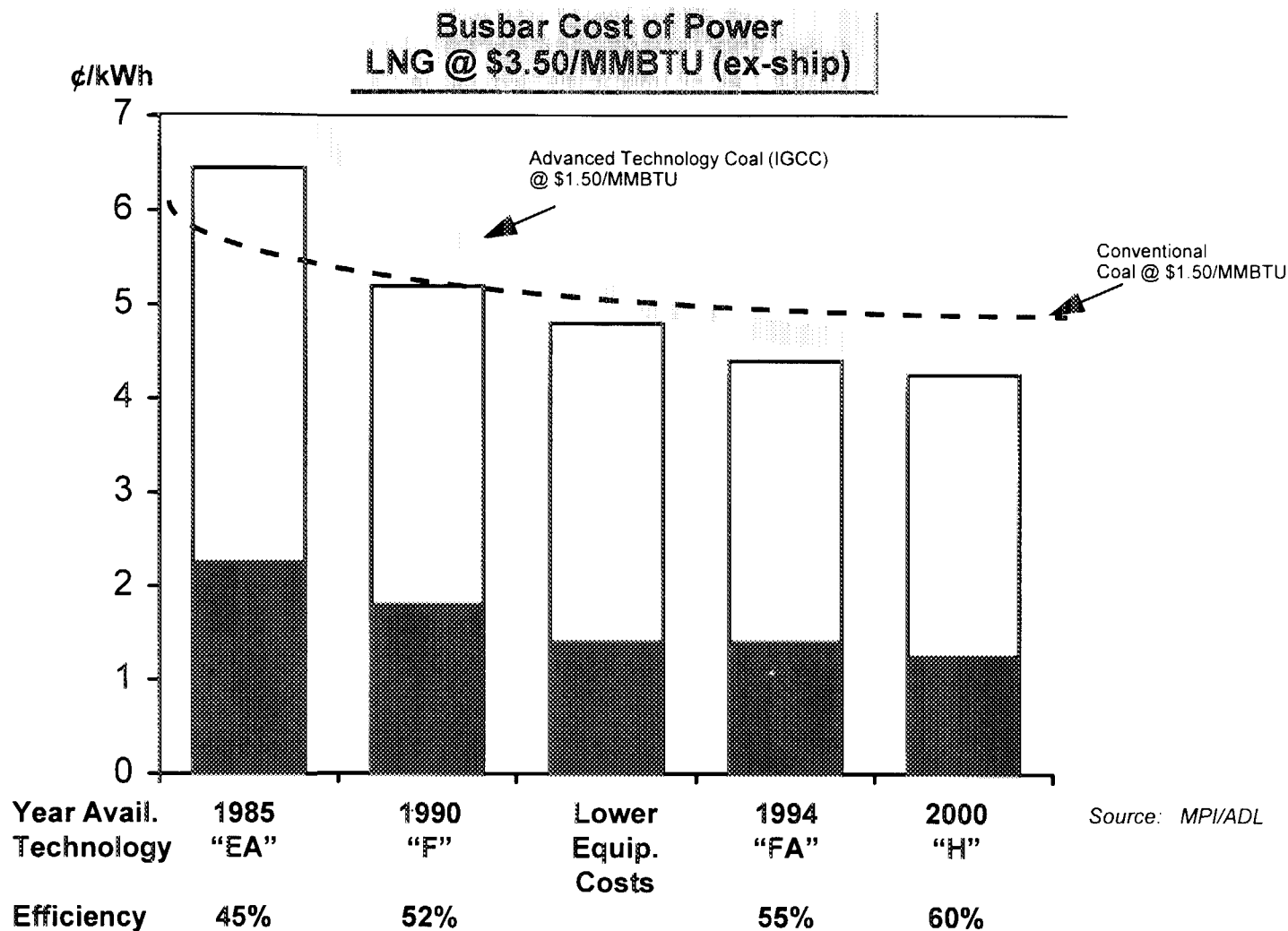
Because Of The Economic And Environmental Benefits, Over Half Of The IPP Project Closings Have Been Gas.



Source: CERA



Declining Equipment Costs And More Efficient Turbines Have Positioned LNG To Be Very Competitive With Imported Coal.

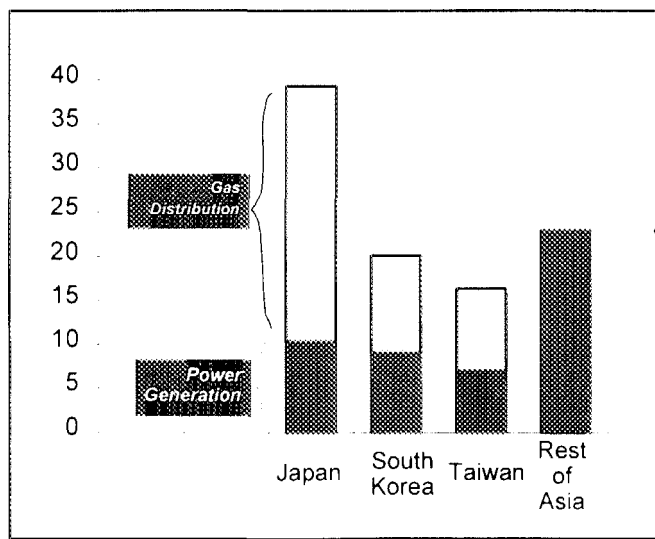


We believe that with a proactive approach, LNG can capture a significant portion of the future gas-fired IPP market, building on the benefits of gas.

LNG Will Be Required to Meet a Significant Portion of Future Gas-Fired IPP Demand Which Cannot Be Supplied By Local/Pipeline Gas.

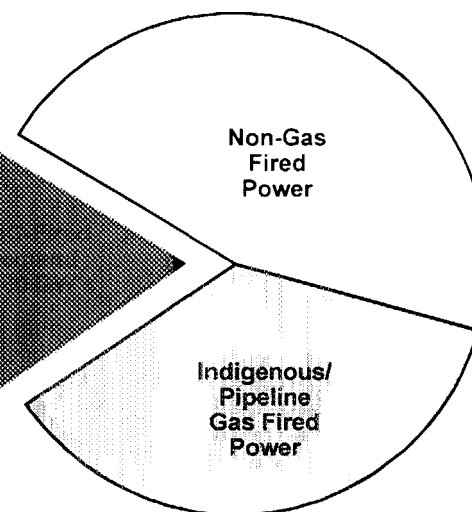
Incremental LNG Growth by Country (1996 - 2010)

MMTA



**Total IPP Market (1996-2010)
430 GW**

Potential LNG-Fired IPP Demand Will Require Over 50 MMTA of New LNG Supply

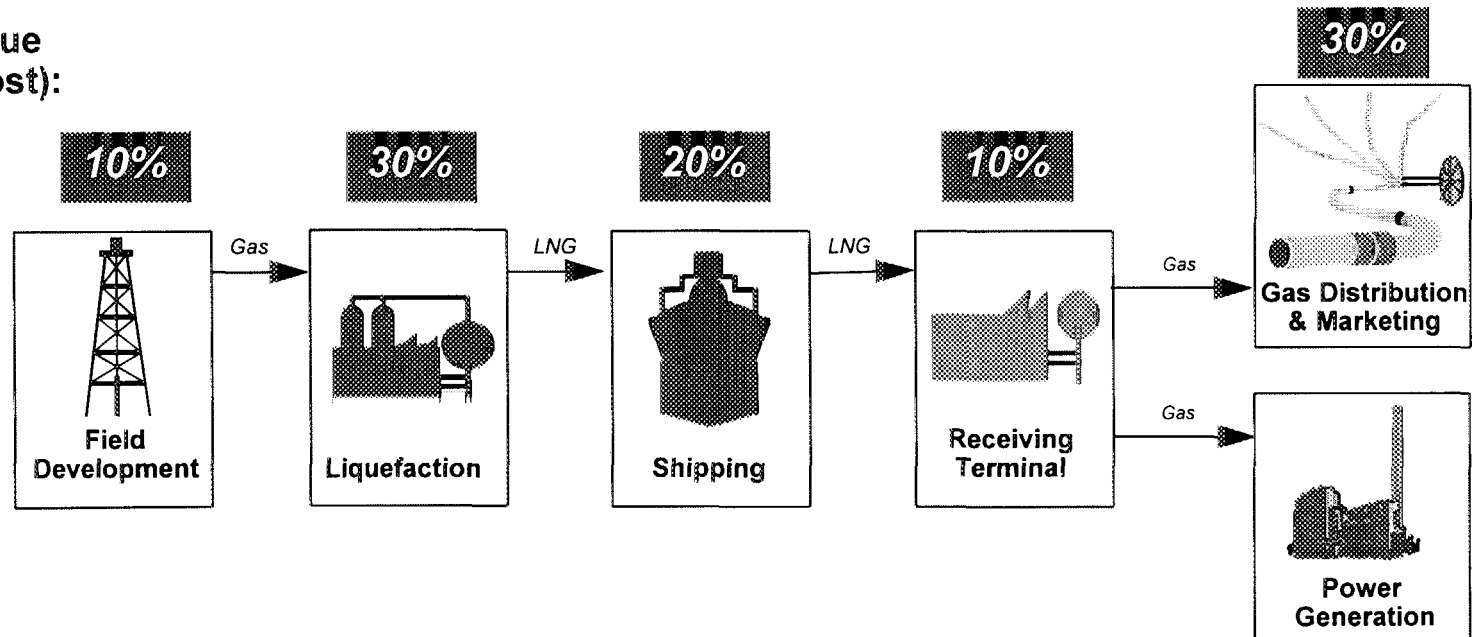


Note: 1 GW \approx 1 MMTA

Source: CERA

From Field Development To Power Generation in Emerging Economies, LNG-Fired Power Projects Require Development of The Entire Value Chain

(% of Value Chain Cost):



Total investments required will be in the \$5-10 billion range.

The Large Capital Requirements of LNG-Fired IPP Projects Make Financing Challenging

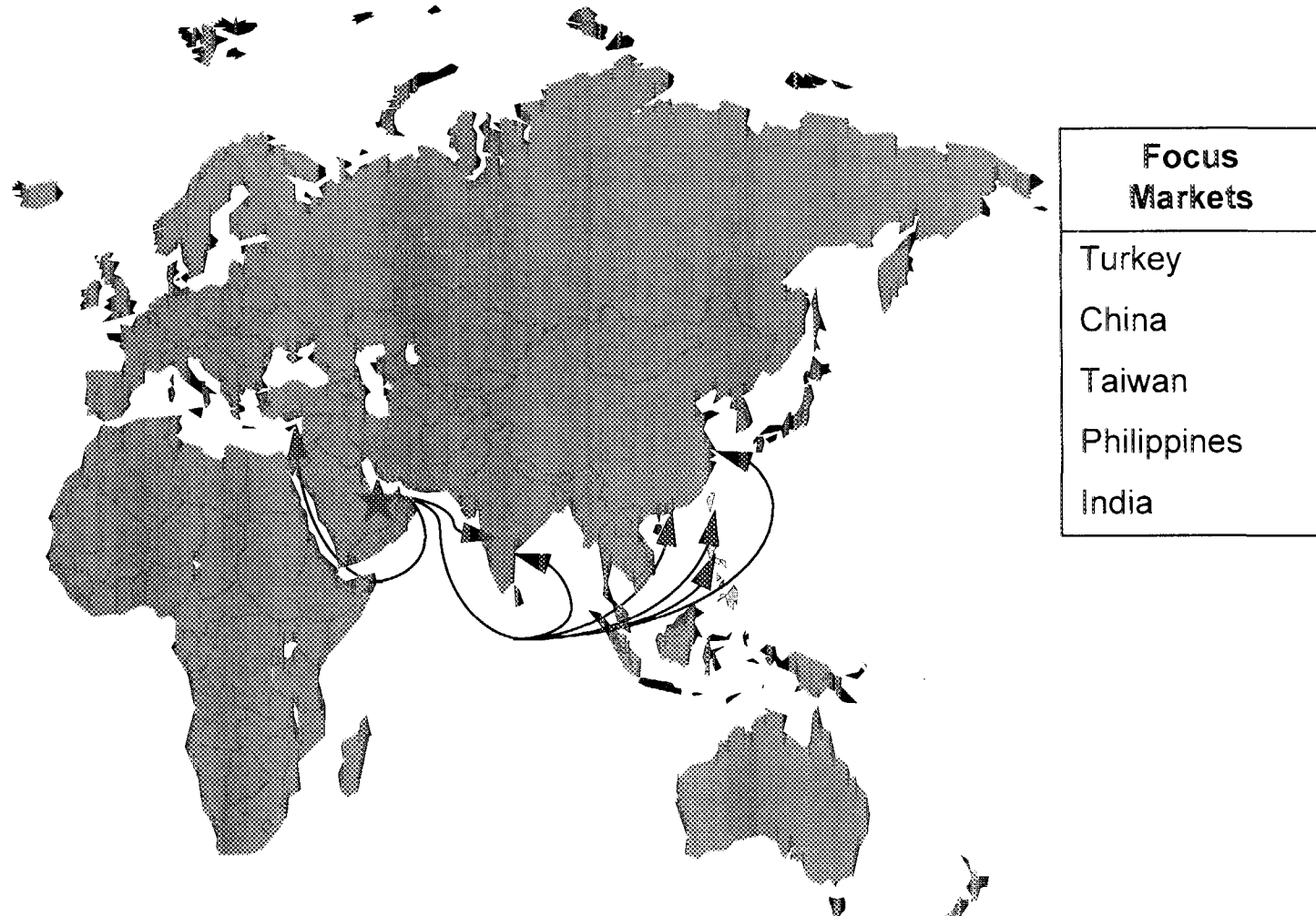
Country	Rating*	
Japan	(Aaa/AAA)	Investment Grade
Taiwan	(Aa3/AA+)	
S. Korea	(A1/AA-)	
China	(A3/BB)	
<hr/>		
India	(Baa3/BB+)	Non-Investment Grade
Philippines	(Ba2/BB)	
Thailand	(A2/A)	
Turkey	(Ba3/B)	

* Moodys/S&P

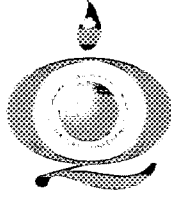
Key Implications

- Strong financing structure
- Solid contractual framework
- Manage completion risk
- Creditworthy participants
- Solid partnerships

Mobil Power Inc. Has 14 LNG-Fired IPP's Under Active Development In The Most Prospective Emerging Markets



These projects represent over 25 MMTA of potential LNG demand and we believe Qatar is positioned to capture this demand and become one of the world's largest LNG exporters.



“Middle East Gas : Prospects & Challenges”

Session (6)

Natural Gas & Power Generation

Paper No. (6-2)

LNG for Power Plants / The BOT Route

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Managing Director, Enron Development Corp.
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LNG FOR POWER PLANTS

THE BOT ROUTE

To date, the markets for LNG as a fuel for power generation have been confined mainly to the major electric power utilities in the Far East. Growth in these markets over the past 20 years has been dramatic as electric utilities switched from alternative fuels to natural gas.

The development in recent years of highly efficient and relatively low capital cost combined-cycle gas turbine power plant designs has opened a new and potentially very large market for LNG to fuel power plants in countries with developing economies. Potential LNG demand growth rates in these countries could be very large because of the critical need for additional power infrastructure.

Typically, developing countries are choosing to develop new power infrastructure with the aid of foreign investors via specific "build, operate and transfer" (BOT) projects, rather than via large government-owned utilities. These individual projects are relatively small when compared to the large facilities in place in Japan, Korea and Taiwan. In most cases, each individual power plant is project financed and owned by a specific single project joint venture company.

Although the market for gas to fuel these new power plants is potentially huge, the unique nature of the BOT structure creates a new set of unique challenges to the gas supplier. Such challenges include relatively low threshold volumes, unique flexibility requirements and higher credit/financial risks.

The author's presentation will compare the nature of these new BOT markets with the traditional Far East markets and outline the specific challenges which must be overcome before the BOT markets can be developed.



“Middle East Gas : Prospects & Challenges”

Session (6)

Natural Gas & Power Generation

Paper No. (6-3)

LNG Plant Combined with Power Plant

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LNG Plant Combined with Power Plant

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Abstract

The LNG plant consumes a lot of power for the natural gas cooling and the liquefaction. In some LNG plant location, a rapid growth of electric power demand is expected due to the modernization of the area and/ or the country. The electric power demand will have a peak in day time and low consumption in night time, while the power demand of the LNG plant is almost constant due to its nature.

Combining the LNG plant with power plant will contribute an improvement of the thermal efficiency of the power plant by keeping higher average load of the power plant, which will lead to a reduction of electrical power generation cost. The sweet fuel gas to the power plant can be extracted from the LNG plant, which will be favorable from view point of clean air of the area.

This paper examined the combination of the plants located in middle east for ;

LNG plant: 6.9 million ton per annum, MTA

Power: 800 mega Watt, MW

The feed natural gas cost was taken as 0.5 \$/MMBtu to 1.0 \$/MMBtu. Simple cycle and combined cycle were studied for the power plant.

This paper confirmed that the combination will contribute the electrical power cost reduction of 0.3-0.4cents/kWh.

Introduction

The LNG plant consumes a lot of power for the natural gas cooling and the liquefaction from ambient temperature to -162 deg.C. In some LNG plant location, a rapid growth of electric power demand is expected due to the modernization of the area and/ or the country. The electric power demand will have a peak in day time and low consumption in night time, while the power demand of the LNG plant is almost constant due to its nature.

Therefore, the concept to combine the LNG plant with power plant will lead the electrical power cost to inexpensive due to the high availability of the power plant.

1. Basis for Study

As the basis of the study following plant configuration was assumed;

LNG Plant: 6.9 MTA, metric ton per annum
The maximum electrical power demand other than LNG plant:
400MW @ 45deg.C ambient temperature.
The average load of power demand other than LNG plant:
70%
Plant Location: Middle East
Design Ambient Temperature for LNG Plant:
29 deg.C

Economic evaluation basis

Feed Gas: Typical middle east gas, sour, contains hydrogen sulfide
Feed Gas Cost: 0.5 -1.0 \$/MMBtu, HHV
Fixed Charge Factor: 15%

2. Combination Feature

Following items were considered for the combination of the LNG plant and the power plant.

Elimination of Power Generation of LNG Plant

The power generation unit is eliminated, since the power plant located adjacent to the LNG plant can supply a reliable electrical power, although almost LNG plants are stand alone and the electrical power is generated by gas turbine and/or steam turbines inside of the plant. To keep the availability and reliability of LNG plant, emergency power generation facility should be still kept inside of the plant.

Prime Mover

Most LNG plant is stand alone and the refrigeration compressor is driven by steam turbine or gas turbine. Recent LNG projects have used gas turbine drivers although some expansion projects still apply steam turbine drivers. The thermal efficiency improvement and ease of startup give gas turbine drivers some advantages compared with steam turbine drivers.

Recent LNG plant applied gas turbine driver:

Gas Turbine, Dual Shaft	Arun (ref.-1), NW Shelf (ref.-2), Qatar Gas (ref.-3)
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Gas Turbine, Single Shaft	Kenai (ref.-4), MLNG-2 (ref.-5)
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The electrical power supply from the power plant adjacent to the LNG plant will replace the gas turbine driver or steam turbine driver to motor.

Fuel Gas to Power Plant

From view point of clean air of the area, the sulfur emission to environment should be minimized and the fuel gas to the power plant can be extracted from pre-treating section of the LNG plant.

Cooling Water Intake

The combined cycle requires a large amount of sea water for the steam cycle of the combined cycle and the requirement will be comparable to that of LNG plant. Therefore the cooling water intake can be combined, although the supply pump and lines should be dedicated to each plant, considering the reliability.

Steam Requirement of LNG Plant

LNG plant usually needs steam as heating media for acid gas removal unit and reboiler duties for fractionation, therefore cogeneration cycle application will contribute the plant efficiency.

However, the steam system trip will have a serious affect for LNG availability of LNG plant, since the steam system trip cause the total liquefaction train shut down including acid gas removal unit and the restart will take longer time. Therefore in this paper, the steam system combination was not considered.

3. Plant Scheme

LNG Plant Scheme

The LNG plant consists of typical three(3) trains with supporting utility facilities and LNG storage and loading facilities suitable for 125,000 m³ LNG tanker loading. The C3-precooled MR process of APCI, Air Products and Chemicals Inc. is assumed as liquefaction process. The typical flow scheme is shown in Fig. 1.

The liquefaction process applies two refrigeration systems, C3 and MR, mixed refrigerant. The propane, C3 is used as precooling of the feed gas and the MR. The C3 refrigerant system applies three(3) refrigeration levels. The C3 vapors from the evaporators are compressed by C3 compressor and cooled and condensed by cooling water. The MR is used for final cooling of the feed gas using spool wound heat exchanger. The vapor from the spool wound heat exchanger is compressed by MR compressors and then cooled by cooling water and C3 refrigerants. The power requirement ratio of C3: MR is 1:2 to3.

Typical configuration was shown in Fig. 2, where one GE Frame 5 is applied for C3 compressor and three(3) GE Frame 5's are applied for MR compressors.

LNG Plant Size: 2.3MTA x 3Train

The refrigeration compressor of each train

C3: 27 MW

MR: 64 MW

The LNG plant will consume

Refrigeration Compressors: 91MW x 3=273MW

Others: 127

Total 400

The refrigeration compressors are driven by motors instead of mechanical drive gas turbines. Excluding the emergency power, the electrical power will be supplied from the adjacent power plant.

Power Plant Scheme

Two cycles were considered; Simple Cycle
 Combined Cycle

Simple Cycle, SC

A schematic diagram for a simple cycle, single shaft gas turbine is shown in Fig. 3. Air enters the axial flow compressor at ambient conditions. Since these conditions vary daily, seasonally or for site, A standard condition is considered for convenience. The standard conditions used by the gas turbine industry are 59F (15C), 14.7 psia (1.013 bar) and 60% relative humidity, which are established by the International Standards Organization (ISO). These conditions are frequently referred to as ISO conditions.

Air entering the compressor is compressed to some higher pressure. No heat is added; however, the temperature of the air rises due to compression, so that the air at the discharge of the compressor is at a higher temperature and pressure.

Upon leaving the compressor, air enters combustion system, where fuel is injected and combustion takes place. The combustion process occurs at essentially constant pressure. The combustion mixture leaves the combustion system and enters the turbine.

In the turbine section of the gas turbine, the energy of the hot gases is converted into work. This conversion actually takes place in two steps. In the nozzle section of the turbine, the hot gases are expanded and a portion of the thermal energy is converted into kinetic energy. In the subsequent bucket section of the turbine, a portion of the kinetic energy is transferred to the rotating buckets and converted to work.

Some of the work developed by the turbine is used to drive the compressor, and the remainder is available for useful work at the output flange of the gas turbine. Typically, more than 50% of the work developed by the turbine sections is used to power the axial flow compressor.

When the feed gas cost is inexpensive, the simple cycle will be economical, since the unit plant cost per kW will be less expensive than the combined cycle, although the thermal efficiency of simple cycle is much less than the combined cycle.(ref.-6)

Typical Designation:

The power plant will be consist of simple cycle of six(6) of GE Frame -7FA equivalent. For example

Designation: PG7231FA

Thermal Efficiency(ISO): 36%

Performance. (ref.6)

<u>Site Temp. deg.C</u>	<u>Net Plant Power, MW</u>	<u>Heat Rate Factor</u>
15	167	1.000
29	153	1.025
45	147	1.053

Combined Cycle, CC

A typical simple-cycle gas turbine will convert 30 to 35% of the fuel input into shaft output.

The combined cycle is generally defined as one or more gas turbines with heat-recovery steam generators in the exhaust, producing steam for a steam turbine generator, heat-to-process, or a combination thereof. Fig. 4 shows a combined cycle in its simplest form. Very high utilization of the fuel input to the gas turbine can be achieved with some of the more complex heat-recovery cycles, involving multiple-pressure boilers, extraction or topping steam turbines, and avoidance of steam flow to a condenser to preserve the latent heat content. Attaining over 80% utilization of the fuel input by a combination of electrical power generation and process heat is

not unusual. Combined cycles producing only electrical power are in the 50% to 60% thermal efficiency range using the more advanced gas turbines. (ref.-6)

Typical Designation:

The power plant will be consist of combined cycle of four(4) of GE Frame -7FA equivalent. For example;

Designation: S107FA

Gas Turbine: PG7221FA

HRSG, Heat Recovery Steam Generator: reheat, unfired type

Thermal Efficiency(ISO): 55%

Performance: (ref.-7)

<u>Site Temp. deg.C</u>	<u>Net Plant Power, MW</u>	<u>Heat Rate Factor</u>
15	253	1.000
29	237	1.001
45	215	1.002

4. Technical Review for the LNG Plant

Compared with stand alone LNG plant, following were reviewed for the combined case.

Synchronous Motor Application

There has never been applied such a big motor driver for the refrigeration compressor of LNG plant. Since there is no induction motor of such size in the market, the driver should be synchronous motor which is basically same construction feature with power generator which has a vast market for such size. There is a few application of synchronous motor for gas compressor for such size by ASEA BROWN BOVERI, ABB.(ref.-8)

For this synchronous motor application, following points were reviewed;

Startup Device:

During the start up of the compressor and the driver synchronous motor, to increase the rotating speed to the synchronous speed against a big torque caused by the compressor, a gradually increased frequency current is introduced from the static frequency converter provided into the synchronous motor. To minimize the start up torque, the compressor is started in reduced suction pressure. After getting the synchronous speed using the variable frequency current from the static frequency converter, the main bus is connected to the synchronous motor, and then the suction pressure increased to normal operating condition, making up the hold up.

The capacity of the static frequency converter was estimated as around 8MW.

Constant Speed for Refrigerant Compressor:

The compressor is driven by synchronous motor, therefore the speed is constant. The compressor control is different from the common variable speed gas turbine driver. The MR compressor flow rate can be controlled by the hold up of the refrigerant.

If the suction temperature of the C3 compressor needs to be constant, it will be controlled by the propane compressor discharge pressure which is controlled by the acting surface area of the propane condenser against the temperature variation of the cooling water or air.

Extra Production

The power plant can supply the demand in case of ambient temperature of 45 deg.C and this will result over 5% extra production compared with stand alone case.

Reliability and Availability Consideration

The reliability of the LNG plant is mainly depend on the gas turbine driver of the power generator for the combined case, while the reliability of the LNG plant is mainly depend on the gas turbine driver in case of stand alone case. The availability of the power plant will be over 90% and the scheduled shut down will be around 5%. The scheduled shut down of the power plant will be incorporated with LNG plant maintenance program, minimizing the LNG plant unavailability.

Therefore, the availability of LNG plant was taken as 90% for this study as well as the stand alone case.

5. Economic Analysis

Based on above, the cases are defined as follows.

Definition of Case

The stand alone case was also evaluated for the comparison with the combination of LNG plant and the power plant.

The gas turbine cycle was considered for the power plant considering the recent high availability and the high thermal efficiency. Two cycle i.e. simple cycle, SC and combined cycle, CC were considered .

Study Cases:

Combination;	Stand Alone	Stand Alone	Combined	Combined
Gas Turbine;	SC	CC	SC	CC

The economic evaluation was made for the feed gas cost of 0.5\$/MMBtu and 1.0 \$/MMBtu. Plant costs were estimated as follows based on appropriate basis.

LNG Plant Cost: Stand Alone: 2,000 million \$
 Combined Case: 1,900million \$

Power Plant Cost: Combined Cycle: 600\$/kW
 Simple Cycle: 450 \$/kW

Case Study Results

The LNG cost is shown in Table-1. The table shows the combined case will have no cost difference against the stand alone case, although the extra production will make profit if the LNG market can absorb it.

The electrical power cost is shown in Table 2 and Fig. 5. The table shows the combined case will have 0.3-0.4 cents/kWh cost merit against the stand alone case. The combined cycle, CC will not have a cost merit for simple cycle for this feed gas cost range, although CC will have an advantage for the feed gas cost above 1.0 \$/MMBtu.

Table-1 LNG Cost, \$/MMBtu

	<u>Stand Alone</u>	<u>Stand Alone</u>	<u>Combine</u>	<u>Combine</u>
GT Cycle	SC	CC	SC	CC
Feed Gas 0.50 \$/MMBtu	1.68	1.68	1.68	1.70
Feed Gas 1.00 \$/MMBtu	2.26	2.26	2.25	2.25

Table-2 Electrical Power Cost, cent/kWh

	<u>Stand Alone</u>	<u>Stand Alone</u>	<u>Combine</u>	<u>Combine</u>
GT Cycle	SC	CC	SC	CC
Feed Gas 0.50 \$/MMBtu	2.1	2.4	1.8	2.1
Feed Gas 1.00 \$/MMBtu	2.7	2.8	2.4	2.4

6. Conclusion

The concept to combine LNG plant with power plant was confirmed to have economical advantage compared with the stand alone case from view point of LNG cost and electrical power cost for the range of the feed gas cost 0.5-1.0 \$/MMBtu.

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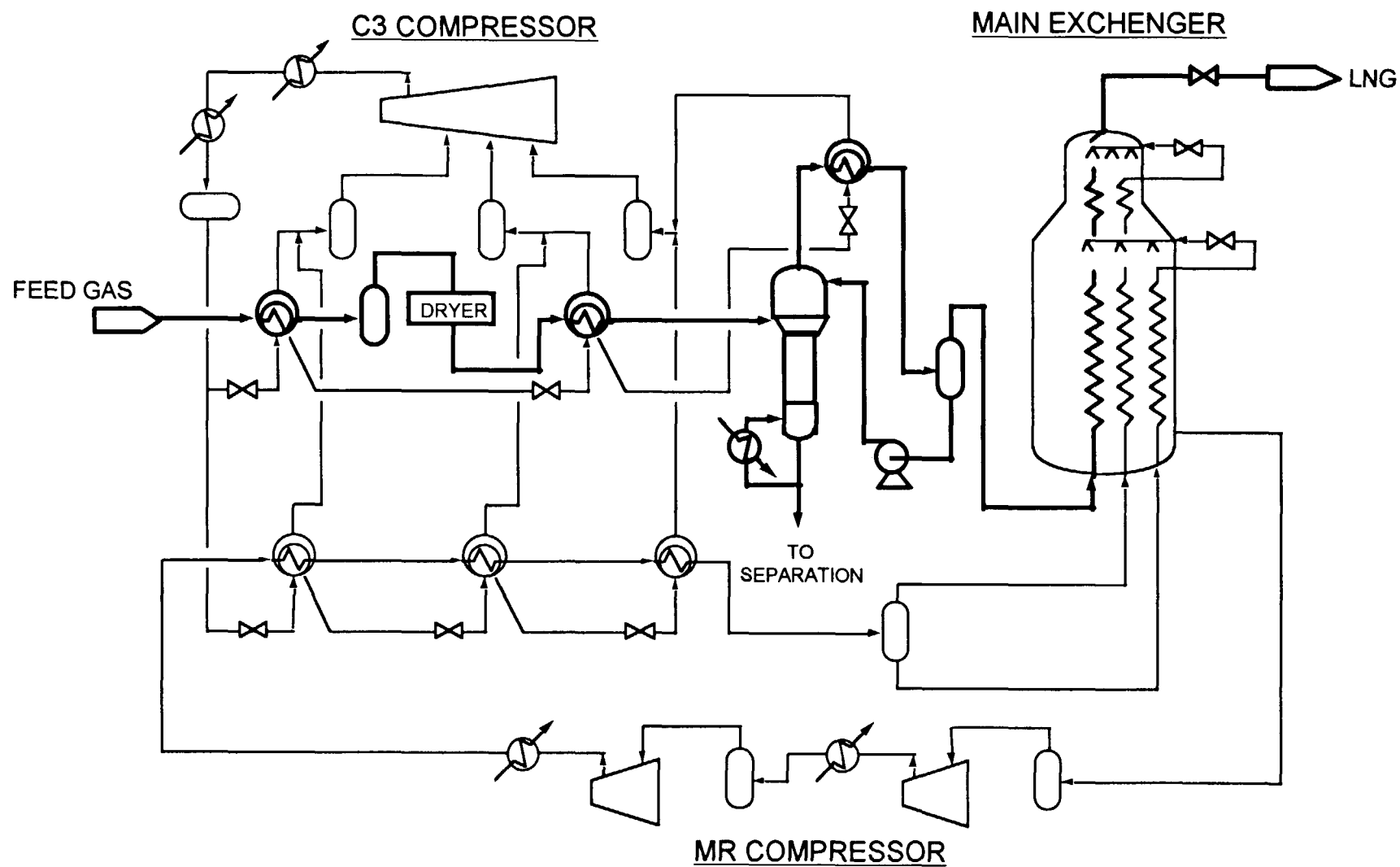
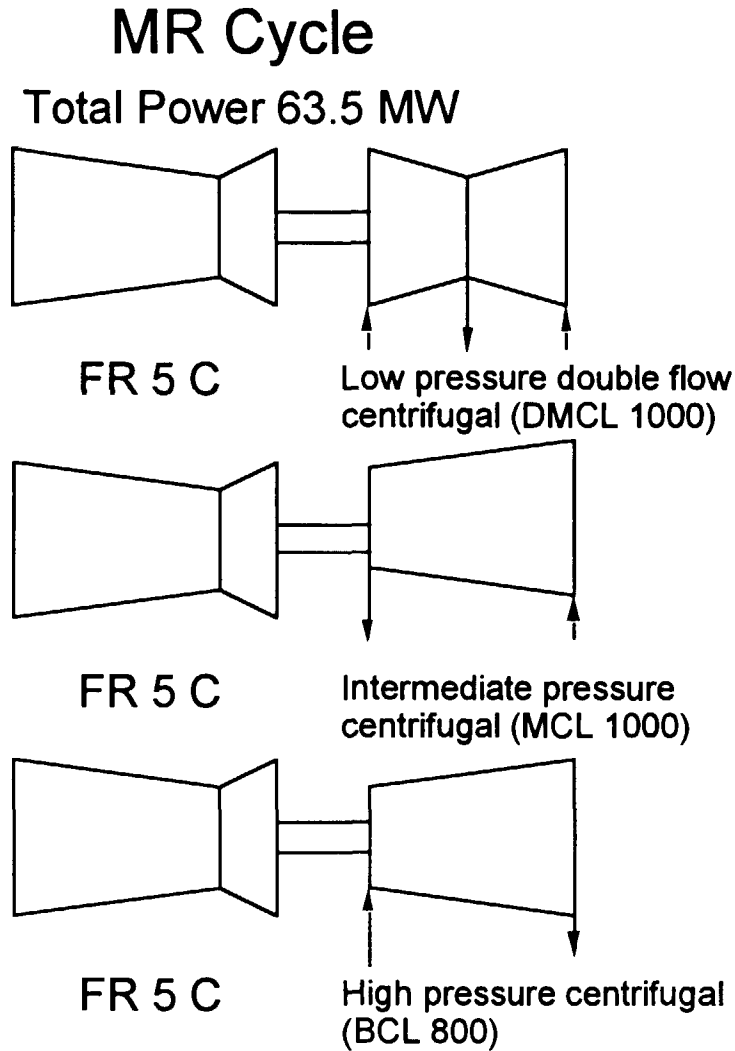


Fig. 1 C3-MR (APCI) Process Scheme



() Nuovo Pignone standard designation

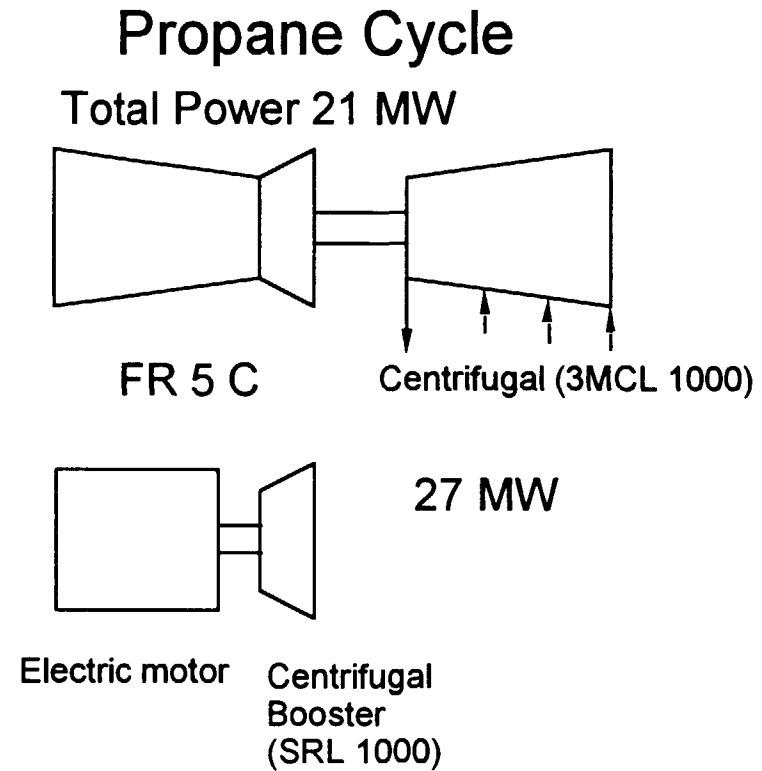


Fig. 2 QATARGAS 2.3 MTA Refrigeration Compressor Scheme

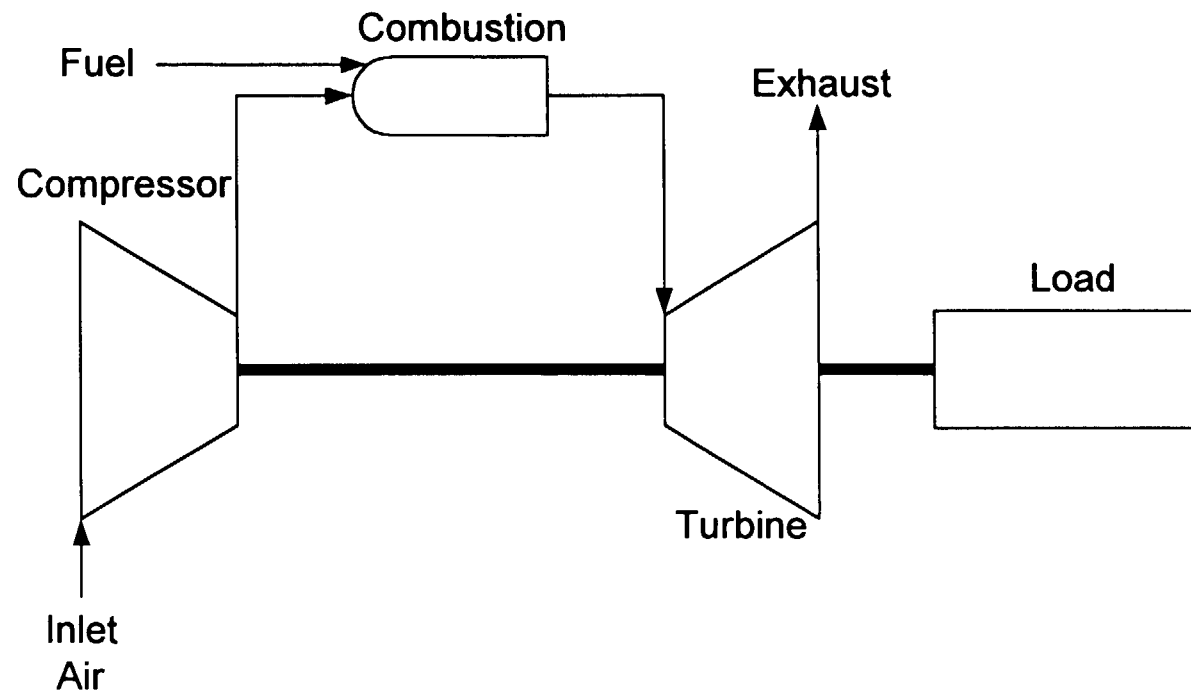


Fig. 3 Simple-cycle, single-shaft gas turbine

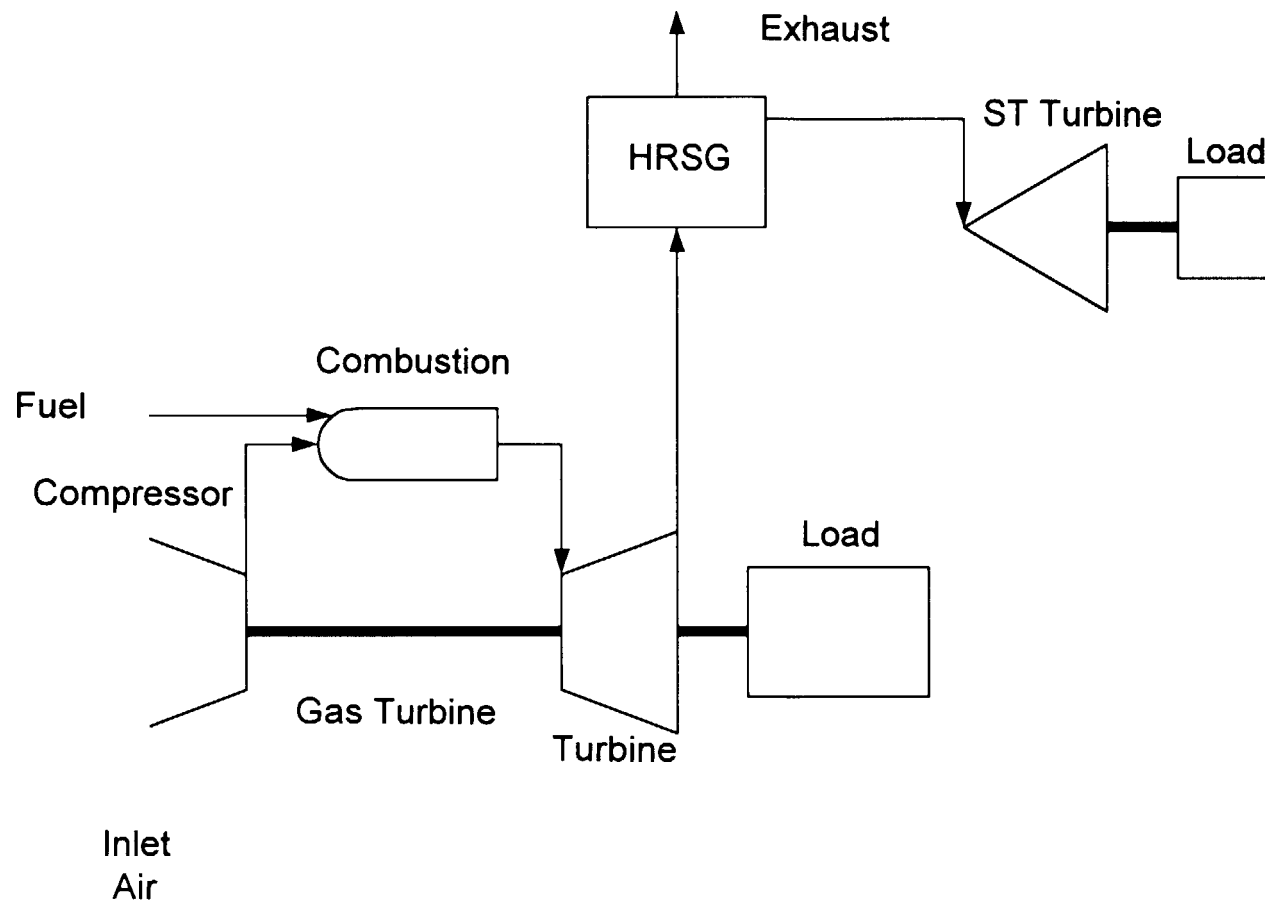
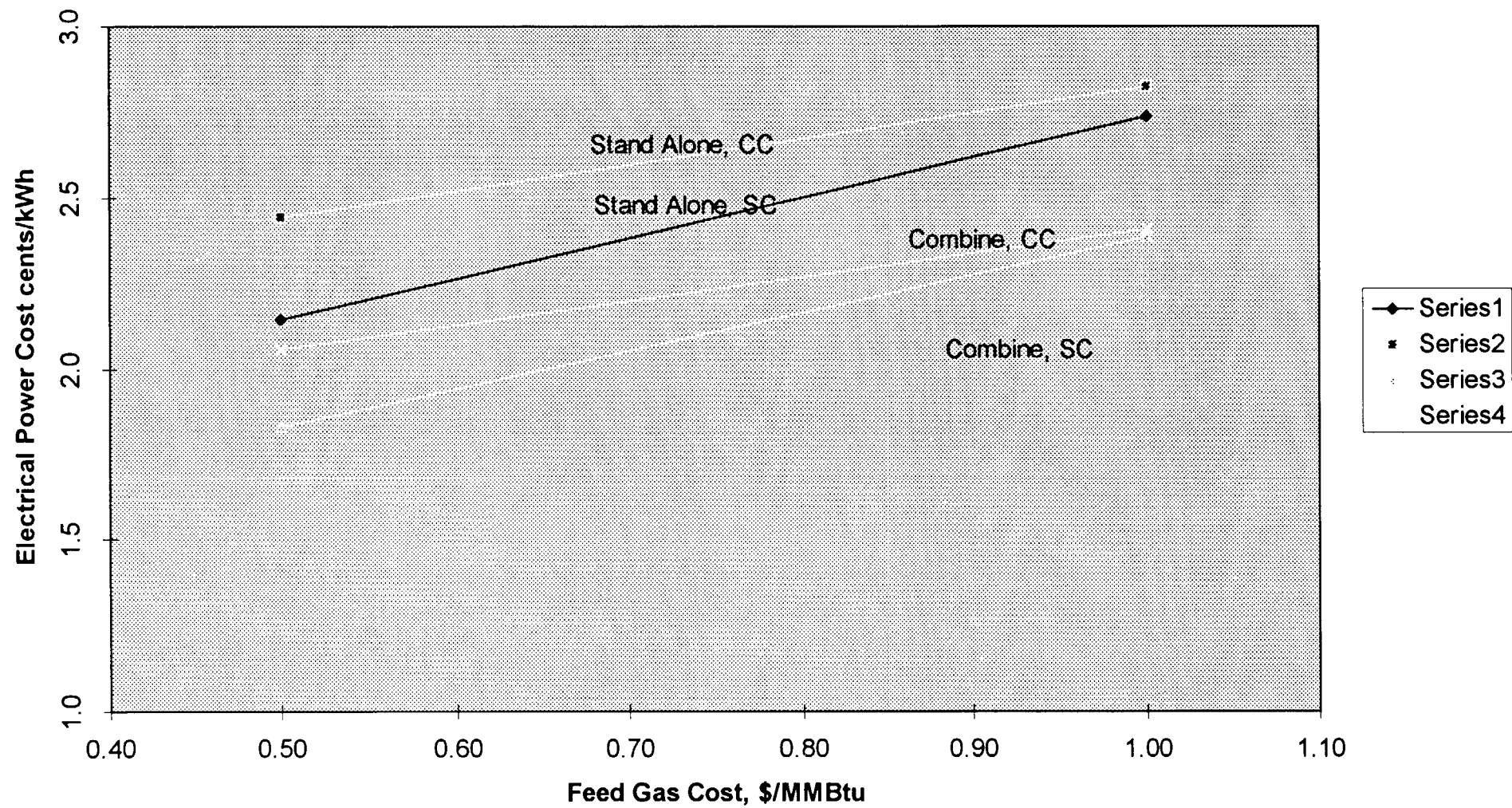


Fig. 4 Combined cycle

Fig. 5 Electrical Power Cost vs. Feed Gas Cost



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“Middle East Gas : Prospects & Challenges”

Session (7)

Natural Gas Demand in Emerging Markets

CHAIRMAN

Jerry R. Schuyler

Regional Vice President & Managing Director,

ARCO,

U.A.E.



“Middle East Gas : Prospects & Challenges”

Session (7)

Natural Gas Demand in Emerging Markets

Paper No. (7-1)

The GCC Gas Pipeline

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QATAR



“Middle East Gas : Prospects & Challenges”

Session (7)

Natural Gas Demand in Emerging Markets

Paper No. (7-2)

Prospect for Middle East Gas in India

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“Middle East Gas : Prospects & Challenges”

Session (7)

Natural Gas Demand in Emerging Markets

Paper No. (7-3)

Natural Gas Demand in Thailand

Chaichaream Atibaedya

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THAILAND

NATURAL GAS DEMAND IN THAILAND

Thai LNG Power Corporation Limited

Abstract

Natural gas has been introduced in Thailand since 1981 with the initial flow of 200 mmscfd, but today it is reaching almost 1,500 mmscfd, and it is also forecasted to continue rising in long term by the reasons of national economic growth which resulted in rapid increase in power demand together with Combined Cycle technology improvement and concern for the environment.

To satisfy the ever-rising demand, PTT has planned to import natural gas from neighboring countries, known as pipe gas, and import natural gas in the form of liquefied natural gas or LNG. These activities will provide more flexibility to Thai market and also increase the security of gas supply system.

Power generation is the major consumer of natural gas. However, natural gas and LNG still have to compete with other alternative fuels such as coal, Orimulsion and fuel oil.

To date, PTT has established TLPC for constructing, maintaining and operating the Receiving Terminal. And this achievement is only the first step of PTT in the LNG business.

Introduction

Natural gas has been introduced in Thailand since 1981 by Petroleum Authority of Thailand (PTT) which constructed the main pipeline for delivering the domestic gas in the Gulf of Thailand to customers, mainly power plants in the eastern region, at the initial flow rate of 200 mmscfd. With the government policy in developing the country toward an industrialized economy which has led to a rapid increase of energy consumption, especially electricity, today natural gas demand has been boosted to almost 1,500 mmscfd and it is estimated to reach around 3,000 mmscfd and 4,000 mmscfd in the year 2000 and 2005 respectively. This is mainly for power generation. To satisfy this ever-rising demand, PTT has planned to import natural gas from neighboring countries starting in the year 1998, and also to import LNG starting in the year 2003.

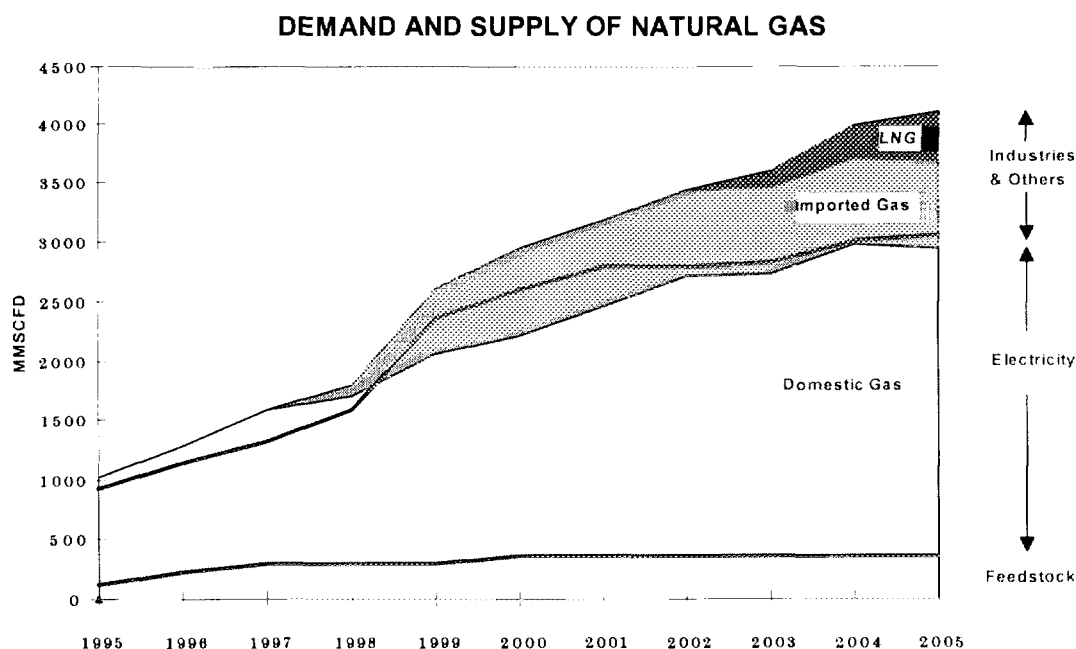


Figure 1 - Demand and Supply of natural gas (1995 - 2005)

Power Generation

Power generation sector is the major consumer of natural gas. It is still forecasted to be the main user of natural gas in the future because of the improvement in Combined Cycle technology and the increasing awareness of environment.

In the past the Electricity Generating Authority of Thailand (EGAT), a state enterprise, had maintained the monopoly on electricity generation. But to keep up the expansion of the generating capacity with the same pace of the electricity demand which results to increase in investment in public sector, the government had decided to privatize EGAT and promote private sector to participate on the power generation starting with selling the Rayong power plant to a private company, Electricity Generating Public Company Limited (EGCO) in the year 1994, and calling for bids on Independent Power

Producer (IPP) of 4,100 MW (for the period of 1999-2004) in the year 1995. After that it is estimated the demand for IPP will be around 1000 MW or equivalent to 140 mmscfd of natural gas each year from year 2005.

EGAT'S PLAN FOR POWER GENERATION

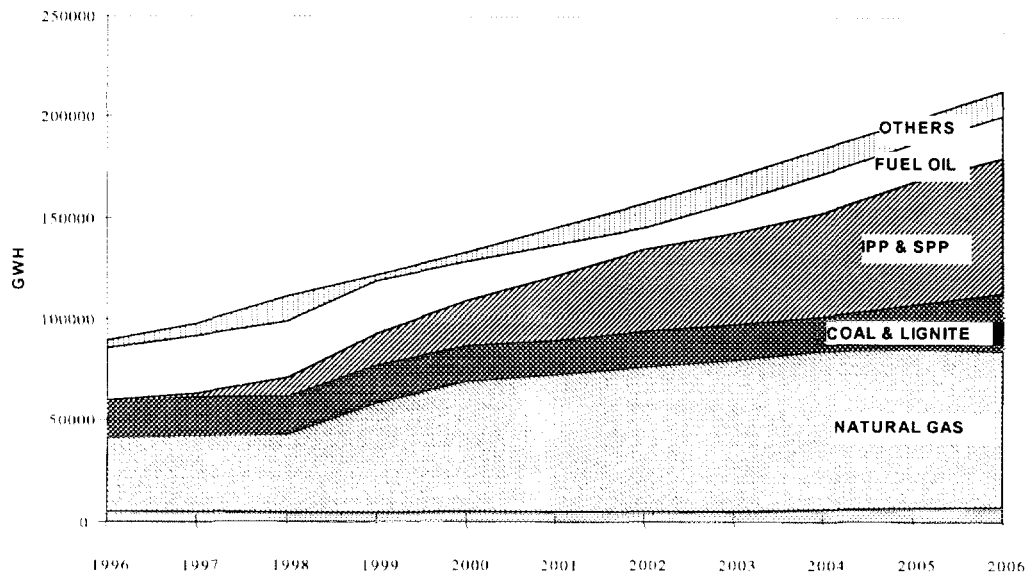


Figure 2 - EGAT's Plan for Power Generation

Natural Gas Market

Unlike Japan, Korea and Taiwan, Thailand has its domestic gas and is surrounded by countries which have plenty of gas reserves including Myanmar, Malaysia, Vietnam, Cambodia and Indonesia. It has more flexibility than the mentioned far east countries for the selection of natural gas supply sources.

Due to the domestic gas resources are mainly small fields and will be depleted within 10 years, to maintain a stable long term gas supply and increasing security of gas supply system, the government of Thailand, through PTT, has decided to diversify natural gas supply source by introducing LNG instead of relying only on pipe gas. The imported LNG is targeted to be used in IPP, Small Power Producer (SPP), new industries, and supplementary demand of EGAT together with remaining pipe gas as feedstock and firm demand of EGAT.

According to the announced IPP's proposal, EGAT did not specified the magnitude of electricity produced from natural gas, coal or other fuels. It said that the IPP's bid would be selected based on the criteria emphasized on the generation cost. Therefore the power plant using natural gas which produces less polluted emission than power plant using other fuels may not be selected if its generation cost is higher. The achievement of this IPP or natural gas demand creation would depend significantly on the price and condition of the LNG deal.

Many discussion had been held, and as you knew, PTT had signed the Memorandum of Understanding (MOU) without any exclusivity with Ras Laffan (RLLNG), Qatar, in year 1995. Later on, PTT had discussed with Oman LNG (OLNG), Oman, and found out that the OLNG's conditions had better conforming with Thai market characteristic than the other. Therefore in August 1996, PTT has signed Heads of Agreement (HOA) with OLNG for the delivery of LNG up to 2.2 million tons per annum starting in year 2003. It is expected that the Sale and Purchase Agreement (SPA) will be signed around the first quarter of 1997.

In addition to the first imported LNG from OLNG, PTT has planned for importing another million ton of LNG in year 2005. This increasing demand will depend on the availability of domestic gas and gas from neighboring countries, as well as the market situation.

Thai LNG Power Corporation Limited

For importing LNG, PTT had established a private company named Thai LNG Power Corporation Limited (TLPC) in year 1995 for constructing, maintaining and operating the Receiving Terminal which will be located in Rayong province, the eastern part of Thailand.

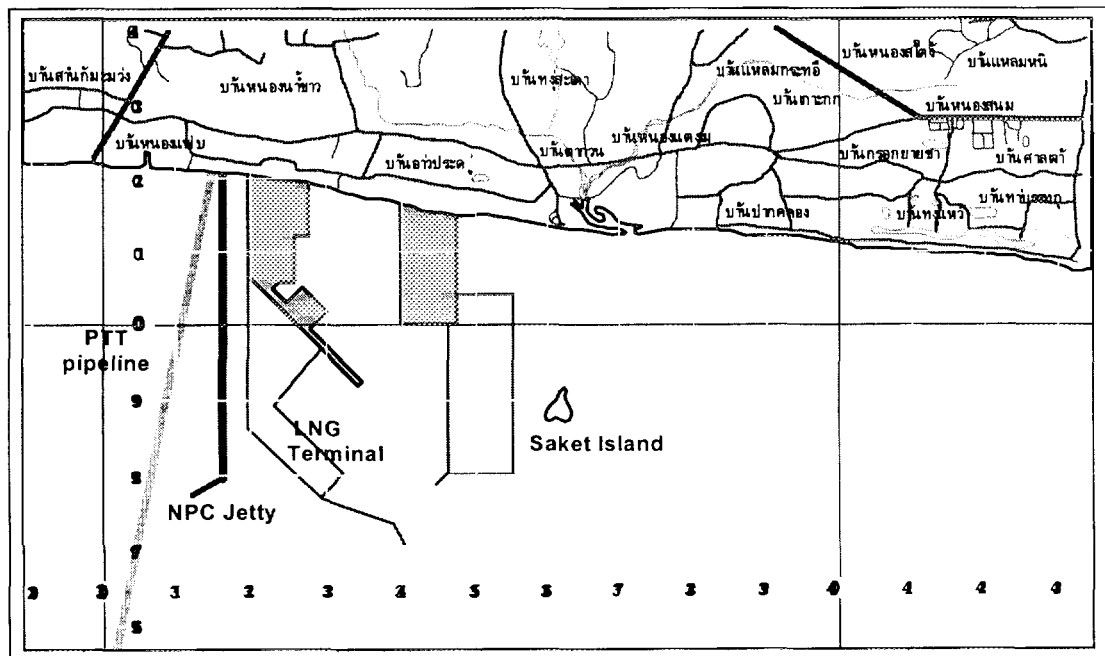


Figure 3 - The Location of Receiving Terminal

The Receiving Terminal will be constructed on reclaimed land with an initial capacity of two storage tanks and a jetty. It can be expanded up to six storage tanks and two jetties. And the estimated budget is around 700 million US\$.

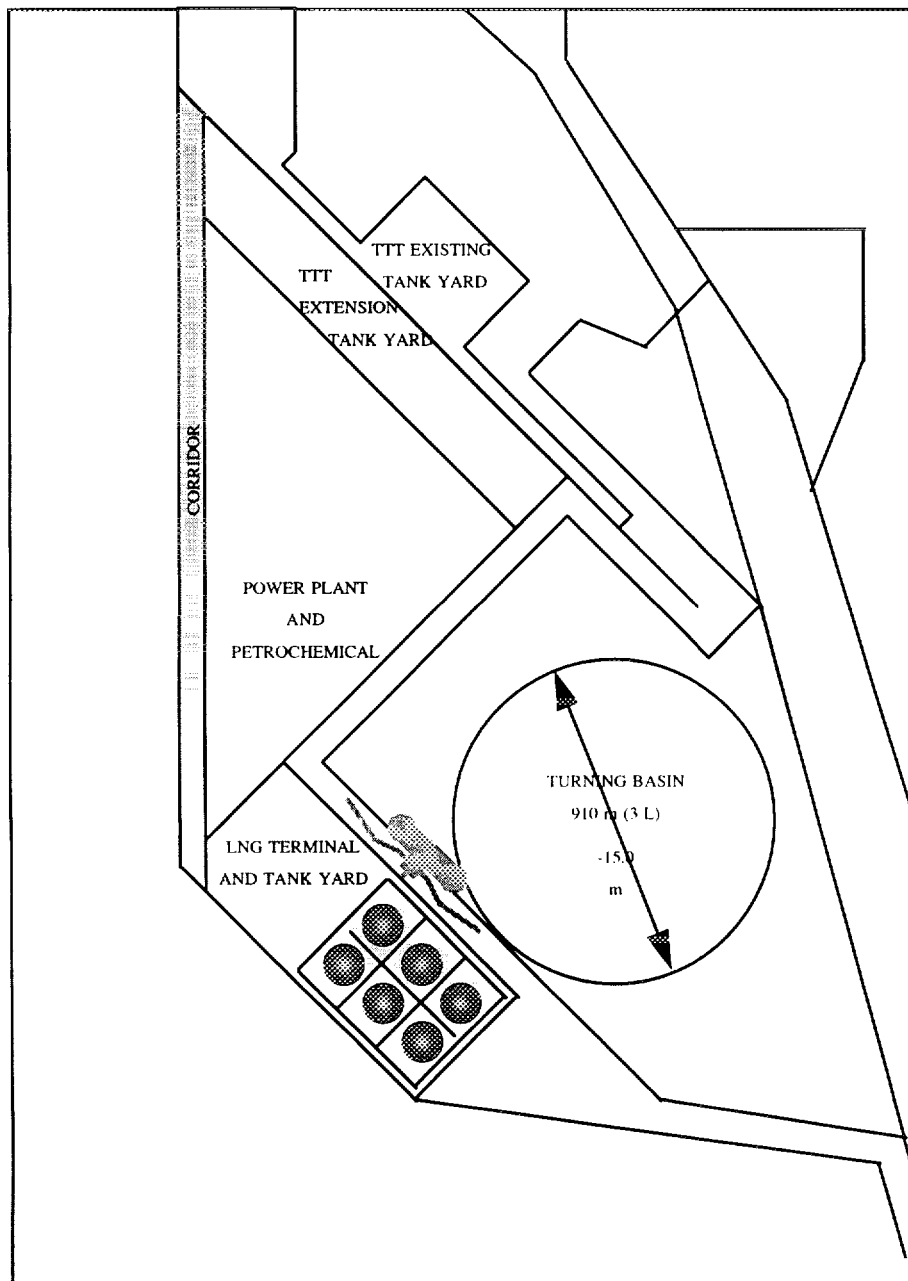


Figure 4 - The Receiving Terminal Layout

As One of the Emerging Markets

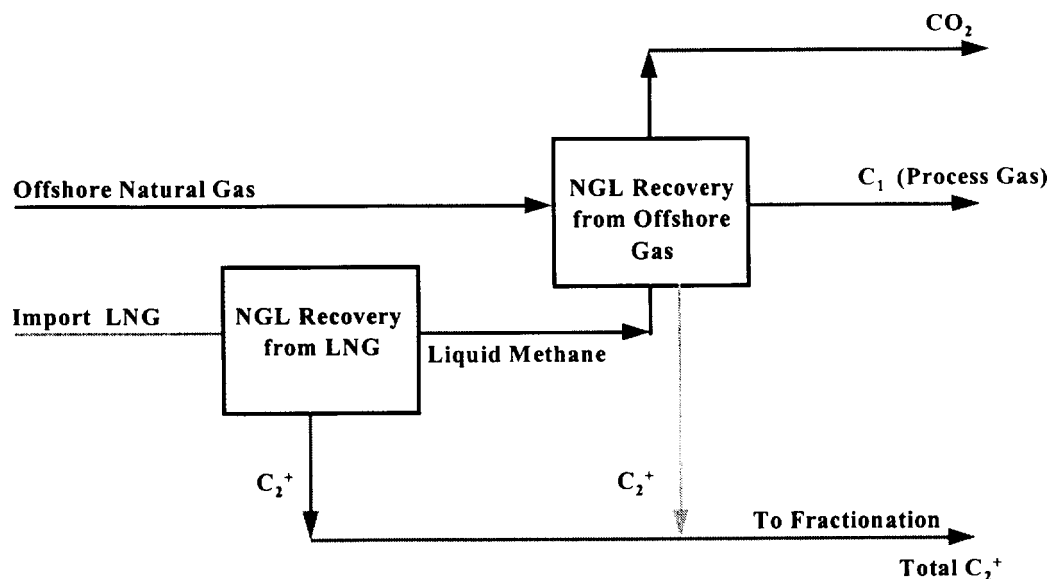
Thailand is one of the countries in the region with a rapid growth of natural gas demand. To meet this demand Thailand will import natural gas from neighboring countries through pipeline and LNG. In addition to meeting the demand requirement, LNG will provide the country with secured and diversified of natural gas supply sources, back up system in case of emergency as well as environment friendliness fuel.

The difficulties that new LNG buyers may encounter are high price of LNG and lower priority consideration compared to that given to existing buyers as suppliers envisage the higher risk. Even though PTT is a new comer in the LNG business, its experience in natural gas business and its status as a state enterprise will provide the suppliers confidence of government support and financial strength.

To better enhance economic justification of LNG importation, the utilization of cold energy is worth consideration. There are several alternatives for using the cold energy such as air separation, power generation and hydrocarbon (C_2^+) extraction from offshore pipeline gas and LNG. The C_2^+ extraction from natural gas by using cold from LNG is a unique and new approach for Thailand. Every one million ton of LNG can provide cold energy to separate C_2^+ from natural gas 270 MMCFD and LNG which will yield approximately C_2 200,000 tons per year, C_3 and C_4 260,000 tons per year and CO_2 292,000 tons per year. Furthermore, LNG can be utilized as peak shaving, remote industries and natural gas for vehicle (NGV) in the remote area where there is no natural gas pipeline network available by using LNG truck and satellite station.

One or more of the above LNG applications may assist new LNG buyers in challenging LNG importation to be in reality.

Hydrocarbon Extraction from LNG and Offshore Natural Gas





“Middle East Gas : Prospects & Challenges”

Session (7)

Natural Gas Demand in Emerging Markets

Paper No. (7-4)

Natural Gas Demand in Emerging Markets

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and Production, British Gas
U.K.**

Natural Gas Demand in Emerging Markets

Edward Walshe
Regional Managing Director, BG plc

Summary

The key requirement for the development of a gas industry in an emerging market is to have creditworthy buyers. Historically these have been major utilities, such as gas companies in Japan, able to commit to long-term, take or pay contracts for substantial volumes of gas. More recently, gas-fired power generation has provided the base-load needed to underwrite the large investments that gas projects require. In a changing world, these arrangements are getting more difficult to secure.

As privatization becomes more popular, governments are becoming less willing to provide state guarantees to back up gas purchases. As competition develops amongst utilities, power generators are becoming less able to commit to long term contracts. In short, risk is increasing. Furthermore, governments are becoming concerned to develop the use of gas beyond power generation - they want industry and commerce to use gas too and they see the potential benefits of the emerging uses : gas powered vehicles and air-conditioning.

What is required in these circumstances is a company willing and able to play the role of gas market developer. Such a company will understand that building a market requires more than just putting steel and polyethylene pipes in the ground. It is in a position to aggregate demand from smaller industrial and commercial customers, creating acceptable creditworthiness from companies which, individually, may be no better than mediocre credit risks. It will also know how best to supply a market through sophisticated contracts and optimising the design and use of infrastructure. Through these means, gas markets can developed to their full potential.

In return for playing such a role, a company will require stability of fiscal and economic terms. More than this though, it will expect that, in return, for taking on market risk, it will be allowed to benefit from some of the upside. Too often, governments want to regulate too early and too strongly, squeezing out any incentive for building a market.

Finally there are implications for supplier countries too. As the downstream market risks grow, then supplier countries who wish to develop their reserves are likely to have to share some of these market risks - but the rewards for those willing to do this are great.

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“Middle East Gas : Prospects & Challenges”

Session (8)

The LNG Chain : Technological Innovations and Cost Reduction

CHAIRMAN

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QATAR



“Middle East Gas : Prospects & Challenges”

Session (8)

The LNG Chain : Technological Innovations and Cost Reduction

Paper No. (8-1)

Reducing Capital and Operating Costs in Gas Processing, Liquefaction, and Storage

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**REDUCING CAPITAL AND OPERATING COSTS
IN GAS PROCESSING, LIQUEFACTION, AND STORAGE**

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Abstract

Reducing Capital and Operating Costs in Gas Processing, Liquefaction, and Storage

The LNG industry is unanimous that capital costs must be reduced throughout the chain, and especially at the liquefaction facility including associated gas processing and LNG storage. The Kenai LNG Plant provides an example of how both reduced capital and operating costs were attained. This paper will cover cost reduction strategies that can be applied to liquefaction processes in general, and will then focus on their realization in the Phillips Optimized Cascade LNG Process. A brief overview will be given of the current versions of Phillips' designs, with emphasis on the world-scale 2.5-3+ MPTA plant and its low \$/TPA. Consideration will be given to principles that should help to contain operating costs. The paper concludes that reduced LNG plant costs are attainable.

Introduction

The LNG industry is poised to enter the next millennium with both tremendous opportunity and challenges. The demand projections for LNG are well-known and encouraging (Figure 1). However, challenges also exist; such as more fragmented markets in the premium and mature LNG consuming countries, difficulties of establishing profitable LNG applications in emerging markets, competition with other energy sources, and competition between greenfield and incremental LNG projects.

Of course, LNG projects are by their very nature expensive due to the exotic metallurgy, large-scale equipment, and remote locations. Until fairly recently, the general trend of liquefaction plant costs expressed as \$/TPA, has been increasing (Figure 2). All concerned in the LNG industry agree that this trend must be arrested and reversed.

The Kenai LNG Plant Point Of Reference

The Kenai LNG Plant has been operating safely and profitably since 1969, and enjoys a reputation as both a low-capital-cost and a low-operating cost facility. The plant is located in Kenai, Alaska, USA, and currently exports about 1.3 MTPA to buyers Tokyo Electric and Tokyo Gas in Japan. The facility is jointly owned by Phillips Petroleum Company (70%) and Marathon Oil Company (30%), and is operated by Phillips.

The plant was designed by Phillips and Bechtel, and employs an early closed-methane-cycle version of the current Phillips Optimized Cascade LNG Process. In this process, three essentially-pure refrigerants are optimally cascaded; e.g. propane refrigerant condenses the ethylene refrigerant, which in turn condenses the methane. The plant was the first to use gas turbines to drive the refrigerant compressors, and was completed within 26 months after the start of site preparation.

At the time Kenai was the largest single-train plant in the world, and to this day remains the only reliable single-train baseload LNG Plant. In fact, reliability is such that the Kenai LNG Plant has never missed a shipload.

If valued in 1995 U.S. dollars, the Kenai LNG Plant would cost about \$200/TPA. The Kenai Plant also has a small O&M staff, which will be described later. Hence, Phillips' Kenai LNG Plant can serve as a useful reference for the LNG industry's efforts to contain costs.

General LNG Plant Cost Reduction Strategies

An unusual, but appropriate starting point for reducing LNG plant costs is acknowledging and using the superior process design tools that exist today. Steady-state process simulators and their improved physical properties packages can be benchmarked against existing plants and then run repeatedly to optimize designs. The cost implications of alternative approaches can be quickly evaluated. More exotic design techniques such as pinch analysis and dynamic simulation can be applied to fine-tune specific unit performance and to reduce design conservatism. Equipment, especially heat exchangers, can be more accurately rated today than in the past. The net result of all these design improvements is that today a plant can be "designed to capacity", with resulting capital savings.

The LNG industry seems to be moving towards optimum economies of scale in the range of 2.5-3+ MPTA per train. Train sizes smaller than this are dominated by relatively large fixed costs such as site preparation, LNG storage, and jetties. Train sizes much larger than 3+ MPTA (the exact cutoff is unknown) for most locations will probably observe reverse economies of scale; e.g. piping and valves will become prohibitively expensive, and large equipment will become unique and "one-off". Inherent in this exercise is selecting the gas turbines that will be used to drive the refrigerant compressors, as this is a major part of the plant's capital cost.

Other Value Improving Practices (VIP's) such as "process simplification" and "value engineering" can and should be implemented. Process functions can be combined, vessels and compressor stages may be eliminated, and other equipment may no longer be required. Non-traditional approaches in performing certain process functions can be brought in from other industries. New technologies can be evaluated. Of course, footprint reduction is a goal in itself, to the extent that safety, operability, and maintainability allow.

A new LNG plant design can also evolve as "fit for purpose". That is, the plant will comply with industry-accepted standards such as NFPA 59A, but arbitrary standards such as typically imposed by the operating company or technical lead might merit de-emphasis. Consideration should be given to using the EPC company's specifications. An atmosphere that encourages challenging the status quo ("why does it have to be this way?") should be maintained, and a cost reduction mentality should be emphasized throughout the design.

Successful application of "front-end loading" principles is also a key ingredient to reducing LNG plant costs. Site-specific engineering data must be collected quickly and applied to the design. Key operations and maintenance personnel must be assigned to the project and become integral to the design team. Hazard analyses should be performed as quickly as the design allows so that mitigation can be performed on paper instead of after the fact. The design must undergo constructability reviews. Proper application of front-end loading principles will reduce capital costs by ensuring that the design is "right the first time".

Lastly, proper execution of the design is also essential. Permitting, procurement, contracting, and construction strategies must all be formulated; all of which today's large EPC contractors are proficient. Procurement strategies might include alliances or similar alignment mechanisms with equipment suppliers, and early procurement of long-lead-time items. Project controls must be established. Finally, startup planning needs to be an integral part of the design and construction process.

The Phillips Optimized Cascade LNG Process

A block flow diagram of the Phillips Optimized Cascade LNG Process is shown on Figure 3. Feed gas conditioning uses standard processes which can be tailored for specific gas compositions; and typically includes inlet separation, acid gas removal, dehydration, mercury removal, and solids filtration. The clean feed gas is then chilled in the propane refrigeration cycle and condensed in the ethylene refrigeration cycle. The condensed feed enters the open-loop methane refrigeration cycle, which produces the LNG stream that goes to storage, a recycle stream that re-enters the liquefaction processes, and a fuel gas stream (note that a separate fuel gas compressor is not required). Of course, storage tank boil off vapors are recovered and integrated within the methane cycle.

The standard Phillips design utilizes a concept referred to as "2 train in 1 reliability" (Figure 4). The feed stream (including gas conditioning, liquefaction, and storage) are sized for 100% of design throughput, while each refrigerant cycle consists of two 50% turbo-compressor sets in parallel. That is, there are two propane, two ethylene, and two methane turbo-compressor sets. This technique improves single-train reliability while enabling a broad operating range (from 10% to 100+%) as described below:

<u>Description</u>	<u>Cause</u>	<u>Range</u>
Full Rate	Normal	90-100+ %
One Machine Down	Turbine Maintenance	70- 80 %
Half Rate	Shipping Delay	40- 55 %
Idle	Extreme Delay	10- 15 %

Phillips typically assumes a conservative 93% overall plant availability in its designs. This can be compared to the Kenai experience of plant availability exceeding 95%, gas turbine reliability exceeding 99%, and never missing a shipload in 27 years.

Phillips Efforts at LNG Plant Cost Reduction

Building upon the Kenai success, in the early 1990's Phillips and Bechtel commenced intensive efforts to reduce the capital cost of the Optimized Cascade LNG Process. Numerous process simulations were run to establish the optimum cost/performance balance over a broad range of ambient conditions and gas compositions. As an example, the cost or savings of adding or deleting compressor stages to the various refrigerant cycles were calculated and compared to the resulting LNG output or efficiency variation, resulting in the current standard compressor lineup. Power was balanced between the three refrigerant cycles (propane, ethylene, and methane), which enables the use of identical compressor drivers with resulting reductions in spare parts costs and maintenance expense. Where appropriate, techniques such as pinch analysis or dynamic simulator were used to fine-tune certain unit characteristics.

Phillips then selected gas turbine drivers for its world-scale plant (around 3 MTPA) that offered a number of competitive possibilities: For the maximally efficient version, the LM2500 was used as the design basis; and for the lowest \$/TPA version, the Frame 5 was employed. Both the LM2500 and the Frame 5 are well-proven in mechanical drive service, are priced in a competitive environment, and offer upgrade possibilities. Since both gas turbines are two-shaft machines, their starting motors are considerably smaller than the larger single-shaft machines, which has the added benefit of reducing the cost and complexity at the electrical plant. In addition, the use of parallel turbo-compressors reduces the cost of the flare system since the blocked discharge relief case is halved.

Process simplification techniques were applied to improve upon the Kenai-based design. Parallel vessels were eliminated wherever possible, certain refrigeration functions were combined, and numerous economizers were eliminated. In fact, one of the benefits of the open-cycle methane loop is the elimination of the separate fuel gas compressor. The net result is that for a plant twice the size of Kenai, efficiency is improved (typically 90-93%) while the cold boxes have been optimized to just two in the 500T to 600T range. Footprint discipline has been maintained to where the generic 3+ MTPA plant is not much larger than the Kenai LNG plant.

A "fit for purpose" approach was utilized throughout the design. Phillips' internal engineering standards served as useful references. Also, the EPC company's specifications were reviewed and used, but with an emphasis on allowing equipment vendor's standard equipment to comply as long as functional requirements were met. Of course, there were instances where ground could not be given, but in general, the atmosphere was one of open-minded intent to meet industry standards and government regulations.

Front-end loading principles were applied vigorously. The design effort, although generic in nature, was based upon a real site, with real ambient conditions, and a real gas composition. Feedback was obtained from the Kenai experience. Plant operations and engineering personnel were an integral part of the design team and participated in the process hazards analysis. Modularization was pursued where appropriate (although the overall plant is stick-built), and constructability reviews were held. The end result was a basic LNG plant design that costs significantly less than the industry paradigm.

Current Generation Of Phillips' LNG Plant Designs

As previously stated, Phillips has been working with Bechtel Corporation to offer the 1990's generation of the Optimized Cascade LNG Process. Phillips has spent over \$12,000,000 to complete numerous engineering studies including Front-End Engineering Design (FEED) packages for three "generic" plants. That is, a number of "real world" design assumptions have been made, engineering has progressed to the 20-25% level, equipment and services specifications have been written, and equipment and service competitive bids have been received as if a real project was to be executed. Subsequent studies have expanded the options available from the three base designs.

The three generic FEED packages are described as follows:

<u>Identifier</u>	<u>MTPA Range</u>	<u>Refrigerant Compressor Gas Turbine Drivers</u>
2.5	3.0-3.6	6 LM2500's or 6 Frame 5's
1.1	1.3	6 Mars 100's
1.1 Expand.	1.5-3.0	3 LM2500's now, 3 more LM2500's later

Common assumptions to all three generic FEED studies include:

- fairly lean inlet gas composition (approximately 96% C1)
- low inert gas concentration
- low acid gas concentration, trace H₂S
- 26°C design temperature
- fairly significant site preparations
- foundations require piling
- good local construction infrastructure
- air versus seawater temperature suitable for airfin cooling
- single-containment LNG storage tanks
- low-cost jetty

The scope of the FEED packages include design and installation of the following facilities; e.g. the entire LNG plant:

- gas conditioning
- liquefaction
- storage and loading
- utilities (self-sufficient)
- buildings

Assuming that the site has been selected, the FEED work (20-25% engineering) has been completed, acquisition of environmental permits is underway, and business activities proceed as planned, then going from "start" (project approval, EPC award, etc.) to making LNG can occur in under 36 months (Figure 5).

The "2.5" Plant

As stated previously, the "2.5" is a nominal identifier for the plant's LNG output in MTPA. Given the aforementioned design conditions and taking 100% of the design output (e.g. no derating for gas turbine maintenance, unplanned outages, or turnaround activities such as vessel inspection), the "2.5" plant actually has an LNG output of 3.0 MTPA for the aeroderivative (6 LM2500) case, and 3.6 MTPA for the industrial (6 Frame 5) case. The gas conditioning and liquefaction process were described previously. Included in the design are two 95,000 M³ single-containment LNG storage tanks, each with three in-tank loading pumps. A jetty complete with loading arms is also provided.

The plant complies with NFPA 59A, U.S. EPA environment regulations, and U.S. OSHA worker safety regulations. Appropriate safety systems such as fire, gas, and cryogenic liquid detection are included; along with emergency shutdown and various fire suppression systems.

Depending on whether the aeroderivative or the industrial version of the "2.5" is selected, the plant (e.g. gas conditioning, liquefaction, and storage) will have the following characteristics:

<u>Parameter</u>	<u>Aeroderivative</u>	<u>Industrial</u>
Refrigerant Gas Turbines	6 LM2500	6 Frame 5
Inlet Rate	455 MMSCF/D	556 MMSCF/D
LNG Output (100%)	3.0 MTPA	3.6 MTPA
Overall Plant Efficiency	92.5%	90.7%
Plantwide Electrical Load	16.5 MW	16.7 MW
2-Train-In-1 Reliability	Yes	Yes

The "2.5" is the world-scale flagship offering of the Optimized Cascade LNG Process, and can be designed and constructed in many locations for \$200 - \$250 per TPA. It should be noted that although this design makes a single-train projects reliable and profitable, the concept can also be applied to multi-train projects. That is, construction activities can be staggered and optimized to reduce overall costs on subsequent trains, while the initial train operates reliably.

Phillips is currently pursuing a single-train "2.5" LNG plant to develop the Bayu-Undan field, discovered in 1995 in the zone of cooperation between Australia and Indonesia. And of course, the Atlantic LNG (ALNG) consortium in 1996 selected the Bechtel/Phillips bid to construct a "2.5" plant in Trinidad.

Reducing Operating Cost

The Kenai LNG Plant has a reputation for low operating costs. An excellent process design, a "good" feedstock (99% C1) for making LNG, a highly-skilled workforce, and a good location are all parts of the equation. Total Phillips employee workforce at Kenai is about 50; more or less equally divided between plant operations, plant maintenance, offshore platform operations and maintenance (the platform is the source of the Phillips feedstock), and front office staff (management, engineering, administration, etc.). As an example of the low head count, on weekends there are typically only three people in the plant: a shift supervisor, and inside operator, and an outside operator.

How can this be translated to other locations? Phillips has not yet had this opportunity come to fruition regarding LNG. However, Phillips is no stranger to successfully operating safe, profitable, and efficient upstream and downstream business units outside of the USA. The following are guidelines that could be employed:

- Select technology that is appropriate for the region
- Design & construct on "operator-friendly" and maintainable facility; involve O&M personnel throughout
- Consider life-cycle costs
- Focus on startup throughout the design
- Develop operating procedures during design
- Hire and train national work-force early
- Assign experienced expatriate personnel to key positions
- Use contractors for non-core or intermittent services
- Respect the local culture and work practices, utilize their strengths

Phillips intends to apply the computerized process training methods developed at Kenai, and use Kenai as a training springboard, to improve operating consistency and reduce costs on future LNG projects.

Conclusion

The Kenai LNG Plant has operated safely, reliably, and profitably for over 27 years, and serves as a reminder that reduced capital and operating costs are attainable. There are many evolutionary design practices that can be applied to reduce the capital costs of today's LNG plants. Phillips and Bechtel have demonstrated their commitment in this regard as evidenced by the award of the ALNG Project. In addition, Phillips and Bechtel have recently announced the formation of a Global LNG Alliance, with a mission of reducing LNG plant costs. In conclusion, the LNG industry will enter the next millennium with the tools and the competitive arena to reduce capital and operating costs in the liquefaction portion of the LNG chain.

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“Middle East Gas : Prospects & Challenges”

Session (8)

The LNG Chain : Technological Innovations and Cost Reduction

Paper No. (8-2)

The PRICO Cycle : The Low Cost Alternative to LNG Production

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PRICO™ CYCLE: THE LOW COST ROUTE TO LNG PRODUCTION

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ABSTRACT

The PRICO™ cycle is a proven process for liquefaction of natural gas, both in large base load facilities and in small peak-shaving plants. Because PRICO™ uses only a single mixed refrigerant the process is simpler than any of the competing processes. This translates into fewer equipment services, less bulk materials and reduced construction hours. Further, the process uses only non-proprietary equipment which can be purchased from multiple vendors, thus ensuring competitive bids.

This paper gives a description of the PRICO™ process and its recent improvements. Specific areas where the process provides cost reduction are identified. In addition to fewer pieces of equipment, the use of plate fin exchangers, reduced use of stainless steel materials and the use of cold-box construction all contribute to reduced capital cost. Some of the operating advantages of the process are also discussed.

For a base load LNG plant it is expected that the PRICO™ process can reduce the installed cost of the liquefaction unit by about 25 percent.

INTRODUCTION

The high cost of liquefied natural gas facilities was a major reason why relatively few projects came to fruition in the 1970s and 1980s. In recent years the industry has made concerted efforts to reduce the unit cost of delivered LNG. This has required innovative solutions and improved project execution in all segments of the LNG chain.

The cost of the liquefaction plant is a large component of the overall cost of the LNG chain. Cost reductions in liquefaction plants have come mainly from "economies of scale": that is, process trains have become larger and larger. Whereas ten years ago a 2.5 million tonne per annum (MMTPA) train was considered "world scale", today single-train capacities of the order of 3.5 MMTPA are more common. The advent of large-capacity single-shaft gas turbine

drivers for the large process refrigeration compressors has been a key element in the development of large LNG trains.

The PRICO™ process (Poly Refrigerant Integrated Cycle Operation) licensed by Black & Veatch Pritchard offers the opportunity to further reduce the cost of natural gas liquefaction plants. It is based on a proven liquefaction cycle that uses fewer and simpler equipment than the competing cycles. Moreover, recent enhancements to the process have improved the thermodynamic efficiency of the PRICO™ process to a level equivalent to those of other processes.

The PRICO™ process is inherently modular in nature and unit train capacity can be easily adjusted to match available gas turbine drivers. Consequently, lower plant costs in terms of \$/tonne of LNG, are possible both for large train sizes and for the many special cases where smaller trains are still preferred.

The first base load application of the PRICO™ process was at the Sonatrach plant in Skikda, Algeria. The PRICO™ process has also been employed successfully in a number of smaller peak shaving plants. It is the only liquefaction process which has been used in both base load and peak shaving applications.

PROCESS DESCRIPTION

Following its involvement in a number of early cascade cycle LNG facilities, Pritchard developed a proprietary mixed refrigerant process for gas liquefaction, known as the Poly Refrigerant Integral Cycle Operation or PRICO™ process. This proprietary process, which is jointly owned with Kobe Steel Ltd., employs a single mixed refrigerant loop to accomplish the gas liquefaction. This refrigerant is a mixture of nitrogen and hydrocarbons ranging from methane to isopentane. Typically, refrigerant components except for nitrogen are extracted from the feedstock. Nitrogen is provided from an air separation unit. The process uses a single refrigeration compression system. The compressor can be a single case compressor with or without interstage cooling. The use of a single refrigeration system greatly simplifies the piping, controls and equipment arrangement for the liquefaction unit compared to other processes. The process cools the natural gas feed from ambient conditions to gas liquefaction temperatures and then subcools the LNG to minimize downstream flashing.

The process flow diagram in Figure 1 illustrates the simplicity of the process. This diagram shows a two-stage compression configuration. During compression, the gas from the first stage is cooled in an intercooler. The condensed liquid is pumped to the refrigerant condenser and joins with gas from the second stage.

After being cooled in the refrigerant condenser, the refrigerant gas and liquid are separated and supplied to the refrigerant heat exchanger as high pressure refrigerant. A separate supply of refrigerant gas and liquid makes it possible to achieve desired distribution at the refrigerant exchanger inlet. At the same time, control of the refrigerant composition is accomplished by adjusting the flow of liquid refrigerant out of the refrigerant separator. The composition of the circulating refrigerant can be changed by decreasing or increasing the inventory in the refrigerant separator. Thus the refrigeration system composition and operation can be adjusted and optimized while the unit is in operation.

The high pressure refrigerant flows downward along the full length of the heat exchanger and is cooled, condensed, and sub-cooled. The sub-cooled, high pressure refrigerant expands and cools through the J-T valve, and then enters the bottom of the refrigerant heat exchanger as low pressure refrigerant. It then flows upward counter to the high pressure refrigerant and feed gas, cooling and liquefying them, while the refrigerant itself is vaporized and superheated.

The pretreated feed gas enters the upper part of the refrigerant heat exchanger and is liquefied with low pressure refrigerant as mentioned above. The refrigerant exchanger is composed of brazed aluminum plate fin exchangers arranged in parallel to provide the desired production capacity. These exchanger modules make the process easily expandable and maintainable.

Based on the actual composition of the feed gas to be liquefied, heavy hydrocarbons should be removed in order to recover valuable heavy hydrocarbon byproducts as well as to prevent plugging due to solidification at cryogenic temperature. For this reason the feed gas is drawn out of the liquefaction exchanger at a specified temperature and pressure. After the condensed heavy liquid is separated, the gas is returned to the refrigerant heat exchanger where it is further cooled, liquefied and sub-cooled.

If the heavy liquid is of sufficient quantity, fractionation of this liquid into products including ethane, propane, butanes, and gasoline may be economically attractive. Products from the fractionation unit are used for refrigerant make-up.

The sub-cooled LNG exits the exchanger at around -144°C and full process pressure. This stream is then sent to LNG storage near -161°C and atmospheric pressure. Most facilities utilize an intermediate flash step prior to final pressure reduction to storage. This intermediate flash can help to preferentially remove nitrogen from the LNG product. Flash gas from this step is usually warmed, compressed, and used for fuel.

RECENT IMPROVEMENTS TO THE PRICO™ PROCESS

The PRICO™ process has been improved to increase its efficiency without sacrificing its simplicity and reliability. One of the changes which significantly improved the process efficiency is to raise the pressure of the HP multicomponent refrigerant. This requires a second stage of compression. However, the process still remains a single refrigerant loop. This change along with other improvements in the process results in the following savings:

- Reduction of refrigerant circulation rate.
- Improvement of the temperature differential between warm and cold streams in the cold box, especially at the coldest end, resulting in reduced exchanger surface area.
- Reduction of the number of cores required by about one third.

For a fixed compressor power, the improved PRICO™ process is expected to increase LNG production by over 35% when compared with the original process.

WHAT MAKES THE PRICO™ PROCESS COST EFFECTIVE

Factors that make the PRICO™ process more cost effective than the competing processes include:

- **Simplicity:** the process requires fewer pieces of major equipment, and this translates into a much simpler plant configuration
- **Inherently modular:** desired capacity can be achieved by adding parallel, identical liquefaction loops within a single large process train
- **Plate-fin Exchangers:** heat transfer for refrigerant chilling and gas liquefaction is done in non-proprietary aluminum plate-fin exchangers
- **Less Stainless Steel:** the sections of the process unit that require stainless steel materials of construction are very few. The refrigeration loop is all carbon steel except for the cold-box area
- **Cold-box Construction:** nearly all the cryogenic equipment is enclosed in cold-boxes. This minimizes expensive field construction, and also results in substantial savings on insulation costs
- **High purity refrigerants** are not required. This significantly reduces the fractionation equipment requirements
- **Conserves refrigerant** because the process is designed to hold the refrigerant. Even during a prolonged shutdown venting or pressure control of the refrigerant loop is unnecessary
- **Startups--both warm and cold--are quick and easy.** This is due to the conservation of refrigerants and the “cold-end down” configuration of the cold-box

These factors will be discussed below in greater detail.

Simplicity

Table 1 shows the count of major equipment services for a liquefaction unit using the PRICO™ cycle. For comparison, typical count for competing cycles is also indicated.

The use of a single mixed refrigerant loop, as opposed to the two or three refrigerant loops used by the competing processes, is the main reason for the reduction in equipment service count by over 50 percent. The addition of each refrigerant loop adds more “pots and pans” in the form of compressor suction drums, inter- and after-coolers, and heat exchangers.

The main advantage of the PRICO™ cycle is not related to the amount of heat to be transferred. With nearly equivalent thermodynamic efficiencies, all the processes extract similar quantities of heat from the natural gas, and reject similar amounts of heat to the environment. The uniqueness of the PRICO™ cycle is that all the heat transfer for refrigerant chilling and gas liquefaction is consolidated into a **single heat exchange service**. The quantity

of heat to be transferred is still very large--similar to the competing processes-- and multiple banks of parallel cold boxes are used. However, since these parallel boxes are all in the **same service** the total number of heat exchange services is greatly reduced when compared with the other cycles (See Table 1). A direct consequence of this is the opportunity for a much simpler plot layout and a drastic reduction in the amount of large diameter piping.

Table 1

MAJOR EQUIPMENT SERVICE COUNT

EQUIPMENT SERVICE	PRICO™ CYCLE	TYPICAL OTHER CYCLE
Minimum number of refrigerant compressors	1	3
Number of refrigerant suction drums	1	5 or more
High pressure liquid refrigerant receivers	2	2 or more
Precooling and liquefaction exchangers	1 (in parallel cold boxes)	7 or more
Number of compressor inter-, after-coolers, condensers, subcoolers	2	5
Refrigerant pumps	2	--
Total	9	22

The number of heat exchange services is directly tied to the number of refrigeration stages and the number of compressor suction drums. Each additional stage adds significantly to the cost in terms of large diameter piping, antisurge protection, instrumentation and control complexities, etc. We have confirmed through direct comparison cost estimates that the PRICO™ process, as a result of its simplicity, allows substantial reduction in bulk material costs. It follows that with fewer pieces of equipment and less bulks to install the construction costs will be less for the PRICO™ process than for its competitors.

Modular Design

A main component of any liquefaction process is the liquefaction exchanger(s). In the arrangement of this exchanger the PRICO™ process is inherently modular: larger capacities can be accommodated by adding additional cold boxes of identical design. The process also accommodates a wide range of gas turbine drivers for the refrigerant compressors. With only one refrigeration loop there is no need for "matching" drivers among the different refrigeration loops. Any set of feed gas conditions and compositions can be accommodated in a flexible manner.

The capacity of a single liquefaction unit is set by the size of the refrigeration compressor and driver. Table 2 illustrates typical gas turbine options and corresponding LNG production capacities. With a GE-Fr 7 gas turbine (at present the largest used in refrigeration service) a

single PRICO™ loop can produce up to 1.8 MMTPA of LNG. For larger train capacities additional refrigeration power is required, and there is more than one way to configure the additional compressors and drivers. A preferred option is to arrange them as parallel loops within a single process train. Using this parallel loop arrangement single train designs of over 3.7 MMTPA capacity have been confirmed. Figure 2 illustrates this arrangement.

Table 2

TURBINE OPTIONS WITH THE PRICO™ PROCESS

	<u>Frame 5</u>	<u>LM2500</u>	<u>LM6000</u>	<u>Frame 6</u>	<u>Frame 7</u>
Shaft Power, MW	24.2	20.5	32.5	31.9	69
Heat Rate, kJ/kWh	13020	9970	9400	11870	11660
LNG Prodn, MMSCFD	80 - 90	68 - 76	109 - 121	107 - 119	230 - 257
LNG Prodn, MMTPA	0.55 - 0.60	0.47 - 0.53	0.77 - 0.85	0.76 - 0.84	1.63 - 1.81

As shown in Figure 2, an increase in capacity of the overall liquefaction train is also accomplished in a modular fashion. With this approach the pretreatment section of the train can be sized for very large capacities, say 3.6 or even 5.4 MMTPA. The liquefaction section will consist of two or three parallel loops (each with a capacity of 1.8 MMTPA) integrated into a large process train of 3.6 or 5.4 MMTPA.

A major advantage of the parallel unit arrangement is increased plant availability. The shutdown, either scheduled or unscheduled, of any single compressor/driver will not result in total stoppage of production. LNG production in the other parallel loop(s) will continue uninterrupted.

Also, since the individual loops are of identical design the benefits of reduced engineering and procurement effort associated with the PRICO™ process are fully realized even when large plant capacities are desired.

Non-proprietary Heat Exchange Equipment

All heat transfer for chilling the refrigerant and for cooling/condensing the natural gas is done in non-proprietary aluminum plate-fin heat exchangers. Over the years the techniques for design and fabrication of these exchangers have advanced considerably, and these exchangers have been used successfully in numerous cryogenic gas processing applications, including LNG plants.

Several qualified vendors in different continents are capable of designing and fabricating these exchangers. This permits competitive pricing and considerable flexibility in purchasing schedule. As a result the PRICO™ process allows for a significant reduction in the installed cost of low-temperature and cryogenic heat exchange equipment.

Less Stainless Steel

With the PRICO™ process the use of stainless steel metallurgy is restricted to a small portion of the liquefaction unit. The entire compressor circuit, including the large diameter suction lines, are carbon steel. This is because the suction to the mixed refrigerant compressor operates close to ambient temperature. Also, the liquid refrigerant drums contain liquids of relatively high molecular weight and operate at ambient temperatures. Consequently, even under upset conditions the temperatures are sufficiently warm to allow the use of carbon steel materials.

A further advantage is the naturally “cold-end down” arrangement of the cryogenic exchanger. As a result of this, even during an upset or shutdown the exchanger maintains its natural temperature profile, and avoids a situation where the compressor suction becomes too cold.

The reduction in the amount of stainless steel translates into savings in equipment cost, piping material cost, and insulation cost.

Cold Box

The advantages of reducing the number of heat exchange services to one were discussed earlier. Additional cost reductions accrue because of the ability to package the plate fin exchangers and associated headers/piping into cold boxes.

Cold boxes are modular in nature. Multiple boxes can be fabricated and assembled in a controlled shop environment and transported to the site, ready for installation and hookup. This allows for reduced field construction hours, improved quality, and increased flexibility in scheduling mechanical construction activities.

Insulation of low-temperature equipment, including the cryogenic exchanger(s), is a large expense in an LNG plant. When cold-boxes are not used, insulation of equipment is among the last activities in the construction sequence. Field insulation is time-consuming and control of quality is difficult. Weather related factors such as rain and moisture can add to the complications.

With the PRICO™ process nearly all the low temperature equipment is enclosed in cold boxes. Typically these cold boxes use loose filled perlite for insulation, and expensive field installation of block insulation is avoided.

High-purity Refrigerants Not Required

Because the PRICO™ process uses only a mixture of refrigerants it is not necessary to manufacture or purchase high-purity refrigerant. Typically, refrigerant components can be extracted from the feed gas and separated into individual components within the facility. The fractionation system is uncomplicated since only rough-cut purity is needed for the individual components.

The process operates over a broad range of refrigerant compositions. This composition can be readily adjusted while the unit is in operation.

Conserves Refrigerants

With the PRICO™ design the entire refrigeration loop, including the heat exchangers, is designed to withstand the settle-out pressure of the system. Even when the system warms up to ambient temperature, such as might occur during prolonged shutdowns, there is no need to vent the refrigerants. This flexibility not only conserves valuable hydrocarbon components but also makes restart of the unit fast and efficient.

HOW MUCH SAVINGS TO EXPECT

In a base load LNG plant, savings from use of the PRICO™ process result from lower equipment cost, reduced bulk materials, fewer construction hours and less engineering effort.

Since all processes require nearly the same compression power, the savings in equipment cost are attributed mainly to the reduction in the number of equipment services and to the use of plate-fin heat exchangers. Fewer stainless steel equipment and the reduction in the number of suction drums are other factors that reduce equipment cost. Our evaluations indicate a saving of over 20 percent in equipment costs for the liquefaction unit and associated fractionation section.

The main savings with the PRICO™ process arise from reduction in bulk material costs and consequently the substantial reduction in construction hours. Use of cold-boxes and the need for less field insulation are other significant factors. Based on these considerations the PRICO™ process can be expected to save 20 to 30 percent in bulk material and construction cost for the liquefaction unit.

When all the above factors, including the reduced engineering effort due to the simplicity of the process, are considered we project a saving of about 25 percent on the installed cost of the liquefaction unit.

CONCLUSIONS

The PRICO™ process offers a proven, cost-effective route to liquefying natural gas. The process has been successfully proven in both base load and peakshaving applications. Recent modifications to the process have improved its energy efficiency to a level where it is equivalent to competing processes. The main feature of the PRICO™ process is its simplicity. This translates into fewer pieces of equipment, less bulk materials and easier construction. Use of the PRICO™ process in base load LNG plants is expected to reduce the installed cost of the liquefaction unit by about 25 percent.

Figure 1

PRICO® LNG Process

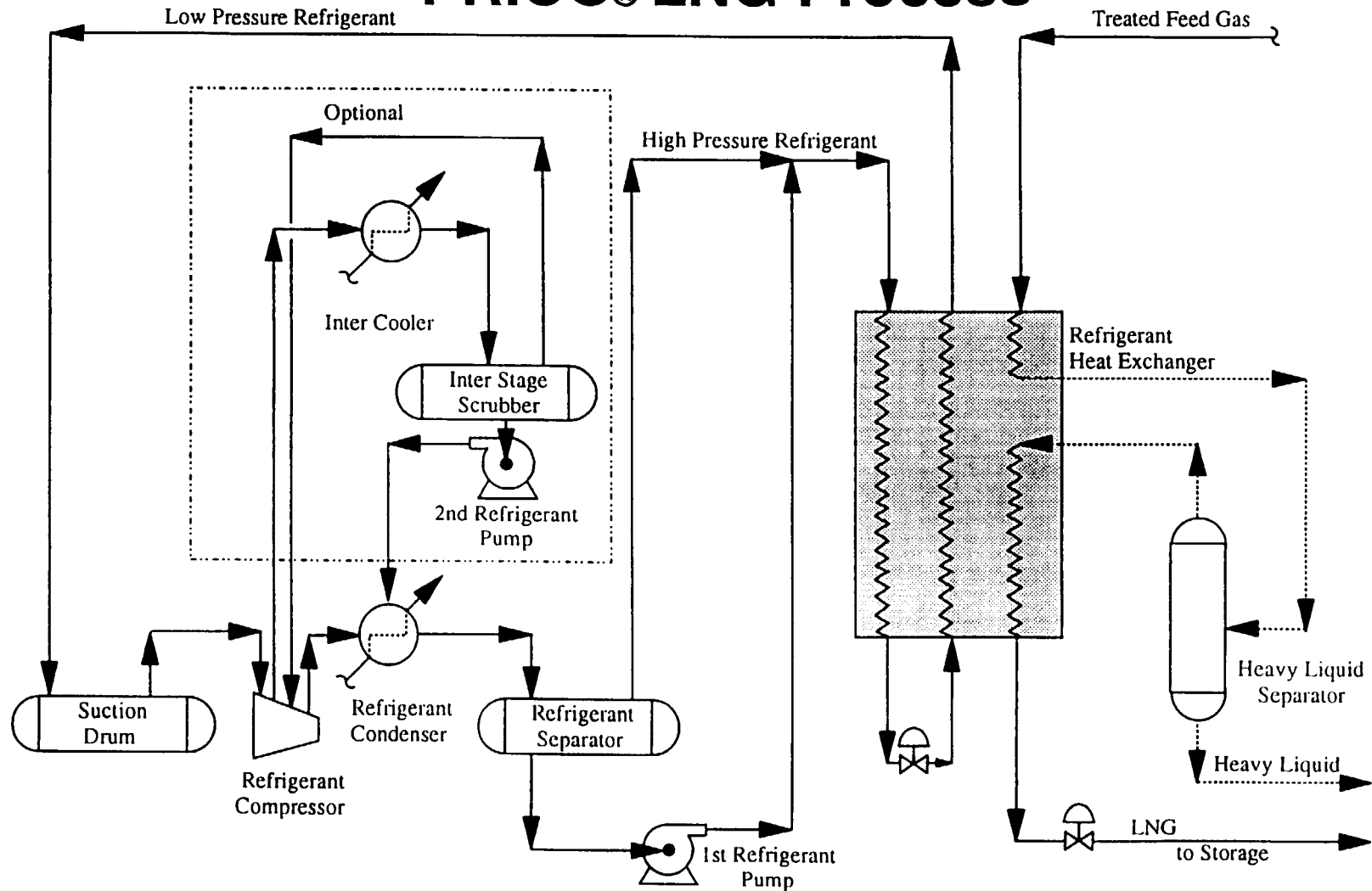
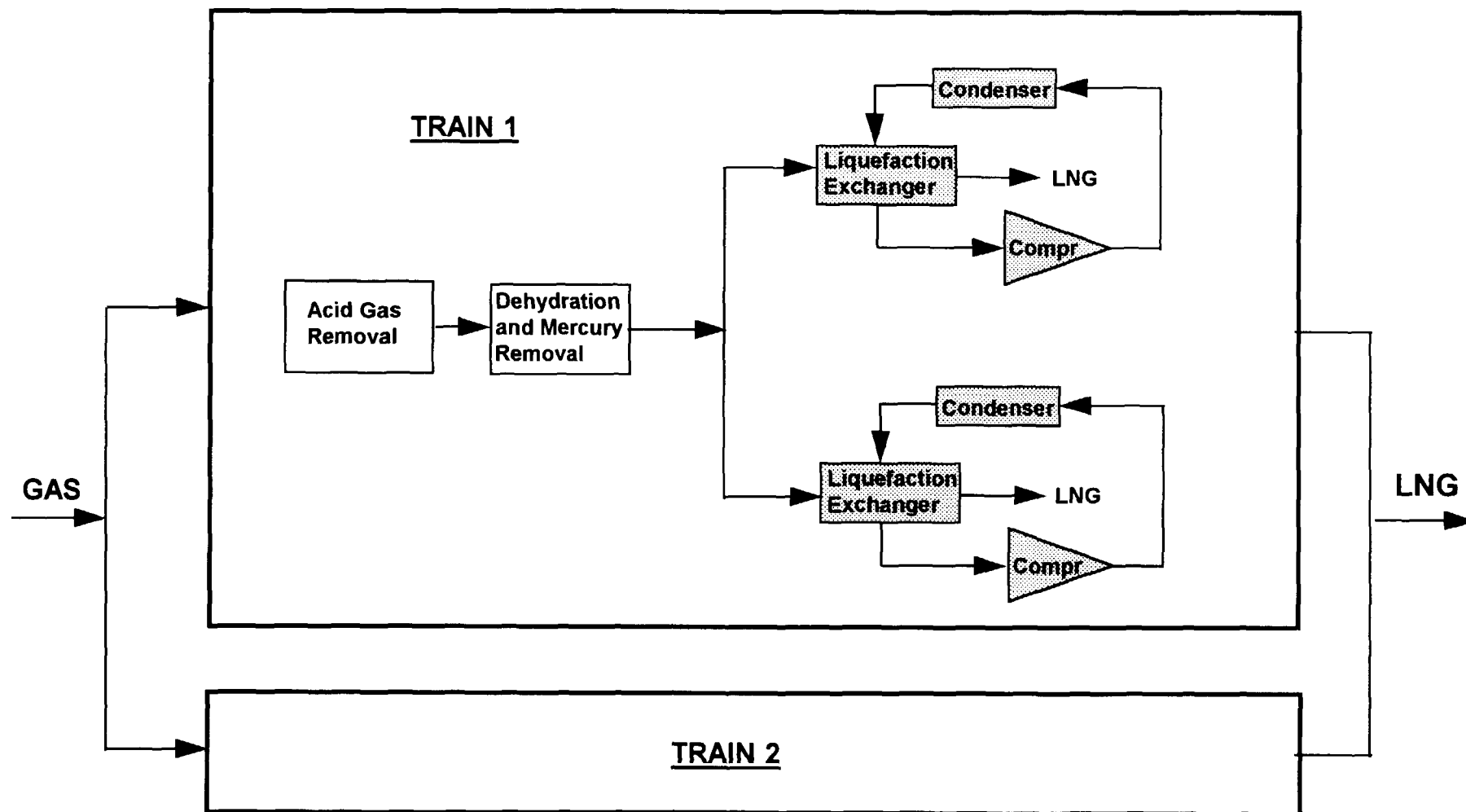


Figure 2

PARALLEL LIQUEFACTION LOOPS WITHIN LARGE TRAINS





“Middle East Gas : Prospects & Challenges”

Session (8)

The LNG Chain : Technological Innovations and Cost Reduction

Paper No. (8-3)

Conversion of Natural Gas into Liquid Fuels

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Conversion of natural gas to liquid fuels

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Abstract

Sasol has developed and commercialised its Slurry Phase Distillate (SPD) Process for the conversion of natural gas to liquid transportation fuels. This process is fully proven and offers a cost effective option for the utilisation of the abundant natural gas resources in the Middle East.

The process contains three steps with the first and third steps (synthesis gas generation and product work-up) consisting of processes which are available from a number of licensors. The heart of the process, Sasol's Slurry Phase Reactor for the Fischer-Tropsch synthesis step, has been developed and commercialised by Sasol.

The diesel produced from the process is of a very high quality from an environmental viewpoint, and the naphtha makes a good naphtha cracker feedstock.

Economic returns of an SPD plant are comparable with those of an LNG plant. However, the advantages that an SPD plant has over an LNG plant include a lower capital cost, and easier product marketing and distribution channels.

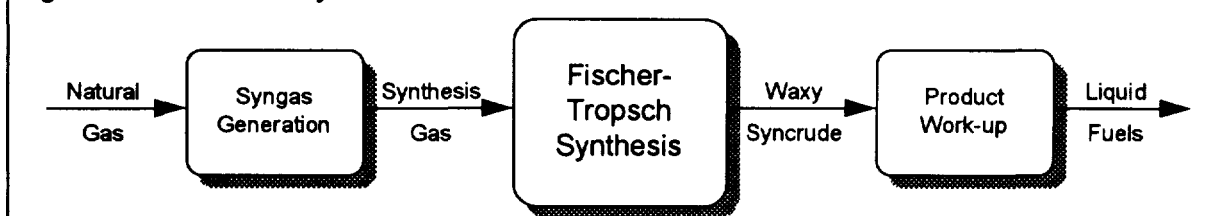
Introduction

In previous papers you have learnt about the abundance of natural gas in Qatar and the limitations, challenges and triumphs of gas utilisation, in particular the production of LNG. Sasol's commercially proven process for the conversion of natural gas to liquid fuels provides a cost effective option for the utilisation of this abundant natural gas.

Sasol's Slurry Phase Distillate Process

Sasol's process for the conversion of natural gas to liquid fuels - the Slurry Phase Distillate (SPD) Process - is a three step process (I), with each of the three steps being commercially proven processes. A single train of the SPD process will produce around 10 000 bbl/day of liquid transportation fuels from about 100 mmscfd of natural gas.

Figure 1: Sasol's Slurry Phase Distillate Process



1. Syngas Production

Synthesis gas (syngas) consists primarily of a mixture of hydrogen and carbon monoxide. For Sasol's SPD process, the main requirement from this step is that the synthesis gas has a hydrogen to carbon monoxide ratio of around two.

The conversion of natural gas to synthesis gas has been carried out for many years, for example as the first step in the production of methanol. There are a number of different methods for the production of synthesis gas such as steam reforming, autothermal reforming and partial oxidation. The method chosen would depend on project specific conditions. There are several licensors from whom this proven technology is available.

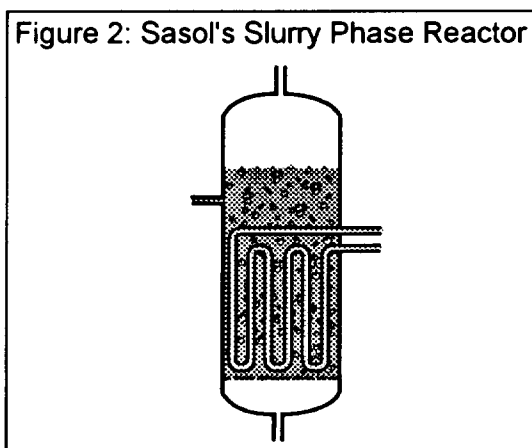
2. Fischer-Tropsch Synthesis

This is the heart of Sasol's Slurry Phase Distillate Process. Here the synthesis gas produced in the first step is converted into a waxy synthetic crude oil. This occurs in Sasol's technologically advanced, commercially proven Slurry Phase Reactor (II).

The reactor contains a mixture of liquid wax product with catalyst particles suspended in it. The syngas enters at the bottom of the reactor and bubbles through the wax. As it does, it reacts on the catalyst to form more wax and some vapour phase products. Product wax is removed from the reactor and vapour products leave at the top of the reactor together with some unreacted syngas. The lighter products are separated from the vapour phase by condensing and the unreacted syngas may be recycled if necessary. The heat of reaction is removed by the production of steam in the cooling coils inside the reactor.

The products from this second step are mixed to form the waxy synthetic crude.

Figure 2: Sasol's Slurry Phase Reactor



2.1 Sasol's Slurry Phase Reactor Development Path

Sasol has been operating conventional tubular fixed bed Fischer-Tropsch reactors (Arge Reactors) since 1955 when the original Sasol plant was commissioned. Since then, Sasol has continued to develop and optimise these conventional reactors. During this time it became apparent that considerable savings on capital and operating costs were possible, and that operations could be simplified by employing a slurry phase reactor instead of a tubular fixed bed reactor. Sasol's Research and Development group then embarked on an extensive program to develop a slurry phase Fischer-Tropsch reactor.

The investigations towards Sasol's Slurry Phase Reactor started in Sasol's laboratories on a microscale and progressed to a 2" diameter pilot plant. The next step was to carry out investigations in a demonstration unit in order to investigate the hydrodynamics, heat transfer and product separation. This demonstration unit is a 1m diameter unit with a capacity of about 75 bbl/day and was commissioned in 1990. This was followed by the commercial Slurry Phase Reactor which was commissioned in May 1993 and has a capacity of 2500 bbl/day. This reactor achieved an availability of 98% in its first year of operation. It is currently still in use at Sasol's facilities in South Africa for the production of Fischer-Tropsch waxes. Sasol's R&D group are continually utilising their expertise and experience in Fischer-Tropsch processes to optimise the reactor design and performance.

This extensive development and commercialisation programme has resulted in the Slurry Phase Reactor technology being fully proven.

3. Product Work-up

The waxy synthetic crude from the second step are worked up in the third and final step to yield final quality products. The waxy hydrocarbons are easily cracked and isomerised, under mild conditions, to produce naphtha, kerosene and diesel. The ratio of naphtha to distillates is roughly 20:80 and may be altered slightly, if desired, by adjusting operating parameters.

The hydrocracking required in this step is the same as, if not simpler than, conventional refinery hydrocracking. Hydrocracking technologies are widely available from various licensors, thus this third step is also commercially proven.

With all three steps in the process proven, Sasol's Slurry Phase Distillate Process carries no more risk than any other commercial refinery or petrochemical process.

High Quality Eco-diesel is Produced

The products of Sasol's Slurry Phase Distillate Process are high quality liquid transportation fuels. These fuels are superior from an environmental viewpoint due to the absence of sulphur, the very low aromatics content and the very high cetane number.

The naphtha provides an ideal feed for a naphtha cracker.

The diesel has several of its characteristics far exceeding current specifications. The provisional specification for the diesel, compared to conventional diesel, is given in I.

Table 1: Fischer-Tropsch Diesel Properties

Property	Fischer-Tropsch Diesel	Conventional Diesel
Cetane number	>70	45 min
Aromatics (% volume)	<1	10-25
Sulphur (parts per million)	<1	500-2000
Density (kg/m ³)	780	800

Due to the very low sulphur and aromatics content and the very high cetane number, this diesel is best suited as a blending component for conventional diesels.

An alternative use for the Fischer-Tropsch waxy synthetic crude is, before hydrocracking, to blend it with a conventional crude oil if the Slurry Phase Distillate plant is located close to a refinery.

Economics

One module of Sasol's Slurry Phase Distillate Process produces 10 000 bbl/day of liquid fuels from a natural gas feed rate of 100 mmscfd. Such a module has a capital cost of US\$ 300 million on a US Gulf Coast basis which is equivalent to \$30 000 per daily barrel of installed capacity. This cost includes utilities and offsites and may vary slightly according to local conditions.

The first two steps in the process are close to their maximum single train capacities at 10 000 bbl/day, but the third step, product work-up, may have a much larger single module scale. Hence if more than one module of Sasol's SPD process were to be built in parallel, then there would be a cost saving in this third stage, as well as in the utilities and offsites areas.

The operating cost of the plant is of the order of \$5/bbl. This a direct operating cost only and excludes the gas feed and financing charges, but includes labour, catalyst, chemicals, etc. and, once again, may vary according to local conditions.

With a natural gas cost of around \$0.50/MMBTU, a return on investment of about 12-15% is realised for a single train process. This is similar to what can be expected from an investment in an LNG plant. The economic advantage that Sasol's SPD Process has over an LNG plant is that a much lower capital outlay is required. Other advantages are that the products - liquid fuels - have a much more flexible market, and that the products may be transported by conventional means, without the need of specialised vessels.

Conclusion

Sasol's Slurry Phase Distillate Process offers a commercially viable option for the utilisation of the abundant natural gas found in the Middle East. This process is commercially proven and its high quality products are easily marketed and transported.



“Middle East Gas : Prospects & Challenges”

Session (8)

The LNG Chain : Technological Innovations and Cost Reduction

Paper No. (8-4)

Reducing LNG Transportation Costs : Prospects and Challenges

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**SECOND DOHA CONFERENCE
ON NATURAL GAS**
March 17 - 19 , 1997
DOHA - QATAR



مؤتمر الدوحة الثاني للغاز الطبيعي
١٧ - ١٩ مارس ١٩٩٧
الدوحة - قطر

“Middle East Gas : Prospects & Challenges”

Session (9)

Safety & Environmental Considerations in LNG

Operations and Transportation

CHAIRMAN

Dr. Mohammed Al-Sada

Manager, Safety, Quality & Environment

Qatar General Petroleum Corporation

QATAR



“Middle East Gas : Prospects & Challenges”

Session (9)

Safety & Environmental Considerations in LNG Operations and Transportation

Paper No. (9-1)

Safety Aspects of the LNG Transportation Link

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Safety Aspects of the LNG Transportation Link

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Summary

This paper addresses the safety aspects of the LNG transportation links and the risk reduction methods which are currently used for ships, terminals and jetties. It deals with the design, construction, operation and crewing of LNG ships and the location, design and general operation of terminals and jetties. The main emphasis is on maritime matters. Particular attention is directed to the potential hazard of large releases of LNG such as through a damaged loading arm or a ship's ruptured cargo containment system, and these aspects are viewed from the perspective of safety in terminal design.

The design, construction and operation of ships, as opposed to terminals, are controlled via a very comprehensive list of international rules and regulations. These rules also specify detailed means of controlling their application.

In view of the non-availability of international rules for terminals and jetties, this paper recommends that, during site selection, the level of all maritime risks should be quantified and focuses on methods of risk reduction during cargo operation alongside and during harbour manoeuvring.

As described in risk assessment theory, operational solutions are found by acceptance or non-acceptance of some category of risks.

The question being addressed in the paper is how best to minimise large risks, even though remote, by design factors at the start of a project.

Safety Aspects of the LNG Transportation Link

Introduction

An LNG scheme is composed of four parts, each having equal importance in the performance of a project; the gas production well, the liquefaction plant, the storage and transportation facilities and the vaporisation/distribution plant. The storage and transportation facilities are the part most exposed to public scrutiny. These can also be prone to accidents. Interruption in the transportation link for any substantial length of time due to an accident can put a severe economic burden on the project and damage its public image.

This paper addresses the safety aspects of the LNG transportation links and the risk reduction methods which are currently used for ships, terminals and jetties. It deals with the design, construction, operation and crewing of LNG ships and the location, design and general operation of terminals and jetties. The main emphasis is on maritime matters. Particular attention is directed to the potential hazard of large releases of LNG such as through a damaged loading arm or a ship's ruptured cargo containment system, and these aspects are viewed from the perspective of safety in terminal design.

The design, construction and operation of ships, as opposed to terminals, are controlled via a very comprehensive list of international rules and regulations. These rules also specify detailed means of controlling their application.

As can be seen from much of its earlier work, SIGTTO urges acceptance of a wide range of equipment and procedures for the reduction of operational risks. In view of the non-availability of international rules for terminals and jetties, this paper recommends that, during site selection, the level of all maritime risks should be quantified and focuses on methods of risk reduction during cargo operation alongside and during harbour manoeuvring.

As defined in reference (1), risk consists of a combination of event frequency and consequence. Thus, when assessing risks against this definition, designers are often faced with a number of choices when selecting a site. These may arise from a variety of competing pressures. As described in risk assessment theory, operational solutions are found by acceptance or non-acceptance of some category of risks. However, in the final analysis, whatever remote frequencies may be tolerated for a small gas release, in the case of a large release, the frequency should be reduced to non-credible proportions.

In essence, therefore, the question being addressed is how best to minimise large risks, even though remote, by design factors at the start of a project and, as will be expanded on later, the issue is made up of three components.

- Human elements and other weaknesses in operational procedures
- Questions of jetty position and design
- Methods of limiting the scale of an accident

High hazards must be identified during design and attention applied to restrict their effect.

The Ship

Design and Construction

Ship design and construction are controlled by a set of comprehensive and International Rules which are universally accepted. This is even more true for very specialised ships such as LNG tankers.

These rules are mainly laid down by the International Maritime Organization (IMO). The most important are incorporated in the International Convention for the Safety of Life at Sea (SOLAS), (2),(3),(4),(5),(6), covering the following subjects:

Chapter 1	General provisions
Chapter 2.1	Design and Construction - Hull, machinery and electrical installations
Chapter 2.2	Design and Construction - Fire protection, fire detection and fire extinction
Chapter 3	Life saving appliances and arrangements
Chapter 4	Radiocommunications
Chapter 7	Carriage of dangerous goods - Construction and equipment of ships carrying dangerous liquid chemicals in bulk and Construction and equipment of ships carrying liquefied gases in bulk.

Rule application is controlled and supervised by the Flag State of the ship. A ship's conformity with the rules is confirmed by the delivery of the following certificates:

1. Load Line Certificate
2. Safety Construction Certificate
3. Safety Equipment Certificate
4. Safety Radio Equipment Certificate
5. Certificate of Fitness for the carriage of liquefied gases in bulk (or dangerous liquid chemicals in bulk)
6. MARPOL Certificate

Some Flag States carry out their own inspections and administer their own certification process. However, most Flag States delegate these tasks to Classification Societies which are then empowered to deliver the certificates in the name of the Flag States.

Classification Societies have included all the SOLAS regulations into their own classification rules. They clarify and complement these rules with their own additions. These are mainly detailed considerations on construction materials, strength and buoyancy calculations, types of equipment, etc. for each particular type of ship.

To confirm the application of these detailed rules, Classification Societies deliver their own Classification Certificates for hull, machinery and cargo equipment.

All the certificates, issued by the Flag States or by Classification Societies, must be kept valid throughout the active life of the ship by means of periodic inspections. The interval between inspections varies from one year, for the simple ones, up to five years for the more comprehensive checks. The five year surveys, called Special Surveys, include complete

reinspection of most parts of the ships with detailed checking of the thickness of the hull, internal condition of the tanks and demonstration of the good operation of all machinery, electrical, cargo and radio and navigation equipment.

Operation and Crewing

Ship operation and crewing are also guided by comprehensive sets of International and National Rules.

The new International Safety Management (ISM) Code (7), also soon to be part of SOLAS, which will come into force in 1998, gives guidance for establishing methods for the organisation, administration and operation of ship operating companies. These rules are applicable to shore operating offices as well as to ships at sea. After establishing procedures and operating manuals as required by the code, operating companies and ships must be audited at regular intervals for confirmation that the rules are known and applied by all members of the company. The Code includes crewing procedures, hiring practices, conditions on board, levels of responsibility, health and safety, etc. which should also be clearly specified in the company instructions and enforced. Other items covered are maintenance, purchasing, protection of the environment, communication between shore and ship, correction of deficiencies, master's responsibility in case of emergency, etc.

The International Convention on Standards of Training, Certification and Watchkeeping for Seafarers, 1978, as amended by the 1995 STCW Convention (8), specifies the level of education, experience and training required from officers and ratings on board. It lays down the number of officers and their minimum qualifications. The ship's total complement is usually specified by National Regulations. The STCW Convention also discusses proficiency in a common language, maximum hours of work and minimum resting time, alcohol and drug policy, general health policy, etc. All these rules should be incorporated in the ISM procedures mentioned previously.

Chapter 5 of SOLAS controls safety at sea and navigation. Chapter 7 deals with cargo and safety operation on gas and chemical tankers through the IGC and BCH Codes.

MARPOL Annexe 1 covers oil pollution from ships which can have implications for ship-bunkering operations.

Summary

Ship design, construction, crewing and operation are well covered by very comprehensive sets of rules, all agreed on an international basis. Through regular inspections, it must be ensured that these rules are in force, known and followed by all people involved in the ship's operation, including the crew on board, and that all required inspections and certificates are up to date. This should give reliable confirmation that the ship is in good order and properly operated and maintained.

Gas carriers, particularly LNG tankers, have maintained, from the beginning of the trade, a very good operational and safety record. Most organisations involved in ship inspections confirm that gas tankers are, in general, the ships showing the least amount of deficiencies and those having the best trained crews. This is probably due, in part, to the high values of the

ships and the cargoes transported and to the possibility of costly penalties in case of failure. This shows that today's risk reduction methods are reasonably effective. However, it is important that this situation be maintained and even improved and that all new owners and operators of liquefied gas ships maintain a high standard of operation.

The Terminal

The situation for terminals is quite different. There are no international rules applicable to the construction, equipment or operation of liquefied gas terminals. A certain number of publications from international organisations such as OCIMF, IAPH, PIANC, BSI give advice on operational safety and design practices. In certain countries national rules have to be followed, such as those published by NFPA in the United States, the Health and Safety Executive in the UK, the Japanese Safety Bureau in Japan, CEN Standards and Standard Directives in Europe, and others. However, many countries have no rules of their own and rely either on rules from other countries or on the contractors in charge of the design and construction of the terminal to follow sensible international recommendations.

This makes for situations which are much more difficult to control and where individual choices might not necessary lead to the selection of the most efficient and safe option.

Site Selection

At its most elementary level, site selection for liquefied gas loading terminals is determined by the location of production wells and, at receiving terminals, the situation is dependant upon the location of markets. Thereafter, fine tuning is influenced by incremental costs such as linking into gas transmission systems and accessing distribution networks. However, there are other important considerations such as easy access from the sea and safe distance from other inhabited or industrial areas. A compromise must be reached which will limit marine and other risks and at the same time allow the position of the jetty and the terminal to remain within realistic limits.

The main concerns regarding marine risks are as follows:

- Depth of sheltered water
- Easy access from sea
- Immediate adjacency to LNG terminal
- Good moorings
- Protection from flow of other shipping traffic

Many references - such as reference (9),(10) and (11) - direct port designers to suitable areas for the construction of jetties.

Another matter to be addressed is the risk of ignition. In the event of an LNG spill, the spread of the gas cloud should be calculated with reference to the predominant wind, climatic conditions and local topography, such as harbour structures and the presence of the LNG ship itself.

An analysis of the dispersion characteristics of a gas cloud resulting from a range of spills under a variety of conditions can determine the extent of the gas cloud. The cloud range itself will be principally dependant on the spill rate and duration (12).

This is an important factor to take into account when determining the position of the terminal and jetty in relation to other facilities in the vicinity. *

General Design

In view of the lack of international standards covering the design and construction of terminals and jetties, if no national regulations are available, the designer has to rely on publications from the international organisations previously listed. However, most of these documents are of a somewhat general nature. They seldom quantify risks nor do they refer to specific ship-types. But when taken together, these sources can provide a robust framework around which LNG jetty designs can be initiated.

It can be seen, therefore, that basic guidelines are already available for securing a safe berth. However, it is a solution in which there may remain a remote probability for an accident to happen. Thus, when considering the distant possibility of major accidents, existing standards, though relevant, are seldom sufficient to obtain the assurance required for LNG. Accordingly, at LNG jetties, in addition to the guidelines mentioned above, risk related methods should be adopted which address event probabilities (1).

Solutions found by these methods can be more demanding than the basic criteria alone may suggest. They can also extend into areas where industry guidance is not yet fully established. However, a new series of standards from CEN, entitled *Installations and Equipment for Liquefied Natural Gas*, help to fill the gap and will soon be appropriate to European usage - perhaps even further afield. Furthermore, publications from SIGTTO such as (13) and (14) are also of help.

The type and quantity of equipment to be installed should be carefully considered in the context of risk reduction. Particular attention should be paid to the following items:

- Adequate size of access channels and turning circles
- Suitable fendering of the berth
- Indication of ship speed of approach
- Mooring equipment selected after detailed calculations of each specific mooring cases. Line tension monitoring and quick release hooks to be used.
- Loading arms equipped with double valves dry-break couplings, PERCs and QCDC connections.
- Double level ESD system with fibreoptic transmission accommodating also telephone lines and mooring lines tension monitoring channels.
- Fire protection equipment appropriate to the type and volume of cargo to be transferred.

General Navigational Risks

For any ship, the frequency of nautical accidents is greater in port than at sea. For the whole class of gas carriers (LNG and LPG), such accidents account for more than fifty per cent of the total reported and, when time factors are taken into account, this confirms the above statement.

Although good shipboard maintenance and quality training for ship and shore staff are essential, establishing safe conditions for the port transit of LNG carriers, whether by day or night, is always a matter of importance and is usually the responsibility of the port authority. In this respect, some recommendations are covered by IALA and include standards for harbour channel widths and turning circle diameters. In reference (15) - IMO also give recommendations pertaining to the control of ships during port transit.

VTs (Vessel Traffic System) controls are of particular relevance in this context. In areas of high traffic density, the shore-based VTS can be supplemented by an escort craft; in other situations the VTS may suspend other traffic movement in the channel during the LNG carrier's approach. Whatever arrangements are made, they should aim to limit close encounters with other ships.

A high standard of pilotage service is fundamental to minimising the risk of grounding or collision. As part of port design, it is vital to secure not only consistent high quality in harbour pilotage operations but also to fix pilot boarding areas at a suitable distance offshore. In addition, pilotage controls will include suitable light beacons etc. where and when night movements are planned.

In assessing port risks, the following matters should be taken into account:

- Number and type of ships and other craft using the port
- Port accident records
- The maximum draft of the vessels
- The nature of the sea bed

After studying such factors, port designers can introduce LNG-related provisions and under-keel clearances appropriate to the local environment, which should include:

- Effective VTS controls and the use of escort craft
- High standard of pilotage extended to an appropriate distance offshore.
- Adequate tug power to control LNG carriers, even in *dead-ship* condition
- Strict operating conditions

On a port by port basis, it should be noted that as part of terminal design, operating criteria, expressed in terms of wind speed, wave height and current should be established. The same weather parameters should be used to calculate the maximum wind forces acting on the largest LNG carrier using the port and, thence, the number and power of the tugs needed for berthing manoeuvres can be established.

Grounding and Collision Risks

Although containment rupture has never happened over the three decades of LNG carriage, an important risk to include in port analysis is the possibility of cargo release during grounding or collision. To limit the risk, each port should be investigated for the presence of dangers which could cause critical impact. Port designers, when assessing individual hazards, should use these investigations and consider human fallibility. This should be done to ensure a satisfactory safety margin and it is an insurance against cargo containment system rupture. Accordingly, when applying this method, the following safeguards are assumed to fail:

- Operational procedures
- Back-up warnings, and
- Human controls

Obviously, such high risk events are extremely rare in LNG shipping. Nevertheless, it is only after the above site-specific investigation has been completed that assurance of protection of the ship's cargo containment system is provided. Because of the unquantifiable nature of the human element, it is only by removal of the possibilities for containment system penetration that the correct level of port security can be obtained.

When considering collisions or groundings for most LNG carrier hull designs, methods are available to estimate the damage which may result in a large release of LNG. This is achieved by identification of the energy necessary to penetrate the ship's double hull. Due to the double hull configuration, the risk of a gas release is much limited, therefore unrealistic port restrictions do not come into play. It is possible to identify accident scenarios with potential for such damage and to remove the risks. This means it is possible to set criteria for accident severity (in terms of ship speed) below which rupture of the cargo containment system is virtually impossible.

Port, Terminal and jetty operation

One of the great advantages of LNG projects is their long term preparation and even longer term duration. This allows for very careful exchange of information between the terminal and the ship manager long before the start of the project. All aspects of the ship-shore interface are reviewed in order to ensure their compatibility. Detailed exchange of information should be maintained for the duration of the project (16). The early information exchange should include:

- Size of berth in relation to size of ship
- Mooring plan and mooring calculations based on predominant weather conditions
- Cargo connections
- Ship-to-shore communication systems and procedures including ESDS
- Ship-to-shore access
- Review of respective operation procedures including limiting operating conditions
- Use of International Ship-Shore Safety Check List for Gas Carriers (17)
- Procedures for the loading of stores and utilities
- Emergency procedures; respective actions in case of emergency (18) and (19)
- Information on deficiencies and work to be carried out during the transfer period.

Human Element

It must be noted that accident reports show risk management is often frustrated by an inability to completely obviate human error. Indeed, the large majority of casualties continue to be attributed to this factor.

Training of ship and shore staff is obviously extremely important. The level of training for ship staff is well defined by the rules described in the first part of this paper. However for terminal and in particular jetty personnel there are no international set requirements. Reference (20) shows a training manual produced by SIGTTO to provide an equivalent level of training for jetty supervisors and jetty operators.

However, even a good level of training does not appear to be sufficient to guarantee fool-proof situation.

Accordingly, today's design techniques usually take human error into account, attempting to control it by means of fail-safe equipment and operational procedures. The positive contribution of these measures to risk reduction is clear. However, even for LNG, accident data shows that basic techniques involving human controls are less than one-hundred per cent effective. Thus, when limiting the chance of a significant accident - to match a very low risk exposure - today's range of industry standards are less than fool-proof.

It is therefore suggested, that, in seeking operational solutions for LNG, it is necessary to adopt design methods which, as far as possible, discount the contribution of human judgement.

Conclusion

This paper is an attempt to describe the main risk reduction measures which are used to improve the safety of the transportation link of an LNG project. The aim is not to cover all the detailed measures available but only to shown the main aspects of the problem.

LNG's excellent safety record over three decades owes much to present-day standards. However, as the industry becomes more widespread, continued success depends on further improvements.

Although LNG has an enviable safety record, it is not risk free. Some hazards are difficult to eliminate and an accident, albeit rare and unlikely, is possible as a result of human error or catastrophic event such as very bad weather at sea or an earthquake on shore. A remote chance remains for some incident to occur and, because of weaknesses in human controls, such risks, especially those related to major releases, should be reduced to non-credible proportions by suitable design.

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- 1) *Guidelines for Hazard Analysis as an Aid to Management of Safe Operations* - 1992 SIGTTO, ISBN 1 85609 054 X
- 2) *The International Convention for the Safety of Life at Sea* - 1974 and its protocol of 1978 articles, annex and certificates incorporating all amendments up to and including the 1991 amendments. 1992 Consolidated editions with 1992 and 1994 amendments - IMO Ref. 110E, 174E & 190E
- 3) *International Code for the Construction and Equipment of Ships carrying Liquefied Gases in bulk* (IGC Code) 1993 - IMO Ref. 104E
- 4) *Code for the Construction and Equipment of Ships carrying Liquefied Gases in bulk* (1983) - IMO Ref. 782E
- 5) *Code for Existing Ships carrying Liquefied Gases in bulk* (1976 edition) - IMO Ref. 791E
- 6) *International Convention for the prevention of Pollution from Ships* (MARPOL 73/38) including all amendments up to 1992 - IMO Ref. 520E & 544E
- 7) *International Safety Management Code* (ISM Code) 1994 edition - IMO Ref. 186E
- 8) *International Convention on Standard of Training, Certification and Watchkeeping for Seafarers* 1978 as amended by the 1995 Convention
- 9) *Site Selection and Design for Safety at LNG Ports and Jetties* - Information Paper No.14 SIGTTO, ISBN 185609 129 5
- 10) *Safety Requirements at LNG Terminals* - 1992 Gyles J.L., Shell International Maritime Ltd, LNG Conference Proceedings
- 11) *Criteria for Selection of Sites for LNG Terminals* - 1992 Gyles J.L., Shell International Maritime Ltd, SIGTTO Panel Paper
- 12) *Dangerous Goods in Ports: Recommendations for Port Designs and Port Operators* - 1985 (PIANC) Permanent International Association of Navigation Congresses
- 13) *Accident Prevention - the Use of Hoses and Hard Arms at Marine Terminals Handling Liquefied Gas* - Information Paper No.4 - 1996, SIGTTO, ISBN 1 85609 114 7
- 14) *A Guide to Contingency Planning for Marine Terminals Handling Liquefied Gases in Bulk*, 1989, SIGTTO/ICS/OCIMF, ISBN 0 948691 81 6.
- 15) *Recommendation on the Safe Transport Handling and Storage of Dangerous Substances in Port Areas* International Maritime Organization (1983). Revised 1995 - ISBN 92 801 1329 1

16) *The Ship/Shore Interface Communications - Necessary for matching ship to berth*
Information Paper No.5 - 1997, SIGTTO, ISBN 185609 128 7

17) *International Safety Check List for Gas Carriers.* This document can be found in the following 3 publications:-

ICS/OCIMF International Safety Guide for Oil Tankers & Terminals (Revised 1991)

ICS Tanker Safety Guide (Liquefied Gas) (Revised 1995)

SIGTTO Liquefied Gas Handling Principles on Ships and in Terminals (Revised 1995)

18) *Safe Haven for Disabled Gas Carriers. A Consultative Document in the Seeking and Granting of a Safe Haven.* (1982) SIGTTO

19) *A Guide to Contingency Planning for the Gas Carrier alongside and Within Port Limits,* 1987, SIGTTO/ICS/OCIMF, ISBN 0 9 948691 27 1

20) *Training of Terminal Staff Involved in Loading and Discharging Gas Carriers (1996)*
SIGTTO - ISBN 185609 092 2



“Middle East Gas : Prospects & Challenges”

Session (9)

Safety & Environmental Considerations in LNG

Operations and Transportation

Paper No. (9-2)

Halon 1301 Replacement in ADGAS Installations

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**ABU DHABI GAS LIQUEFACTION COMPANY LIMITED
(ADGAS)**

LNG Plant - Das Island

**HALON 1301 REPLACEMENT
IN
ADGAS INSTALLATIONS**

**Abdullah M. Obaid Al-Zaabi
Deputy Head of Safety & Loss Prevention**

EXECUTIVE SUMMARY

Halogenated hydrocarbons commonly known as Halons are excellent fire fighting agents. The production of Halon has ceased effective January 1st, 1994 in developed countries due to its Ozone Depletion Potential. In compliance with ADGAS policy of protecting the environment and due to non availability of virgin Halon, plans for replacement of Halon 1301 in existing installations based on qualitative fire risk analysis have been reviewed in this paper.

Halon replacements presently being marketed are not perfect replacements and simple drop-ins for Halon 1301. Their use requires extra quantity of the extinguishing media and a substantial change in the hardware. Some of these replacements have good potential but there is the possibility of their use being limited or even banned in future. The development of and the search for an ideal replacement of Halon 1301 still continues.

Other gaseous alternatives for Halon 1301 (e.g. CO₂, Argonite & Inergen), based on present knowledge, are suitable for normally unmanned areas. Non-gaseous alternatives (e.g. Water spray, Water mist & Hi-Ex foam) are not suitable for ADGAS installations where Halon is currently being used.

A qualitative fire risk assessment of Halon installation has confirmed that use of Halon in ADGAS installation cannot be classified as "essential use". The findings of the risk assessment can be summarised as follows:

- (i) Halon system is not required in manned control rooms and conventional detection system is considered adequate.
- (ii) Halon system in floor void should be replaced by a CO₂ system in conjunction with conventional detection system.

- (iii) Halon system is not required in switch gear rooms and incipient detection system is adequate.
- (iv) Conventional detectors should be replaced by incipient detection system in unmanned areas and where early detection of fire is critical.
- (v) Fire load should be reduced by improved housekeeping and removing combustible items from Halon protected area.

Until such time the above recommendations are implemented, the present systems shall be properly maintained and kept on manual mode to avoid spurious discharges. In case of fire, personnel on site should not manually actuate the fixed Halon system for fire fighting. Instead they should use portable extinguishers for initial attack and call Das Island Fire Service for assistance. Use of fixed Halon system for fire fighting should be left to the discretion of the Shift Superintendent and/or Superintendent Fire and Rescue Services (Das).

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11. Appendix - 2 Qualitative Fire Risk Assessment Criteria.	

1. INTRODUCTION

Due to its potential of depleting the ozone layer in the stratosphere, production of virgin Halon 1301 has ceased in developed countries with effect from January 1st, 1994. Due to non-availability of virgin Halon and to comply with ADGAS policy of protecting the environment, Safety and Loss Prevention Department (SLPD) reviewed the subject in February 1995 and issued a report titled "Updated report on strategy for Halon 1301 replacement in ADGAS installations".

In October 1995, a working committee comprising of members from ADNOC and its group companies was formed to harmonize a common philosophy on Halon removal. The working committee during one of its meetings on January 15, 1996 agreed that all group companies should undertake a Qualitative Risk Analysis of their installations protected by fixed Halon 1301 suppression system. The purpose of this analysis is:

- (i) To decide if use of Halon 1301 in any installation can be classified as "essential" as defined by Montreal Protocol.
- (ii) Determine the need for a fixed Halon 1301 system.
- (iii) Provide recommendations for improving the fire risks to an acceptable level if existing Halon system is removed.

This report is the result of the Qualitative Risk Analysis carried out by SLPD of all Halon 1301 installation in ADGAS and deals with their present status and future plans.

2. HALON INSTALLATIONS IN ADGAS

Currently there are sixteen fixed Halon 1301 installations located on the LNG facilities at Das Island as detailed below:

<u>LOCATION</u>	<u>QUANTITY (Kg)</u>
4 Control Rooms	4423
9 Outstations	1925
Power Station	404
3 Substations	1324
Total	<u>8076 Kg</u>

The quantity is inclusive of the reserve Halon on site. In addition to this, 958 kg Halon is being held as inventory in the stores.

3. ESSENTIAL USE CRITERIA

The term "essential" should be qualified in that it is not the Halon that is essential rather it is the criticality of a particular facility or equipment afforded protection by Halon, or the mitigation of a threat to life, that is of concern.

The use of Halon should qualify as "essential" only if :

- (i) It is necessary for the health, safety or is critical for the functioning of the society; and
- (ii) There are no available technically and economically feasible alternatives or substitutes that are acceptable from the standpoint of environment and health.

A review of Halon installations in ADGAS confirm that none of these fall under the category of "essential use" as per above criteria.

4. HALON REPLACEMENTS

Fire extinguishing agents which are chemically similar to Halocarbons are considered as Halon 1301 replacement and they should have:

- (i) Zero Ozone Depletion Potential (ODP),
- and (ii) Low Toxicity to Personnel.

Additionally, Global Warming Potential (GWP) and atmospheric life time should be considered as these might be subject to regulations in future. Essentially, the requirement for a Halon 1301 replacement can be summed up thus.

- (i) Effective fire control/extinguishment.
- (ii) Electrically non-conductive.
- (iii) Zero ODP.
- (iv) Acceptable toxicity level.
- (v) Clean application without residue.
- (vi) Direct refill capability without system change.

Total flooding agents presently being marketed as replacement for Halon 1301 are Triodide, FM-200, NAF S III, FE-13, FE 241, FE 25 and CEA 410& 614. The environmental properties of these Halon replacements are tabulated in Appendix-1. These products meet some of the above requirements but not one of them appears to meet all of the requirements. There is the possibility that their use will be limited or even banned in time, as their effect on the environment is better understood.

5. GASEOUS HALON ALTERNATIVES

Alternative gaseous fire extinguishing agents for total flooding systems are:

Carbon dioxide.

Argon - Nitrogen mixture (Argonite).

Argon - Nitrogen mixture with added CO₂ (Inergen).

Carbon dioxide is a well known fire extinguishing agent suitable only for unmanned areas due to asphyxiation hazard.

Argon / Nitrogen mixture (marketed under the trade name of Argonite) extinguishes fire when applied in concentration ranging from 34-50% by reducing the concentration of oxygen in the environment. Due to resulting low levels of oxygen they have the potential for asphyxiation and possible death.

Argon / Nitrogen mixture with added carbon dioxide (marketed under the trade name of Inergen) extinguishes the fire in the same way as Argonite. Addition of CO₂ stimulates respiration to compensate for lower oxygen level.

All the three gaseous alternatives for Halon 1301 are thus suitable only for normally unmanned areas.

6. NON GASEOUS HALON ALTERNATIVES

Water mist, high expansion foam and water spray systems can, in some cases, be used for fixed fire protection in installations where Halon 1301 has been used previously. The use of Halon 1301 in ADGAS installation is limited only to control rooms, outstations, electrical substations, computer rooms and battery rooms. These non-gaseous alternatives do not appear to be suitable for these installations.

7. STRATEGY FOR EXISTING HALON INSTALLATIONS

Until all proceedings are implemented the following shall be maintained.

- (i) Continue maintaining all Halon systems on manual mode of operation.
- (ii) Continue routine testing and maintenance of fire detection system.
- (iii) Continue inspection and maintenance of Halon systems to avoid leakage.
- (iv) Review and amend maintenance procedure to ensure that Halon is not inadvertently discharge during maintenance/testing.

- (v) In case of fire in any of these installations, personnel on site shall not manually discharge the Halon for extinguishing the fire. Instead they should attack the fire with appropriate portable fire extinguishers and call Das Island Fire Service (DIFS) for assistance as per existing procedure.
- (vi) Improve housekeeping in all installations where Halon 1301 is provided. Remove unwanted material & items made of combustible material.
- (vii) Appraise all concerned personnel of the impact of Halon discharge on our environment.
- (viii) Maintain existing Halon systems on manual mode of operation.
- (viii) Review maintenance procedures to ensure that all necessary measures are taken to prevent inadvertent Halon discharge.
- (x) Investigate all inadvertent Halon discharges to determine the basic causes and implement remedial action.

8. FIXED FIRE PROTECTION SYSTEM FOR ADGAS INSTALLATIONS

A decision to determine the need for a fixed fire suppression system for a new or existing installation should be based on a Qualitative Fire Risk Assessment as per the criteria given in Appendix - 2.

A review of all ADGAS Halon installations based on the above referred criteria was done to determine whether a fixed fire protection system is needed, and if not, what should be done to improve the detection system to maintain the risks at an acceptable level.

Based on the criteria given in Appendix - 2. The following have been decided for ADGAS Installations.

- (1) Control rooms that are staffed on a continuous basis do not need an automatic fire extinguishing system. Conventional smoke detectors with alarm is considered sufficient and it has been recommended to delete Halon 1301 system from all control rooms.
- (2) Due to restricted access for manual intervention in case of fire in a floor void area, a fixed fire suppression system is needed under raised floors. A fixed CO₂ system has been recommended with necessary features for personnel protection e.g. pre-discharge alarm, manual override, abort switch and means of locking the system. Existing Halon 1301 system shall be removed from the floor voids.

- (3) A fixed fire suppression system is not required in switch gear rooms provided:

- rooms have electrical equipment within
- do not represent a risk to life safety
- covered by an effective detection system
- portable wheeled CO₂ extinguisher is available
- current is isolated in the event of short-circuit or overload

Based on these criteria it has been recommended to delete existing Halon 1301 system and replace conventional detectors with incipient fire detection system in all substations except L1/L2. A fixed CO₂ system has been recommended for L1/L2 due to presence of large number of oil filled circuit breakers and the concern regarding its criticality expressed in RADO report.

- (4) Fire load of all areas from where Halon 1301 system is being deleted should be reduced by:

- improved housekeeping,
- reducing inventory of combustibles and removing unwanted material,
- storing drawing/documents in metal cabinets,
- replacing wooden battery racks with metallic racks,
- replacing wooden furniture with metal furniture.

- (5) Replace conventional detectors with incipient detection system where early detection is critical to reduce damage due to fire.
-

9. REFERENCES

- 1) NFPA 2001-1995 "Clean Agent Fire Extinguishing System".
- 2) BP Report No. BPE.92ER.047 "Alternatives to Halon 1211 and 1301".
- 3) E&P Forum Report No.6.39/214-Nov. 1994 "Guidance on Halon Free Fire Protection System".
- 4) Inherent fire safety design principles. E&P Forum Report No.6.48/231 - Dec 1995.
- 5) Report of the 7th meeting of the parties to the Montreal Protocol on substances that deplete the ozone layer (UNEP/OZL.Pro. 7/12. Dec 27, 1995) available on Internet at <http://acd.ucar.edu>.
- 6) Offshore Engineer - Nov. 1992 "Friendly Fire Spray".
- 7) Professional Safety - Nov. 1994 "Search for a Halon Replacement".
- 8) Resource Protection UK. Training course material titled " Gaseous Extinguishing Agents System Design & Testing".
- 9) Review of Halon systems - Review Team report and recommendation - ADCO.
- 10) Minutes of meeting of working group on "Management of Halon Removal and Replacement for ADNOC Group of Companies".
- 11) "Halon Alternatives - an up-to-the-minute profile" published in Industrial Fire Journal- Jan 1996.

ENVIRONMENTAL PROPERTIES
OF
HALON REPLACEMENTS

Agent	ODP ¹	GWP ²	Atm. Lifetime
Halon 1301	12-16	5800	100 years
Triiodide	0.0	<5	1 day
CEA 614	0.0	5200	3100 years
FE 241	0.022	440	7 years
FM-200	0.0	2050	31 years
FE 25	0.0	3400	41 years
NAFSH	0.044	1358	14 years
CEA 410	0.0	5500	2600 years
FE 13	0.0	9000	280 years

1. Ozone Depletion Potential Relative to CFC-11
2. Global Warming Potential.
Based on a 100 - year horizon, relative to CO₂

CRITERIA USED FOR
QUALITATIVE FIRE RISK ASSESSMENT

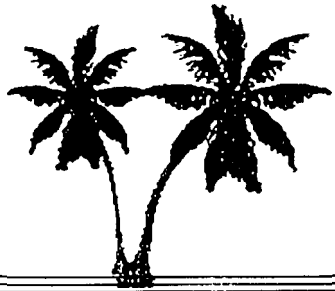
A group of subject headings are used as the basis for determining the need for a fixed fire suppression system. Emphasis is placed on requirements concerning evacuation, personnel safety and continuity of operations.

Each risk was analyzed for the following concerns:-

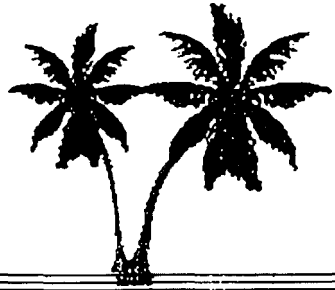
1. Plant/ Equipment Protected.
2. Function of protected area.
3. Personnel occupancy.
4. Fire load.
5. Fire risk.
6. Evacuation capability.
7. Access for manual firefighting.
8. Fire spread/ containment potential.
9. Standard of housekeeping.
10. Effect of fire on personnel in immediate vicinity.
11. Effect of fire on continuity of operations.

Based on above factors.

1. Is fixed protection system necessary?
2. If no fixed protection system is required, what additional precautions are necessary to maintain risks at an acceptable level.



**ADGAS OPERATES
THREE LNG TRAINS
AND PRODUCES
LNG + LPG
PENTANE - PLUS
LIQUID SULPHUR**

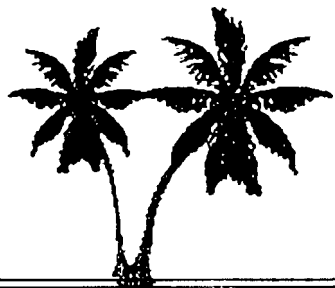


PHASE-OUT SCHEME



Minimize Fire Risk by:

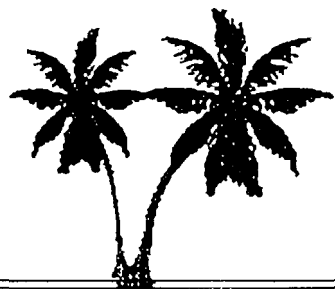
1. Improve housekeeping.
2. Reduce combustibles.
3. Use metal cabinets for documents.
4. Use metal battery racks.
5. Use metal furniture.



AIM



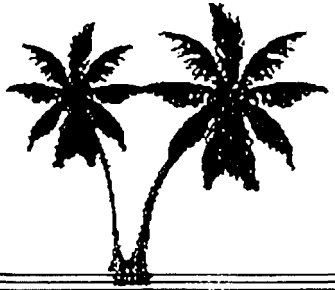
1. DEFINE ADGAS INSTALLATIONS PROTECTED BY HALON 1301.
2. DETERMINE THE ESSENTIAL USE OF HALON 1301 FOR THESE INSTALLATIONS.
3. DETERMINE THE NEED FOR HALON 1301.
4. DEFINE THE ALTERNATIVE FOR REPLACEMENT.
5. PROVIDE RECOMMENDATION TO IMPROVE FIRE RISK TO ACCEPTABLE LEVEL.



HALON INSTALLATION IN ADGAS



INSTALLATION	QUANTITY (KG)
4 Control Rooms	4423
9 Outstations	1925
1 Power Station	404
3 Substations	1324
Total	8076 (KG)

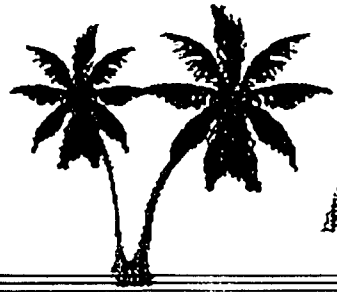


ESSENTIAL USE



**If necessary for health, safety or critical
for society function.**

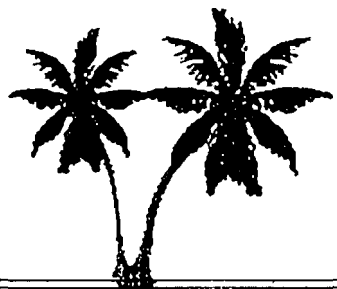
If alternative is not available.



REPLACEMENT ALTERNATIVES CRITERIA



1. Zero ozone depletion potential.
2. Low toxicity to personnel.
3. Zero/low global warming potential.
4. Effective fire extinguishment.
5. Electrically non-conductive.
6. Clean application, no residue.

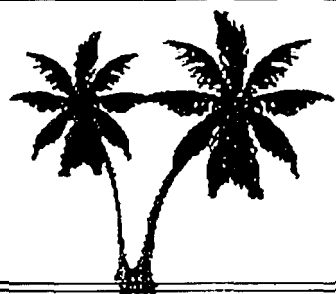


GASEOUS HALON ALTERNATIVES



- 1. Carbon dioxide.**
- 2. Argonite.**
- 3. Inergen.**

Suitable for unmanned area.

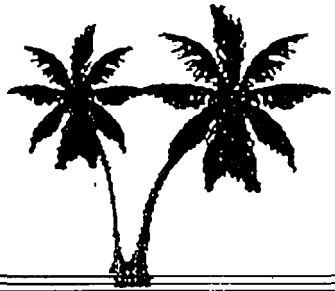


NON GASEOUS HALON ALTERNATIVES



- 1. Water mist.**
- 2. High expansion foam.**
- 3. Water spray system.**

Not suitable for ADGAS Installations.

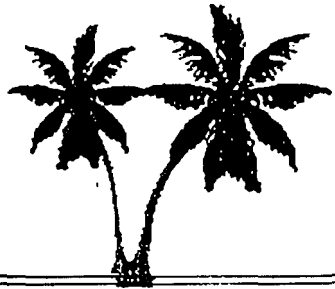


PHASE-OUT SCHEME



Substations

Remove Halon, replace conventional detectors with incipient except in L1 and L2.

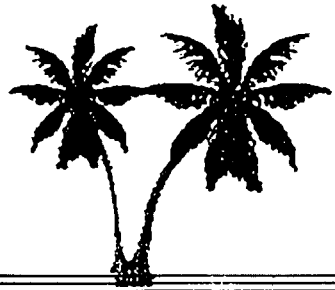


PHASE-OUT SCHEME



Substations

Remove Halon, replace conventional detectors with incipient except in L1 and L2.

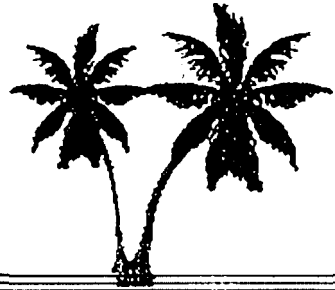


PHASE-OUT SCHEME



Control Rooms

1. For manned rooms use conventional smoke detectors only.
2. For floor voids use CO₂.

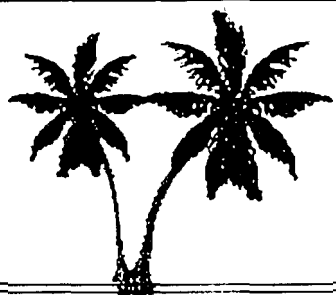


CRITERIA USED FOR QUALITATIVE FIRE RISK ASSESSMENT



(Cont'd)

- 8. Fire spread/ containment potential.**
- 9. Standard of housekeeping.**
- 10. Effect of fire on personnel in immediate vicinity.**
- 11. Effect of fire on continuity of operations.**

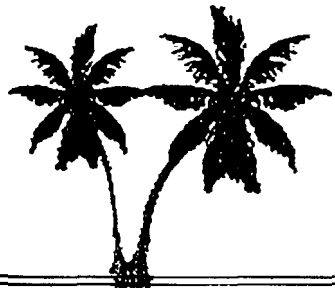


CRITERIA USED FOR QUALITATIVE FIRE RISK ASSESSMENT



Each risk was analyzed for the following concerns

- 1. Plant/ Equipment Protected.**
- 2. Function of protected area.**
- 3. Personnel occupancy.**
- 4. Fire load.**
- 5. Fire risk.**
- 6. Evacuation capability.**
- 7. Access for manual fire fighting.**

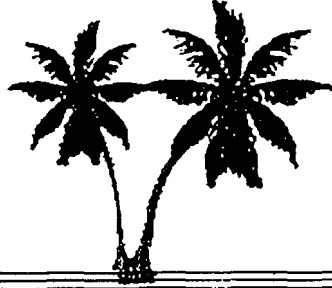


PHASE-OUT SCHEME



BASED ON

**Qualitative Fire Risk Assessment
Criteria Appendix - 2**

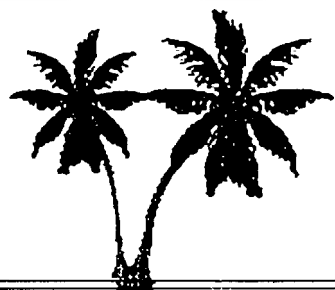


ENVIRONMENTAL PROPERTIES OF HALON REPLACEMENTS



Appendix - 1

Agent	GWP*	CMP	Atm. Lifetime
Halon 1301	12 - 16	5800	100 years
Triodide	0.0	< 5	1 day
CEA 614	0.0	5200	3100 years
FE 241	0.022	440	7 years
FM-200	0.0	2050	31 years
FE 25	0.0	3400	41 years
NAFSIII	0.044	1358	14 years
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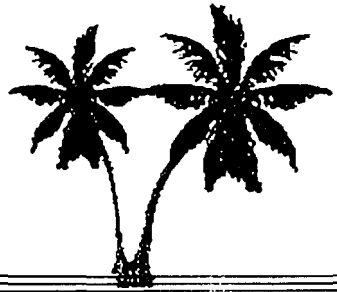


STRATEGY FOR EXISTING HALON SYSTEM



(Cont'd..)

- 5. Use portable extinguisher.**
- 6. Improve environmental awareness amongst employees.**
- 7. Improve housekeeping.**
- 8. Investigate all inadvertent Halon discharges.**



STRATEGY FOR EXISTING HALON SYSTEM



- 1. Keep on manual mode.**
- 2. Continue maintenance.**
- 3. Continue routine inspection.**
- 4. Review and amend maintenance procedure as required.**



“Middle East Gas : Prospects & Challenges”

Session (9)

Safety & Environmental Considerations in LNG

Operations and Transportation

Paper No. (9-3)

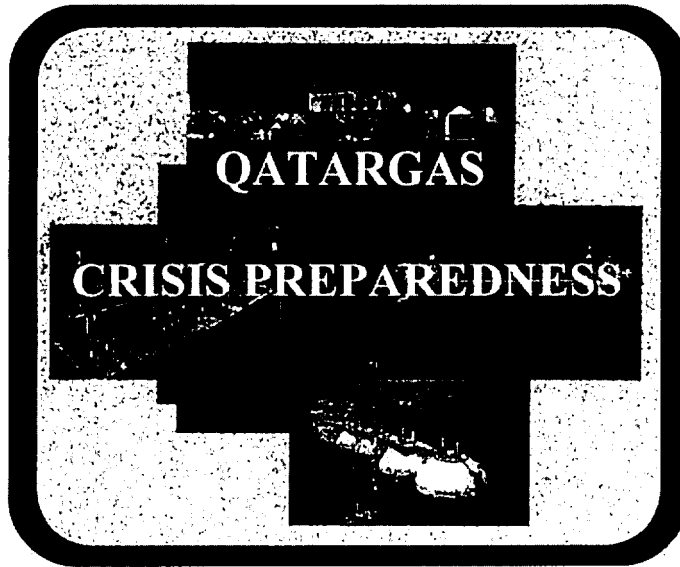
Qatargas Crisis Preparedness

Rick Mire

Safety & Environment Manager,

Qatar Liquefied Gas Company

QATAR





Crisis Preparedness



VALDEZ



BHOPAL



CHERNOBYL



Defining Moment

- * Magnitude of the Event - CRISIS
- * Real or Perceived Inability to Respond



Effective Crisis Response

- Risk Assessment and Prevention.
- Safe Operation.
- Involvement and Co-operation with Governments/Stakeholders.
- Preparation and Training.
- Drills and Exercises.



STAKEHOLDERS



HEADQUARTERS

STRATEGIC



TACTICAL

ONSCENE



INCIDENT

Media Public Shareholders
Government Customers
Employees



Exercise to Learn

- Validate Plans, Resources and Integrated Response Concepts.
- Test Communications.
- Mobilize Response Equipment & Personnel.
- Clarify Linkage with Government.
- Practice Media and Public Relations Interface.



Crisis Management Strategy

- Concern for People and Environment.
- Industry, Government and Stakeholders Working Together.
- Be Prepared. **Take Action.**
- Move Quickly From a Crisis to a Managed Project



Success Factors

- Teamwork.
- Working Response Plan.
- Training.
- Well Coordinated Execution.



“Middle East Gas : Prospects & Challenges”

Session (9)

Safety & Environmental Considerations in LNG Operations and Transportation

Paper No. (9-4)

Safety & Environmental Aspects in LNG Carrier Design

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Safety and Environmental Aspects in LNGC Design

by

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Abstract

“ Safety and Reliability“ has been and will continue to be a keyphrase in marine transportation of LNG.

MES (Mitsui Engineering & Shipbuilding Co., Ltd.) has utilized its all expertise and state-of- the-art technologies to realize this objective, resulting in exceptionally successful operations of LNGCs built by MES.

In line with the growing global concern about environmental issues, we need to pay more attention to the environmental aspects of the design and construction of LNG carriers.

Accordingly, in this paper, we present some topics related to safety and environmental concerns which need to be taken into consideration in LNGC design and construction.

1. Safety aspects

1.1 Operational records

Since the start of marine transportation of LNG by the “Methane Pioneer” in 1964, the safety record of the world LNGC fleet has always been the best of all types of merchant vessels.

This is due to the joint efforts of the parties concerned, i.e., charterers, ship owners, ship operators, classification societies and shipbuilders.

Each party has utilized its professional expertise and know-how to achieve “safety and reliability” in the following fields;

- Preparation of technical specification
- Evaluation and selection of shipyard
- Basic and detail design
- Vender selection
- Construction
- Quality control
- Commissioning
- Sea and gas trial
- Crew training and familiarization program
- Operation
- Onboard maintenance
- Drydocking

The ten (10) LNGCs delivered by MES (Table 1) including “AL ZUBARAH” (Fig.1) the first vessel for the Qatar LNG project, have contributed to the excellent safety record of the world’s LNGC fleet.

Table-1 LNGCs delivered by MES

Ship Name	Tank capacity (m ³)	Delivery	Project
Senshu Maru	Moss 125,000	1984	Indonesia(Badak)
Wakaba Maru	Moss 125,000	1985	Indonesia(Arun)
NW Swallow	Moss 125,000	1989	Australia
NW Snipe	Moss 125,000	1990	Australia
NW Sandpiper	Moss 125,000	1993	Australia
Al Khaznah	Moss 135,000	1994	Abu-Dhabi
Shahamah	Moss 135,000	1994	Abu-Dhabi, KHI*
Ghasha	Moss 135,000	1995	Abu-Dhabi
Ish	Moss 135,000	1995	Abu-Dhabi, MHI*
Al Zubarah	Moss 135,000	1996	Qatar

*Subcontracted

Fig.1 S/S “Al Zubarah”



1.2 Safety in Ship Design and Construction

We believe that this remarkable safety record could not have been established and maintained without superior ship design/construction, so let us look at the efforts made in the design and construction fields.

Firstly, the cargo containment licensors and the shipbuilders spent large amounts of money and time on research and development ranging from conceptual experiments to production technologies to satisfy the “ Safety & Reliability” requirements.

For example, in 1971 MES made a license agreement with Moss Rosenberg for the construction of Moss spherical tank system. Since then, we have carried out various tests, including the following, before building first our LNGCs.;

- + Welding test of 9% nickel steel and aluminum alloy 5083-O
- + Fabrication test of 9 meter diameter model tank
- + Cooldown test of four different tank insulation systems
- + Cooldown and gasfree tests of 9 meter diameter model tank
- + Fabrication tests of full sized spherical blocks
- + Cargo piping/insulation cool-down test

- + Model basin and wind tunnel test
- + Sloshing experiment

In this way, MES developed its own technologies as the best way to fulfill its responsibility as a shipbuilder.

Secondly, the cargo tank system design is very conservative.

In case of the Moss Spherical Tank System, the design of the cargo tank is carried out in the following steps;

- 1st step : A detailed 3D FEM stress analysis is done.
- 2nd step : A fatigue analysis covering the ship's design lifetime is done to ensure there is no possibility of fatigue cracks developing.
- 3rd step : A crack propagation analysis assuming a fatigue crack is done to assure cracks do not penetrate in the ship's lifetime.
- 4th step : A crack propagation analysis for 15 day after detection of leakage, assuming a penetrating crack, is conducted to design "partial secondary barrier" required for IMO independent type B tank.

In this way, double or triple level safety is assured in the design of cargo tanks.

Thirdly, an extensive and consistent QA/QC system applied throughout the design and production processes as the final key to ensuring the safety and reliability of the cargo containment system, and, in this regard, we are proud that MES is the first Japanese shipyard to receive an ISO 9001 certificate.

1.2 Cargo handling safety

The cargo handling system and associated instrumentation/control systems are the heart of LNGCs.

Cargo handling machinery and equipment are designed with sufficient design margin, and duplicated as appropriate, for example;

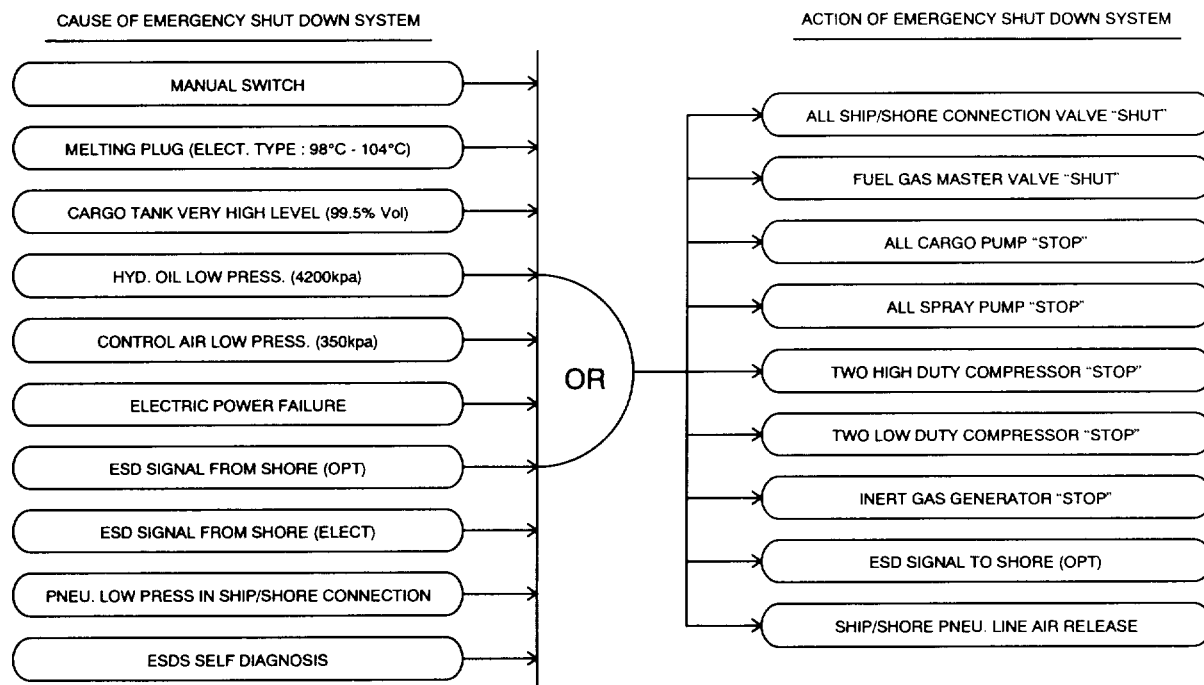
- + Duplicated installation - cargo pumps, H/D compressors, L/D compressors
nitrogen generators, level gauge (Capacitance + Float), Hydraulic power unit for valve control
- + Back-up function - H/D heater as back-up of L/D heater

Similarly, redundancy is also maintained for essential control systems such as;

- +UPS power supply (Uninterrupted Power Supply)
- +Separate sensor between control and trip
- +Duplicated data highway for CRT monitoring system
- +Self-diagnostics function

In addition, a fail-safe ESDS (Emergency Shut-Down System) is provided for ultimate safety as shown in Fig.2.

Fig.2 Emergency shut-down system



1.3 State-of-the-art technologies

The most advanced design technologies and design tools are utilized in the design of our LNGCs to ensure total reliability.

Computational Fluid Dynamics (CFD)

CFD is now being used in a wide range of applications, such as fluid dynamics and thermal plant design. Examples are shown below;

Fig. 3 shows the bow wave pattern and Fig.4 shows the gas flow pattern in the main boilers of the AL ZUBARAH.

Fig.3 Bow wave pattern

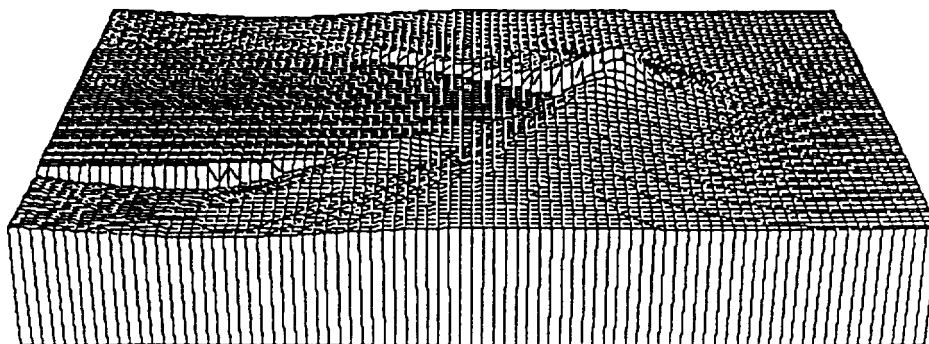
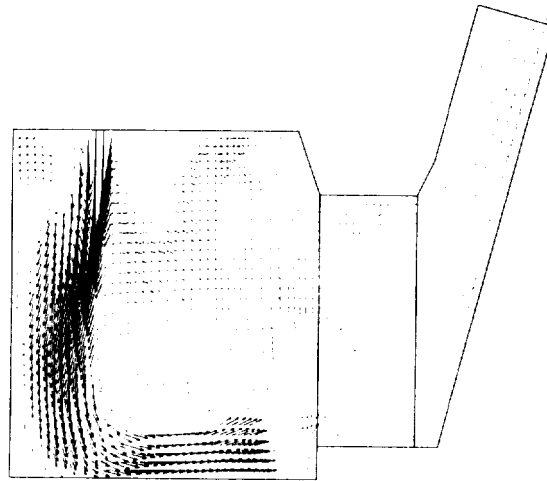


Fig. 4 Gas flow pattern in main boilers of the AL ZUBARAH.



Cargo Pump Speed Control

It is well known that a shock is observed in liquid piping when starting up the cargo pumps. This occurs when liquid accelerated to full speed in one or two seconds after start-up hits the pipes and valves.

Although, the piping system is strong enough to withstand such shocks, a soft start is used for psychological reasons. This is achieved via thyristor control by which supply voltage is gradually raised to start the cargo pumps at a slower speed.

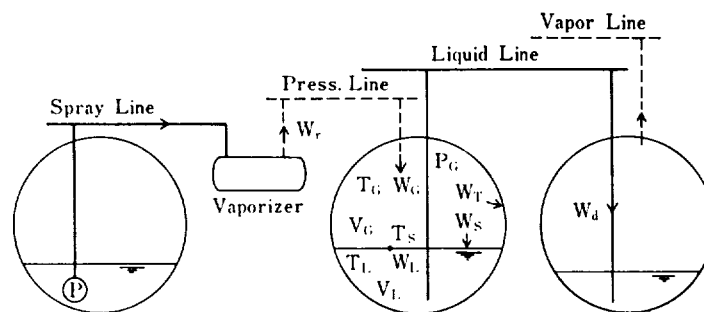
1.4 Contingency system

As mentioned above, safety is a primary consideration at every stage of design, and is further enhanced by contingency systems;

Emergency Discharge

Spherical tanks are very strong with respect to both external and internal pressure, and accordingly can be pressurized up to 2.0 bar to discharge the cargo by internal pressure, in case of trouble with both of the two submerged cargo pumps in each tank.

Fig. 5 Emergency discharge operation



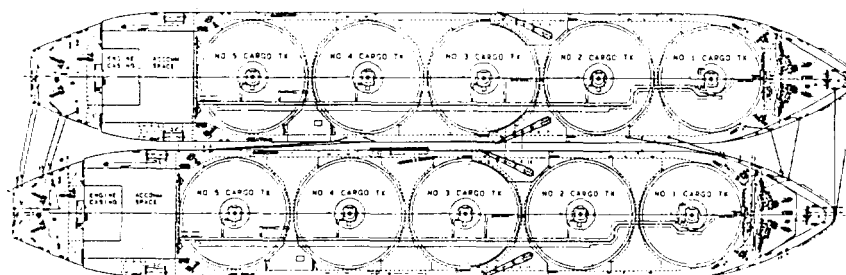
Schematic Flow Diagram of Pressure Discharge

Ship to Ship Transfer

Even if a ship is immobilized, its cargo can be safely shifted to another ship by ship-to-ship transfer. For LNG fleet, essential ship-to-ship transfer equipment is supplied as depot spare, and includes;

- + Twelve (12) cryogenic flexible hoses (250 mm dia.x 4m length)
- + Optical cable for ESDS link (80m length)
- + Power cable (80 m length)

Fig.6 Mooring pattern for ship-to-ship transfer



1.5 Maintenance

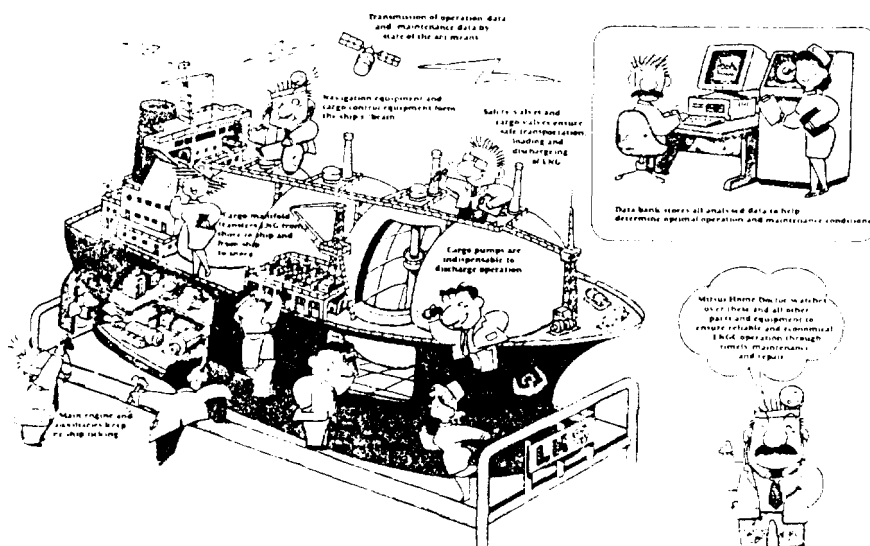
Good maintenance is essential for safe operation of LNG carriers, and it also promotes longer lifetime and reduction of overall maintenance cost.

Together with the establishment of an onboard maintenance scheme, the selection of a reliable maintenance/repair yard has a major influence on ship safety. In this respect, we have been proposing the "Mitsui Home Doctor" concept, which features a preventive or predictive maintenance philosophy to avoid trouble in operation.

Fig.7 Mitsui Home Doctor concept

MITSUI HOME DOCTOR

Expert Care for Your Vessel Throughout Her Lifetime



2. Environmental aspects

2.1 Propulsion system - greenhouse effect and acid rain

As is well known, almost all LNG carriers are powered by conventional steam turbine plants, however increasing demand for energy conservation and environmental friendliness has encouraged the selection of alternative propulsion systems.

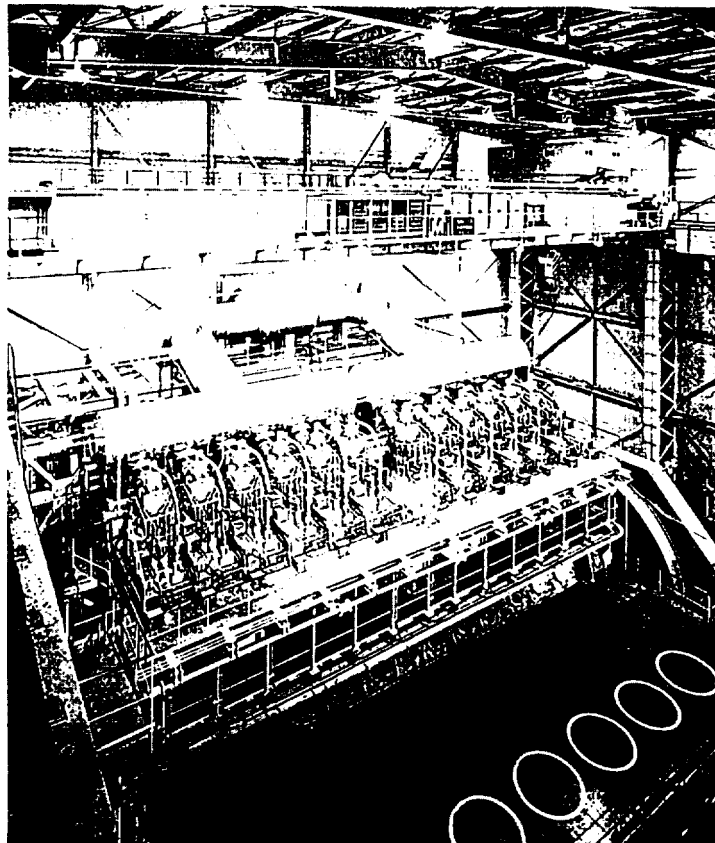
MES has developed GIDE (Gas Injection Diesel Engine) jointly with MAN B&W Diesel A/S. The world's first GIDE (Fig.8) with an output of 40MW was completed at our Chiba works as a stationary generating plant in July 1994.

Since then, valuable operational data and technical know-hows have been accumulated for future application to marine transportation as a "proven" design. GIDE is superior to conventional steam turbine in terms of fuel consumption as shown in Table-2.

Table-2

	Steam Turbine	GIDE
F.O.Rate	216 g/PS.h	133 g/PS.h
Thermal Eff'cy	30.5 %	46 %
FOC Ratio	100 %	66 %

Fig.8



Further, GIDE has big exhaust gas emission advantages.

As is well known, carbon dioxide is the major gas causing the greenhouse effect and NOx and SOx cause acid rain.

As shown in Table-3, GIDE only exhausts 50% of CO_2 compared to steam turbines. Further, the GIDE NO_x level is 25-30% lower than that of conventional oil-fired diesel engines and meets the guidelines proposed by IMO.

It is meaningless to mention SO_x level in exhaust gas because it depends largely on fuel oil sulfur content and the fuel policy (BOG vs. Fuel Oil), which might differ project by project. However, to offer a wider selection of fuels, modern LNGCs are now provided with a forcing vaporizer to fill the gap between the natural BOG and the gas fuel requirement.

Table-3

	Steam Turbine	GIDE
CO ₂	1.0Kg/KW.h	0.50 Kg/KW.h
NO _x	1.2 g/KW.h	15 g/KW.h

2.2 CFC(Chlorofluorocarbon) gases - ozone depletion

International awareness of the serious ecological impact on plants and animals including human beings caused by harmful solar ultraviolet radiation resulting from ozone depletion resulted in the Montreal Protocol which seeks to limit and phase-out CFC gases which are considered to be the major Ozone-Depleting Substances.

CFC gases also act as "greenhouse" gas. The ODP(Ozone Depletion Potential, CFC-11=1) and GWP(Global Warming Potential, CO₂=1) of certain gases are shown in Table- 4.

Table- 4

Name of gas	ODP	GWP	Montreal Protocol
CFC-11 (R-11)	1.0	4,000	stop by 1996
CFC-12 (R-12)	1.0	8,500	stop by 1996
Halon 1301	10.0	5,600	stop by 1994
HCFC-22 (R-22)	0.05	1,700	phase-out by 2030
HCFC-123	0.02	93	phase-out by 2030
HCFC-124	0.02	480	phase-out by 2030
HCFC-141b	0.10	630	phase-out by 2030
HCFC-142b	0.06	2,000	phase-out by 2030

New halon firefighting systems have been already prohibited since October/1/1994 by SOLAS 1992 amendments, so other fire-fighting systems are used in the engine and cargo machinery room of Qatar LNG project vessels.

R-11 and R-22 have been used as the refrigerant for the provision and air-conditioning system respectively. In the case of the Qatar project, alternative refrigerant and refrigeration plants were not commercially available at the design stage, so R-22 was selected for provision refrigeration plant, air-conditioning plant and refrigerating dryer of IGG as the less harmful refrigerant.

It seems that HFC gases such as HFC-134a would be promising as the alternative refrigerants, because HFC gases do not contain chlorine, which is the main cause of ozone depletion.

CFC gases have also been used as the blowing agent of polyurethane foam for the insulation of cargo tanks and cargo piping. The polyurethane foam for Qatar project was blown with HCFC 141b instead of CFC-11.

Similarly, polystyrene foam (Styrofoam) for cargo tank insulation was blown with HCFC-142b instead of CFC-12.

2.3 Marine pollution caused by anti-fouling paint

As a result of great efforts made by the Japanese administration and industries over the last few decades, Japan now has some of the most stringent regulations concerning marine pollution.

In 1990, the Japanese shipbuilding/ship repair industry took a great step towards combating marine pollution, namely by stopping the use of TBT (Tributyltin) containing anti-fouling paints for both new-building and repair work.

The influence of TBT on marine animals was firstly noticed in the late 70's in Europe, where commercial oyster fisheries suffered a great reduction in production as well as malformation of adult oysters. The analysis of malformed oysters indicated an abnormally high concentration of tin.

Triggered by this problem, government scientists started extensive studies of the influence of TBT on marine plants and animals, whether commercial or non-commercial products. Such research revealed various effects of TBT on the marine environment and led to the introduction of regulations to stop the use of TBT for small craft (below 25m in length), being first applied in France in 1982.

In Japan, periodical monitoring of the contamination levels in sea water, the sea bed and animal samples has been performed for substances believed to be toxic or having a negative influence on plants and animals.

In 1990, measurements showed 0.06 to 0.75 ppm TBT concentration in fish samples taken from a major bay, necessitating urgent action.

Although there were teething problems at the beginning with newly developed TBT-free paints, they have now reached to the same level of effectiveness as TBT-containing paint, and this policy has been widely acknowledged by the marine world and is now being followed by other countries under the guidance of IMO.

2.4 Marine pollution caused by garbage and sewage disposal

If dumped to sea, garbage and sewage will damage not only beautiful scenery but also threaten the ecology of marine resources.

For example, a lot of sea birds and turtles die every year due to ingestion of plastic garbage.

To meet MARPOL (Convention for the Prevention of Pollution from Ships) requirement the Qatar Project vessels are provided with;

- + Garbage compactor + incinerator
- + Sewage treatment system + Holding tank (50 persons x 4 days)

2.5 Shipboard life - Safety and amenity

Attention is also paid to the safety and amenity of shipboard life which is the background for safe navigation and operation of LNGCs.

The main areas of concern and our responses are;

+ Asbestos-free

Because asbestos is known to cause lung cancer, no asbestos is used.

+ Noise

The stringent noise levels below, targeted at the design stage, were successfully achieved in sea trials.

Table-5

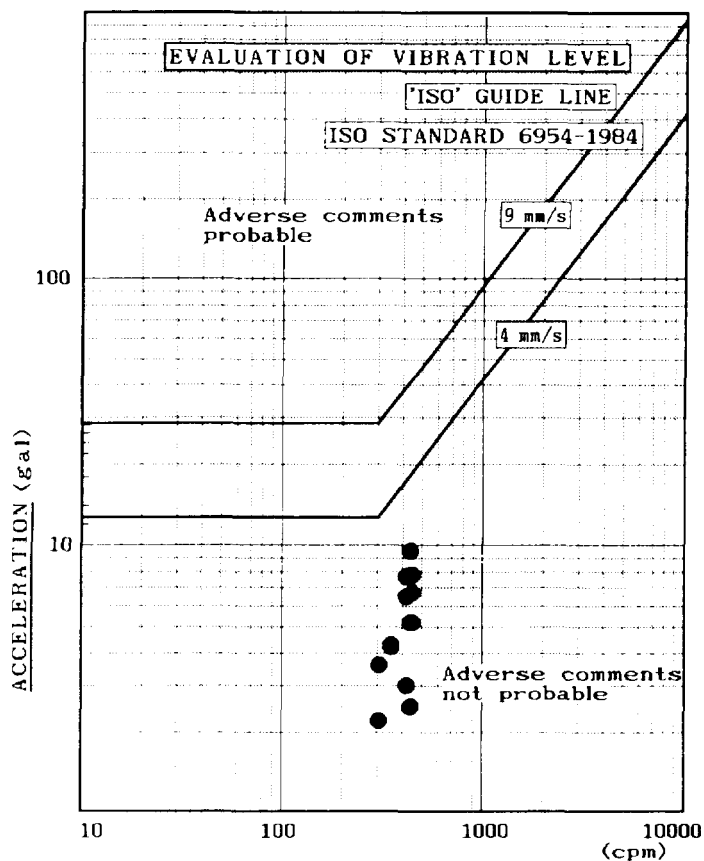
Space	IMO code	Design.	Mmeasurement
Private cabin	60 dB(A)	55 dB(A)	45 - 55
Cargo control room	65	55	55
Engine cont. room	75	70	65
Engine workshop	85	75	72

+ Vibration

Vibration is also vital to the comfort of shipboard life, therefore extensive analysis including 3D FEM was done at the design stage.

The measurements obtained in the sea trials show excellent results, as shown in Fig.9

Fig. 9



3. Conclusions

Various efforts in relation to safety and environmental aspects in LNGC design are presented in this paper.

Thanks to the efforts by people involved in LNG business, we can now enjoy an excellent reputation for safety and environmental friendliness.

And Mitsui Engineering & Shipbuilding Co., Ltd.(MES) will continue its leadership in the design and construction of “safe and green” LNG carriers, for the benefit of the world.

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2. “ What LNG Carrier Does the Market Need”, Halfdan H. Iversen, LNG-10
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“Middle East Gas : Prospects & Challenges”

Session (9)

Safety & Environmental Considerations in LNG Operations and Transportation

Paper No. (9-5)

The Challenge for Safe Transportation of LNG

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Japan

The Challenge for Safe Transportation of LNG

**Tokinao Hojo,
Director
Mitsui O.S.K.Lines, Ltd.**

Almost 30 years have passed since LNG transportation to the Far East began on a large-scale. Supported by steady efforts and cooperation from all parties concerned, safe and environmentally friendly transportation has been well established. As the chart shows, in conventional shipping area like bulker and tanker trade, it is the reality that certain degree of accidents have been recorded, which is much higher than what is in LNG carriers. In regard only to LNG carriers, there have been no serious accidents in the past.

I would like to give the following points as the reason for such accomplishments.

1) Common understanding has penetrated within parties concerned with the LNG business, including sellers, buyers, shipping companies, shipyards so on, that there is a huge risk in the transportation of hazardous cargoes. The realization result in creating a structure to cooperate with each other and to act as one body for safe operation.

2) Apparently, it seems that there is a conflict of interests among the Charterers, Shipowners and shipbuilders with some clauses of their contracts. But they clearly understand that the most important task is to keep safe and stable operations and that in the long-run, they will profit through cooperative actions. Therefore, naturally, they behave in harmony with each other.

3) The number of parties concerned with LNG transportation, that is, the shipbuilders and shipping companies, are extremely limited. Only the first-class companies with their rich know-how and well trained experts, can remain in the LNG business. The field of LNG transportation is free from a sense of excess competition existing in other categories of the ocean transportation. I believe that there is no LNG transporter in the market who undertake the contract terms below their cost level. And the project members or charterers also will not demand transporters to do so at the expenses of the safety standard.

4) Because a limited number of shipbuilders and shipping companies are participating in the LNG transportation market, the know-how on LNG, which they accumulated from their experiences in the previous projects, were easily fed back into the succeeding new projects. Thus, players in the current LNG transportation market are well experienced professionals only.

Suggestion

While the safety record for LNG transportation has held up extremely well until now, I assure that there are several problems to tackle with in order to continue with such good performance.

1. Management for Aged LNG vessels

Based on the assumption that LNG vessels have a much longer life than oil tankers or bulkers and can be used for years longer, as I have stated at various occasions in the past, I suggest that the existing vessels should be utilized in extension, in order to reasonably cut down the capital cost of transportation and to stabilize the shipbuilding market. Actually, several projects are going to decide to use the existing vessels by extension after the end of the original contract period, instead of replacing them with new buildings.

But unless the vessels are well maintained under the long term plan and kept in good condition, the extensive use of existing vessels could be a hindrance to safe and stable transportation. Both owners/ship managers in charge of operations and maintenance, and shipbuilders undertaking repairs and dry dock must accumulate sufficient technical knowledge for treating older vessels to materialize a long life of vessels under the sustainable good condition.

2. Wrestling with marketization

LNG business has been developing and will be increasingly diverse in respect to exporting and importing areas. In the starting-up period, a new gas-route project could choose the way to use existing vessels, like the decision of the Nigeria or Trinidad project, aiming to reduce the transporting costs.

But too much coherence in cost saving measures may lead sub-standard LNG vessels to appear in the market. Judging from my long experience in LNG transportation business, shipping companies had secured fine crews and carried out sufficient maintenance, on condition that they could expect a reasonable return from transportation business. Recently, it seems that the parties concerned, who are accustomed to safe operations, are focusing more positively toward cost saving and may be becoming a bit insensitive toward maintaining safety. Since economical loss would be incalculable once a serious accident occurs, all the parties should make their first priority that of safe operation. Especially in LNG, only one big accident will be enough to spoil the confidence in LNG as a clean and safe energy source. The whole LNG industry, not limited to the direct parties, might suffer serious setbacks from such an accident. I would like to arouse everyone's attention to this point.

3. Deficit of qualified officers on worldwide-wide scale

At present, more than half of the qualified classed officers boarding on the world fleet, come from OECD countries. As far as LNG vessels are concerned, almost all officers on board are from developed countries. But as you see from this chart, every developed country is facing a decrease in the number of seafarers. The tendency for decline will only increase in the future. On the contrary, LNG fleets will need more and more qualified seafarers. We can expect considerable difficulty in supplying fine crew on LNG vessels. Trying to overcome this difficulty, our company has been employing graduates from merchant marine colleges every year and training them to become high quality officers, by the accumulated experience of those working in the office and the duty on board, according to the long term training plan. We think it is important to train loyal house crew to keep a safe and stable operation over a long period, even though it sometimes takes much time and money. For this purpose, the need for a long term commitment is required and only the first-class shipping companies, as I mentioned above, are capable to bear the transportation responsibilities. This is how it should be.

4. Growing interests for environmental protection

Present international trends are heading for the ratification of the HNS treaty. All the parties concerned with LNG projects must carefully consider not only safe operation of the directly-related vessels or terminals, but environmental protection. Without such consideration, economical losses are sure to be extraordinary, especially in the sea area of developed countries.

Conclusion

Considering the points above, I would like to emphasize that it is an essential factor for the success of the LNG project to select first class shipping companies. The first class shipping concerns must fulfill the various requirements, as :

1. It has a training program for sea officers based on the long term management plan;
2. It has established a support system from the shore and has know-how relating to the maritime affairs, legal matters, or risk management etc.;
3. It must have financial strength and a stable management policy, both of which are required for precedent investments; and
4. It has high technical standards and responds properly to every situation, including vessel designs, operations and repairs.

Only a few independent shipping companies and the oil majors' subsidiaries meet all these qualifications in the field of LNG transportation. MOL, as one of these companies sharing a part of the burden, will devote all our energy to realize safe and stable transportation successfully.

Worldwide LNG transportation is carried out by a very limited number of parties, when comparing with other energy transportation, like crude oil or steaming coal. Information can be obtained from shipping companies, shipbuilders or LNG project participants in common beyond the scope of their respective projects. I would like to suggest that all the parties should promote the exchange of information and accumulate necessary know-how, particularly involving the risk management skills. In this context, I am willing to support the idea of an international convention, like this Doha Conference, to be held regularly.

In the year 2000, when the Qatar project will reach its plateau, we, Mitsui O.S.K. Lines, Ltd. are going to be involved in the possession and operation of 35 LNG vessels, by the barest of estimations. I always believe that the best transportation scheme for LNG is realized by which first class shipping companies will possess, operate and manage the vessels by themselves. Fortunately, it has been achieved in the Qatargas LNG project. Making the most of our knowledge, know-how, and highly-skilled techniques of our loyal house-crew, cultivated from the experience of various projects, we are going to contribute in any way possible to build up the safe transportation in the Qatar LNG Project.



“Middle East Gas : Prospects & Challenges”

Session (9)

Safety & Environmental Considerations in LNG Operations and Transportation

Paper No. (9-6)

LNG Plant : Safety Considerations

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LNG Plant: Safety Considerations

**Michael Halata
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TEXT SUMMARY

I. Process/Design Related Safety Issues

- * Required information on design basis process parameters
- * Hazardous by-products or side-reactions
- * Identification and communication of processes subject to violent reactions
- * Inadequate evaluation of the natural environment or the plant site
- * Requirement for operating the plant at extreme process conditions

II. Plant Operations and Safety

- * Detailed descriptions and recommended procedures for operating all sections of the plant. This should include start-up and shut down procedures, but most importantly trouble-shooting guidelines or deviation from normal guidelines.
- * Training programs
- * Operations supervision
- * Housekeeping programs
- * Permit systems
- * Emergency response plans
- * "Situational Awareness"

III. Equipment Failures and Plant Safety

- * Unknown hazards built into the design of equipment
- * Inadequate or misunderstood process controls

- * Lack of necessary "fail safe" instrumentation and E.S.D.
- * Construction quality criteria or lack of discipline to enforce the same
- * Inadequate adherence to material quality specifications
- * Defective fabrication
- * Corrosion or erosion
- * Metal fatigue
- * Maintenance programs
- * Actual operations excessively exceeds design limits (over/under)

IV. Loss Prevention Programs

- * Clearly assigned responsibility
- * An accident prevention program (Hazard recognition and elimination)
- * Sufficient fire protection manpower, equipment, organization, and training
- * Emergency preparedness
- * Effective root cause analysis investigation of accidents
- * Risk management

LNG FACILITIES: SAFETY

It is a fact of life that whenever the human element is involved there is always the chance for error. We will never be able to totally eliminate mistakes. What we can do is strive to minimize the number and the magnitude of the mistakes that potentially could be made. The modern approach is to focus on the "system" and not the lowest common denominator (i.e. fixing blame on the operator). And in the case of the inevitable, when the mistake is made and a potentially dangerous condition has developed, we can be thoroughly prepared to limit the impact both from a safety and a production standpoint.

What must we do? What should we consider when we take on the challenge to safely operate and maintain an LNG facility?

Prior to a plant start-up we must verify that the plant is designed for safe operation under all conditions, normal and abnormal. Early on we must develop and, when the plant is commissioned, implement programs that will ensure that every effort is made to prevent an unsafe incident.

We must consider:

- Safety issues related to the LNG process
- Plant Operations approach to safety
- Equipment failure and its impact on safety performance
- Loss Prevention programs

Let's look at each of these areas in a little more detail.

PROCESS RELATED SAFETY ISSUES

Beginning with the process itself let's look at some of the things that may be overlooked or that exist which could contribute to an unsafe condition in an LNG facility:

- Required information on design basis process parameters. Inadequate or lack of design parameter information can be a problem when feed stock compositions change. The operator expects and is accustomed to one thing but when a feed composition change takes place, especially an unexpected one, the operator may have a tendency to overreact.

- Hazardous products or side-reactions. Examples of these points are the problems associated with cryogenic shock-chilling of equipment leading to brittle fracture and spent caustic or amine disposal.
- Identification and communication of processes subject to violent reactions. An example of this process is the potential for LNG Tank rollover.
- Inadequate evaluation of the natural and plant site environments. Are you ready for that once in every 100 years storm that takes place the first year of operation?
- Requirement for operating the plant at extreme process conditions. Are your plants or operators capable of safe operations during transient cases? 10% below minimum turndown or 30% above maximum design.

These items and others must be considered during the initial and detailed design phase of a project. Also important, though, is to ensure that the correct information is passed on to the plant operations, maintenance and engineering organizations to be included in their manuals, procedures and training.

OPERATIONS AND SAFETY

What are some of the things that the plant operations organization has control of or is responsible for that can (and do) influence a plant's safety performance?

- Detailed descriptions, trouble-shooting guidelines and recommended procedures for operating all sections of the plant. This information should include start-up and shut down procedures. Good procedures are probably the most utilized "tool" by operators in an operating plant. Standard Operating Procedures (SOPs) and good administrative procedures are a must in any plant. Who are the best people for writing these procedures? One option is having the operators write the procedures based on their familiarity and experience with the individual sections of the plant. But it is important that the different engineering disciplines review and approve them not so much from an operational point of view but from a technical aspect.
- Training programs. Training is one of the most important steps one can take to assure safe operations in an LNG plant. Training should be continuous. Initial training, refresher training, training on new equipment or new technologies, safety training, firefighting training; all this and more should have a high priority placed on it.

- Operations supervision. This point cannot be emphasized enough. Experienced first and second line supervisors are a necessity not only during the start-up of a plant but during the normal operation of a plant. These are the people who are going to guide the operators (especially the inexperienced ones) through upsets or abnormal events.
- Housekeeping programs. Develop a good housekeeping program. Inadequate housekeeping practices will contribute to accidents, fires and lost production.
- Permit systems. We all have permit procedures in our plants. But are they adequate? Do they cover all possible scenarios? Do you have a system in place to verify that all parties are adhering to your permit procedures? Never allow exceptions unless a proper review and risk analysis has been done.
- Emergency response plans. These should be developed by a team of all the different departments. In a big emergency everybody is involved in some way. Develop them and then practice. Set up simulated, plant-wide emergency situations.
- "Situational Awareness". "What If" sessions are great for getting people to think about situations they normally wouldn't.

EQUIPMENT FAILURE AND PLANT SAFETY

Some of the most catastrophic incidents that have happened in the industry have been due to equipment failure in an operating plant. Although some can be contributed to operator intervention (or lack of) a large number of them were not under plant operations' direct control. However even though the operations organization cannot always control the problem, an increased awareness on their part can help identify the potential hazard before it becomes an incident.

Some of the things that can contribute to equipment failure are:

- Unknown hazards built into the design of equipment.
- Inadequate, malfunctioning or misunderstood process controls.
- Lack of necessary "fail safe" instrumentation and E.S.D.

These three points must be covered during the design phase and then followed up on. It is important not to overlook these points when new equipment is added or modified.

- Construction quality criteria or lack of discipline to enforce the same

- Inadequate adherence to material quality specifications (Did Procurement purchase what was specified or engineered?)
- Defective fabrication/manufacturing

Although these three points are control issues for either construction or procurement, the operations organization needs to verify that the proper checks were implemented.

- Corrosion or erosion
- Metal fatigue
- Maintenance programs
- Material verification

Well thought out and well maintained predictive/preventative maintenance and inspection programs will identify (leading to a repair) many of those potentially hazardous failures while they are still minor maintenance issues.

- Actual operations excessively exceeds design limits (over/under)

Over pressuring, over heating, or dropping below the critical exposure temperature of a piece of equipment can cause a failure of that equipment.

With proper training and information the operator should be able to recognize the developing hazard and take the correct actions. In the event, though, if one should have a case when a piece of equipment has exceeded its design limits, procedures should be in place to correctly return it to normal conditions followed by the appropriate testing to verify the integrity of the equipment.

LOSS PREVENTION PROGRAMS

After considering the large number of things that can be contributed to the chemical process, to operational failures and to equipment failures that can cause accidents or unsafe situations, what is left? How about an effective loss prevention program? Some of the things in this category that are often overlooked or not considered are:

- Clearly assigned responsibility
- An accident prevention program (Hazard recognition and elimination)
- Sufficient fire protection manpower, equipment, organization, and training
- Emergency preparedness (In plant and community)

- Effective root cause analysis investigation of accidents
- Risk management

All the things mentioned can be implemented or corrected. Where does it start?
With us.

With proper planning, training, procedures, programs and experienced operations input we can ensure that every aspect of safety will be covered in the design and the operation of our LNG plants. We have to realize that just because the plant is up and running and making a profit that safety awareness and development must not stop, but rather must be continuously reinforced.

If plant management puts in the time and effort and sees that the plant operating personnel does the same, then one can control the losses that can be contributed to accidents or failures.

REFERENCES:

- API 750
- OSHA 1910
- NFPA 59A

**SECOND DOHA CONFERENCE
ON NATURAL GAS**
March 17 - 19 , 1997
DOHA - QATAR



مؤتمر الدوحة الثاني للغاز الطبيعي
١٧ - ١٩ مارس ١٩٩٧
الدوحة - قطر

“Middle East Gas : Prospects & Challenges”

Session (10)

Economic and Financing Challenges

CHAIRMAN

Dr. Hussain Al-Abdulla

Project Finance Team Leader,

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QATAR

**SECOND DOHA CONFERENCE
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Session (10)

Economic and Financing Challenges

Paper No. (10-1)

Financing LNG Projects - the Role of the Capital Markets Going Forward

**Daniel S. Lief
Vice President-Investment Banking Division,
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U.S.A.**

FINANCING LNG PROJECTS

THE ROLE OF THE CAPITAL MARKETS GOING FORWARD

presented by

DANIEL S. LIEF

Goldman, Sachs & Co.

March 19, 1997

[SLIDE 1]

Goldman Sachs has been involved with the State of Qatar, QGPC, Mobil Oil and Ras Laffan for three years in connection with the planning, development and ultimately the financing of the Ras Laffan liquified natural gas project. We continue in the role of financial advisor to Ras Laffan. We also served as lead underwriter in connection with the company's \$1.2 Billion bond offering which was completed this past December. This bond offering closed on the same day Ras Laffan closed a \$1.35 Billion syndicated loan/ECA facility involving 25 international banks and three export credit agencies. This presentation will focus primarily on the bond offering - the lessons we've learned and the implications for other major project financings. There is obviously precedent for capital markets financings for projects but Ras Laffan clearly stands out - It was the largest bond offering ever for a true project financing; it was the first bond offering for a middle eastern project; and it was the first long bond issued by a middle eastern issuer [including sovereigns].

Let's start out looking at the questions people are asking in the aftermath of Ras Laffan's financial closing:

QUESTIONS FOR DISCUSSION [SLIDE 2]

- Why did the sponsors [QGPC and Mobil] plan for and pursue a bond offering given the history of LNG financings?
- Has there been a change in the capital markets? (The Ras Laffan offering was so much larger than offerings for other projects over the last several years.)
- What are the implications for future LNG Projects specifically and more generally for Project Financing in the emerging markets? What about major gas fired power plants or major pipelines in India, China, should we expect to see these projects financed in the capital markets?

Background on Ras Laffan will be helpful in thinking about answers to these questions - its history, development to date, and plans for the future - and then details on the financing which has been put in place.

RAS LAFFAN [SLIDE3]

- A Qatari joint stock company that was formed to engage in the business of producing and selling LNG, condensate and other hydrocarbons.

- Ownership:

QGPC - 70%

Mobil - 30%

- Planned LNG capacity:

10 million tons per year

- Projected Development Cost:

Trains one and two - \$3.4 billion

Trains three [and four] - over \$2 billion

- Timing:

Train one completed - September 1999

Train two completed - September 2000

Trains three [and four] - To be determined

This, in summary form, is the anticipated capitalization of Ras Laffan assuming that two trains are constructed.

CAPITALIZATION [TWO TRAINS] [SLIDE 4]

Uncovered Bank Loans	\$	450
ECA Guaranteed Facilities		900
Bonds		<u>1,200</u>
		2,550
Mobil Equity		250
QGPC Equity		<u>600</u>
	\$	3,400

DESCRIPTION OF THE BONDS [SLIDE 5]

Issuer:	Ras Laffan LNG Company Limited		
Ratings:	Moody's	A3	
	S&P	BBB+	
Amount:	\$1.2 Billion		
Maturity/Avg Life/Rate:	\$400 Million	10 years/7 years	7.628%
	\$800 Million	17.5 years/15 years	8.294%
Ranking:	Senior, Secured, pari pasu with bank/ECA facilities		
Security:	Rights to receivables from KGC and offshore accounts; security interest in assets under Qatari and New York law; security interest in Korea Gas SPA under New York law		
Sponsor Support:	Includes Completion Guarantees and equity contributions		

I will come back to a more detailed discussion of the bonds later as we do a terms comparison between the Bonds and the Bank/ECA financing but for now let's get to the first question - "Why did the sponsors pursue a bond offering given the history of LNG financings?"

My answer begins over three years ago when the sponsors first formed their Finance Team - hiring Goldman Sachs as Financial Advisor and Latham & Watkins as Counsel. At that point development plans were in place, but no SPAs had been signed and bid packages for the EPC contract had not yet gone to contractors. We were working with an assumption that in excess of \$5 billion would be spent. Both sponsors had watched major project financing get delayed and otherwise bogged down and saddled with huge amounts of sponsor support. The sponsors had an appetite for the required equity which hopefully would not exceed 30% of cost; and they were willing to guarantee completion; but beyond that they had no interest in further guarantees or financial support.

There was clear encouragement for an "unconventional " approach which might avoid pitfalls. There was also recognition that success would depend on having a detailed financing strategy [a plan] as soon as possible.

The team's earliest conclusions were critical to the formation of the finance plan and, if I do say so myself, were 'spot on'.

- The Ras Laffan EPC contract was to be huge and was expected to be sought aggressively by the world's biggest and best engineering and construction companies. We all convinced ourselves [and eventually convinced the non-finance types at QGPC and Mobil] that there would be no downside, and potentially very significant upside, in requiring that all EPC bids include a fully underwritten financing package.
- Japanese financial institutions had been the primary source of financing for past LNG projects based on concepts of 'import financing', but it might be a mistake to rely on them too heavily for Ras Laffan 1) There was no certainty that the majority of the LNG buyers would be Japanese even though there was then, and there remains today, an expectation that significant volumes would be sold into Japan. 2) Early reliance, in this case, on Japanese import financing would not lead to the most attractive financing package.
- Commercial Banks and ECAs were the traditional lenders for major international projects and were expected to be the major players in the Ras Laffan financing. At the same time, however, given the size of the project and the size of other projects being developed around the world and in Qatar by others, we were concerned about capacity in the market. We concluded that the finance plan, by necessity, must

look broadly at all potentially attractive markets around the world - including of course the bond market.

- The project economics would not support 70% debt without a tranche with a longer maturity than the 8.5 years (post completion) which the banks and ECAs would provide.
- With all of the foregoing, we predicted a financing package which would include multiple ECAs, a large number of commercial banks, bond investors, and potentially other financial institutions [e.g. Japanese trading companies]. There was an obvious need for us to develop a standardized set of financing conditions which would hopefully work for all potential lenders and anticipate intercreditor and other issues. This would hopefully lead to efficiency and success in the end.
- If we would eventually be looking to the bond market, it was likely that the sovereign, the State of Qatar, would be getting a bond rating (either real or implied). Credit ratings important (if not an absolute requirement) in the bond market and a project can not get a rating if the sovereign itself is not rated. The process with the rating agencies was started very early due to an overall nervousness we all felt. The rating agencies had not done much at all in the middle east and they certainly knew very little about the State of Qatar. At the same time senior Qatari's at the relevant ministries had no relevant experience with credit rating agencies.

The sponsors quickly concluded that planning for a bond offering was critical given the size of the project, the long lead-time involved and the uncertainty surrounding the project at that time.

Goldman Sachs advised the Finance Team that a bond financing could be very attractive compared to alternatives and that such a financing should be achievable for Ras Laffan.

From a borrowers perspective, the attractiveness of a bond financing is usually based on long maturities, favorable covenants and ease of execution. Interest rate can also be a major factor but that is very much a question of the market at the time.

Our advice on 'doability' was based on 1) the extremely high quality of the project and its sponsorship and also 2) the extraordinary growth we had seen in the market for emerging market bonds

The growth we observed in emerging market debt investment in late 1993 has proven to be more than a short term 'blip' on the charts. While growth has slowed, levels of investment have remained at very high levels. Investors, largely in the U.S., but also around the world, were initially attracted to the emerging markets by the yield premiums

available compared to other markets. In addition they have become more knowledgeable and therefore more comfortable with emerging market and project financing credits generally. We worry less today about a 'Mexico Crisis' destroying the market than we did a year ago. Investors are extremely sophisticated in their analysis and focus on relative values between countries and across regions and continents.

THE EMERGING DEBT MARKETS [SLIDE 6]

NET PORTFOLIO FLOWS 1990-1996 (BILLIONS) (a)

Year:	1990	1991	1992	1993	1994	1995	1996
Amount:	3.0	12.8	13.2	38.3	32.2	33.7	33.0

Another notable trend has been the increase in maturities available. As recently as 1990, the bulk of capital markets transactions in international markets had maturities of less than 10 years. The search for yield during this period of historically low real interest rates and a relatively steep yield curve, has pushed investors out on the maturity spectrum making increasingly longer terms available for issuers. Financings as long as 30 years have been done in Mexico and Colombia.

EMERGING DEBT MARKETS [SLIDE 7]

Bond Issuance by Maturity 1990-96

Year:	1990	1991	1992	1993	1994	1995	1996
Total Issuance:	\$5.7bn	\$9.8bn	\$19.1bn	\$50.9bn	\$41.3bn	\$49.0bn	\$93.5bn
Number of Issues:	52	81	164	417	316	318	512
Greater than 10 Yr. Maturity:	0.00%	0.00%	0.13%	8.61%	2.65%	5.06%	10.34%

Who are the buyers of this paper? For investment grade paper, it is your usual suspects - major insurance companies, investment advisors and pension funds.

For non-investment grade paper it is a combination of 1) "Cross-Over Buyers", in search of yield and diversity, and 2) Mutual Funds specializing in emerging market debt, high yield debt and equity.

Perhaps the most interesting phenomena has been the Cross Over buyer. These are traditional investment grade corporate buyers who have realized that international project financing and emerging market debt can be high quality investments. These buyers have entered this market in size and that move can be tied to the very low bond yields available on their more traditional investments. The argument has also been articulated that since emerging market investments are not perfectly correlated with more traditional fixed income securities, adding emerging market credits to an investment portfolio can actually reduce its blended risk profile.

In analyzing the credit, Cross Over buyers are as interested in the underpinnings of the local economy as they are in the project itself. They typically work under portfolio limits with respect to a given sponsor and a given country.

The remainder of the buyers, the Funds, tend to approach the bonds purely from a value perspective. They are looking to balance their portfolios from a geographic, industry, credit and term perspective.

On the next slide, I have provided a list of buyers for emerging market project bonds.

INSTITUTIONAL BUYERS OF PROJECT BONDS [SLIDE 8]

Insurance Companies	Investment Advisors/ Pension Funds	Mutual Funds	Banks and other Institutions
Prudential	Alliance Cap	Putnam	Bank One
IDS Life	JPMIM	Mass Financial	SBC/UBS
New York Life	MSAM	Fidelity	Swiss regional banks
Reliance Life	Huff Asset	Vanguard	Paribas
Provident Life	T. Rowe Price	Keystone	German Landesbanks
Northwestern Mutual	Delaware Mgmt	Kemper	Japanese Leasing Cos
CIGNA	Cap Research & Mgmt	Franklin	First Union
Phoenix Life	Nomura Cap	First Investors	Korean banks
Met Life	Equitable Cap	MLAM	Banco Santander
Teachers Insurance	Calif Regents	Prudential	
Axa	State of Oregon	Invesco	
	State of Colorado	Miller Anderson	
	Loomis Sayles	Janus Funds	
	Standish Ayer & Wood	Oppenheimer	
	Strong Corneliuson	DIT/DWS	
	Invesco		
	Waddell & Reed		

Finally, I thought an analysis of who bought the Ras Laffan bonds might be interesting

DISTRIBUTION OF RAS LAFFAN BONDS

[SLIDE 9]

TOTAL NUMBER OF INVESTORS:	70
AVERAGE SIZE OF INVESTMENT:	\$15-20 million
LARGEST INVESTMENT:	\$125 million
U.S. INVESTORS:	82%
INSURANCE COMPANIES:	15%
INVESTMENT ADVISORS/PENSION FUNDS:	50%
MUTUAL FUNDS	23%
BANKS and other INSTITUTIONS:	12%

The next question is - "What made the bonds so attractive that the sponsors bumped the size from \$400 million [as originally anticipated] to \$1.2 billion?" This next slide provides a summary comparison between the bonds and the Bank/ECA financing but the answer is actually very simple

- The price was right
- Longer maturities would make it possible to use more debt in total
- The bond proceeds were immediately available - there were no conditions precedent

Note that I have compared 'All-in Cost' not 'Interest Rate'. The reason for that is that people often look at coupon alone on a financing and ignore commitment fees, up-front fees, and other related fees and costs. The comparison which appears here is between 'apples' and 'apples'.

RAS LAFFAN

[SLIDE 10]

A COMPARISON BETWEEN THE BONDS AND THE BANK/ECA FINANCING

	BONDS	BANK/ECA
PRINCIPAL AMOUNT	■ \$1.2 Billion	■ \$1.35 Billion
ALL-IN COST	■ 8.65%	■ 9.60%
MATURITY/AVG LIFE	■ Tranche 1: 10/7 ■ Tranche 2: 17.5/15	■ 13/8.5
CONDITIONS PRECEDENT TO FUNDING	■ None	■ Signed 2 nd SPA ■ Equity invested first
EFFICIENCY OF EXECUTION	■ 6 months ■ work from bank documents ■ no negotiations	■ 18 months ■ extensive negotiations
RATINGS REQUIREMENT	■ yes	■ no

SECURITY	■ assets, contracts	■ assets, contracts
-----------------	---------------------	---------------------

A caveat is important here on pricing. Bonds will not always be priced more attractively than Bank/ECA financing. The results of a pricing comparison like this will always be a function of the relative attractiveness of the particular region to the bond investors as compared to its attractiveness to the banks and the ECAs and also the general level of interest rates in the bond market.

Pricing in the Bond Market is sensitive to a whole host of external economic and political factors and on the whole is much more volatile than Bank/ECA pricing. In addition it is important to keep in mind that it is not unusual to see bond investors aggressively seeking opportunities in a certain country or a region while at the same time banks and ECAs continue to charge a premium for loans in that region — just as often the bond market may be closed or very expensive while the banks and the ECAs are lending in the given region on favorable terms - attractive pricing and longer maturities.

Finally, it is important to circle back to where I started when I told you that the success of the Ras Laffan bond financing was very much tied to the fact that this was an extremely high quality project. This next slide summarizes those factors which are most important to the rating agencies and the bond investors

WHAT MAKES A PROJECT “HIGH QUALITY” ? [SLIDE 11]

- Sponsor credit quality
- Strategic importance
- Local government support
- Revenue stream - credit quality of taker and predictability
- Reserves [or fuel supply]
- Financial structure [e.g. completion undertakings, security, offshore accounts]
- Construction and operation
- Financial projections

Most of you who are thinking about how to finance major LNG projects are also, I am sure, very interested in the development and financing of large gas fired power plant projects in emerging markets. With that in mind, I thought it would be interesting to look at a comparison between Ras Laffan and Paiton, a high quality power project in Indonesia which was financed last year.

A COMPARISON BETWEEN TWO PROJECTS**[SLIDE 12]**

	RAS LAFFAN	PAITON 1
BUSINESS	production and sale of LNG, condensates and other hydrocarbons	ownership and operation of 1230MW coal fired power plant
LOCATION	Qatar	Indonesia
CAPITAL COST	\$3.4 Billion	\$2.5 Billion
SPONSORS	QGPC - 70%; Mobil - 30%	Mission Energy - 40%; GE Capital - 12.5%; Mitsui - 32.5%; PT Batu Hitu Perkasa - 15%
SOVEREIGN RATING	Baa2/BBB	Baa3/BBB
PROJECT RATING	A3/BBB+	Baa3/BBB
CUSTOMER/ CUSTOMER RATING	Korea Gas Corporation (state owned utility) (A1/AA-, implied)	PT PLN (state owned utility) (Baa3/BBB, implied)
SIZE OF BOND OFFERING	\$1.2 Billion	\$180 Million
MATURITY/AVG LIFE	17.5/12 (overall 2 tranches)	18/15.5
INTEREST RATE (SPREAD OFF US TREASURIES)	+171.17 bp (weighted average 2 tranches)	+297 bp
CURRENCY OF REVENUES	U.S. Dollar	Indonesian Rupiah (adjusted to reflect US\$/Rp exchange-rate fluctuations)
CRITICAL RISK FACTORS	Regional Political Risk (i.e.deliverability)	- Disruptions in fuel supply - Construction risk

The most important thing to take away from this comparison is that a power plant project in an emerging market, which in most cases will be selling its output domestically, will not usually approach the attractiveness of an LNG project which is export oriented, selling to a very strong credit, and dealing in US dollars with no convertibility risk. Beyond the credit strength of the foreign customer, the ability to capture dollar revenues in off-shore accounts is important.

This final slide summarizes the most important lessons we take away from our experiences as financial advisor to Ras Laffan and as lead underwriter on the Ras Laffan bond offering.

IMPLICATIONS, SUGGESTIONS AND RECOMMENDATIONS [SLIDE 13]

LNG AND OTHER GAS RELATED PROJECTS

- The establishment of a Comprehensive Financing Strategy/Plan at the earliest possible stage in the development of a project will have a significant and positive impact on the ultimate financing.
- A project Finance Team must work closely with and have 'Buy-In' from the broader project Development Team.
- Establishing a 'competitive framework' for the financing is critical (working seriously with more than one market or funding source; taking advantage of the obvious influence of contractors and vendors).
- Efficiency of execution of a project financing will be enhanced by the establishment at an early date of a reasonable set of 'Standard Financing Conditions'.
- Early discussions and negotiations (including fee negotiations) with commercial banks and ECAs should contemplate a Bond offering.
- The key to achieving the desired credit ratings is education, preparation and rehearsal.
- Credit ratings which exceed the 'sovereign ceiling' are more likely with export oriented projects which will have dollar denominated revenue flows.

IMPLICATIONS, SUGGESTIONS AND RECOMMENDATIONS (CONT.)

LNG AND OTHER GAS RELATED PROJECTS

[SLIDE 14]

- There is no reason to believe that \$1.2 Billion is the maximum amount of bond financing that a project issuer could do. Over the course of 12 to 18 months a high quality project should be able to raise well in excess of \$2.0 Billion in the Capital Markets.
- The Capital markets are much less concerned about political/regional risk and volatility in the Middle East than many people had expected.
- Going forward, Capital Markets financing will complement but will not replace Bank/ECA financing for major international projects. There are numerous economic as well as non-economic reasons why Banks and ECAs will always be important for the success of projects.
- Depth of market (size), long maturities, ease of execution and attractive pricing establishes Capital Markets financing as a critical element of the Finance Plan for any high quality project in the emerging markets.



“Middle East Gas : Prospects & Challenges”

Session (10)

Economic and Financing Challenges

Paper No. (10-2)

The Export-Import Bank of Japan and LNG Development Projects

**Mr. Koichi Fujii
Director General,
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J-EXIM
JAPAN**

The Export-Import Bank of Japan and LNG Development Projects

**Koichi Fujii
Director General
Project and Corporate Analysis Department
The Export-Import Bank of Japan**

Summary

The Export-Import Bank of Japan, established in 1950, is wholly owned by Japanese government. The objective of the bank's establishment is to promote Japan's economic interchange with foreign countries. Now the bank has about US\$ 88 billion equivalent asset. In collaboration with the oil/gas producing countries on their development programs and projects, the bank has achieved considerable business record. To begin with LNG projects, the bank has been involved in other gas related projects such as methanol, direct reduction iron, fertilizer, petrochemical complex, pipelines and power plants. The bank also supports infrastructure development in oil/gas producing countries. Policy dialogue between the bank and host government is indispensable.

THE EXPORT-IMPORT BANK OF JAPAN AND LNG DEVELOPMENT PROJECTS

SECOND DOHA CONFERENCE
ON NATURAL GAS

"Middle East Gas: Prospects & Challenges"

March 17 - 19, 1997 Doha, Qatar

Koichi Fujii
Director General
Project and Corporate Analysis Department



The Export-Import Bank of Japan

The outline of The Export-Import Bank of Japan

1. status

a wholly government owned bank established in 1950

2. objective

to promote Japan's economic interchange with foreign countries (Law Article 1)

3. conditions for financing

co-finance, in principle, with commercial banks and/or other financial institutions,
commercial viability to secure scheduled repayment

4. total assets (as of March 31, 1996)

US\$ 87,987 million equivalent

5. capital (as of March 31, 1996)

US\$ 9,227 million equivalent

to be continued



The Export-Import Bank of Japan

The outline of The Export-Import Bank of Japan

6. full lineup of financial products

export credit : **EC**

import credit : **IC**

overseas investment credit : **OIC**

untied loan : **UL**

public bond purchase

bridge loan

guarantee

equity participation

7. terms and conditions

8. currency

9. Project Finance



The Export-Import Bank of Japan

Collaboration
with the Oil/Gas Producing Countries
on their Development Programs and Projects
purposes

stable supply of energy resources both to Japan and
Asian region

further industrialization and sustained growth of
the Oil/Gas producing countries

effects

financing the project

financing project related infrastructure

technology transfer

environment protection

to be continued



The Export-Import Bank of Japan

Collaboration
with the Oil/Gas Producing Countries
on their Development Programs and Projects

business record other than oil production

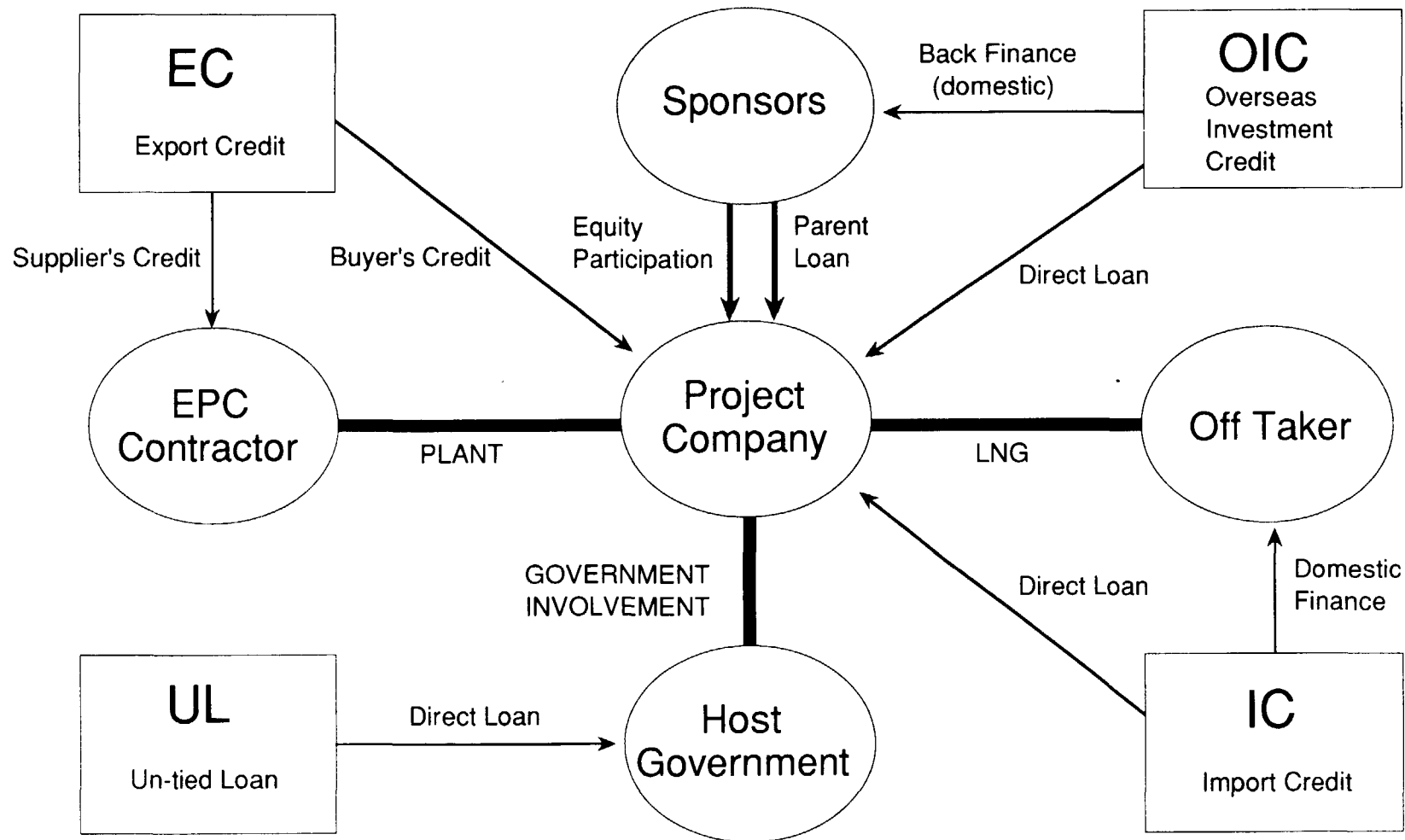
LNG project	: Qatar, Abu Dhabi, Brunei, Malaysia, Indonesia, Australia
Methanol project	: Saudi Arabia, Venezuela, Indonesia
Direct reduction iron	: Qatar, Egypt
Fertilizer plant	: Indonesia, Malaysia
Petrochemical complex	: Indonesia, Thailand, Malaysia, Venezuela, Mexico
Pipeline project	: Malaysia, Colombia, Mexico
Power station	: Thailand, Indonesia, Malaysia, Colombia, Mexico



The Export-Import Bank of Japan

LNG-1

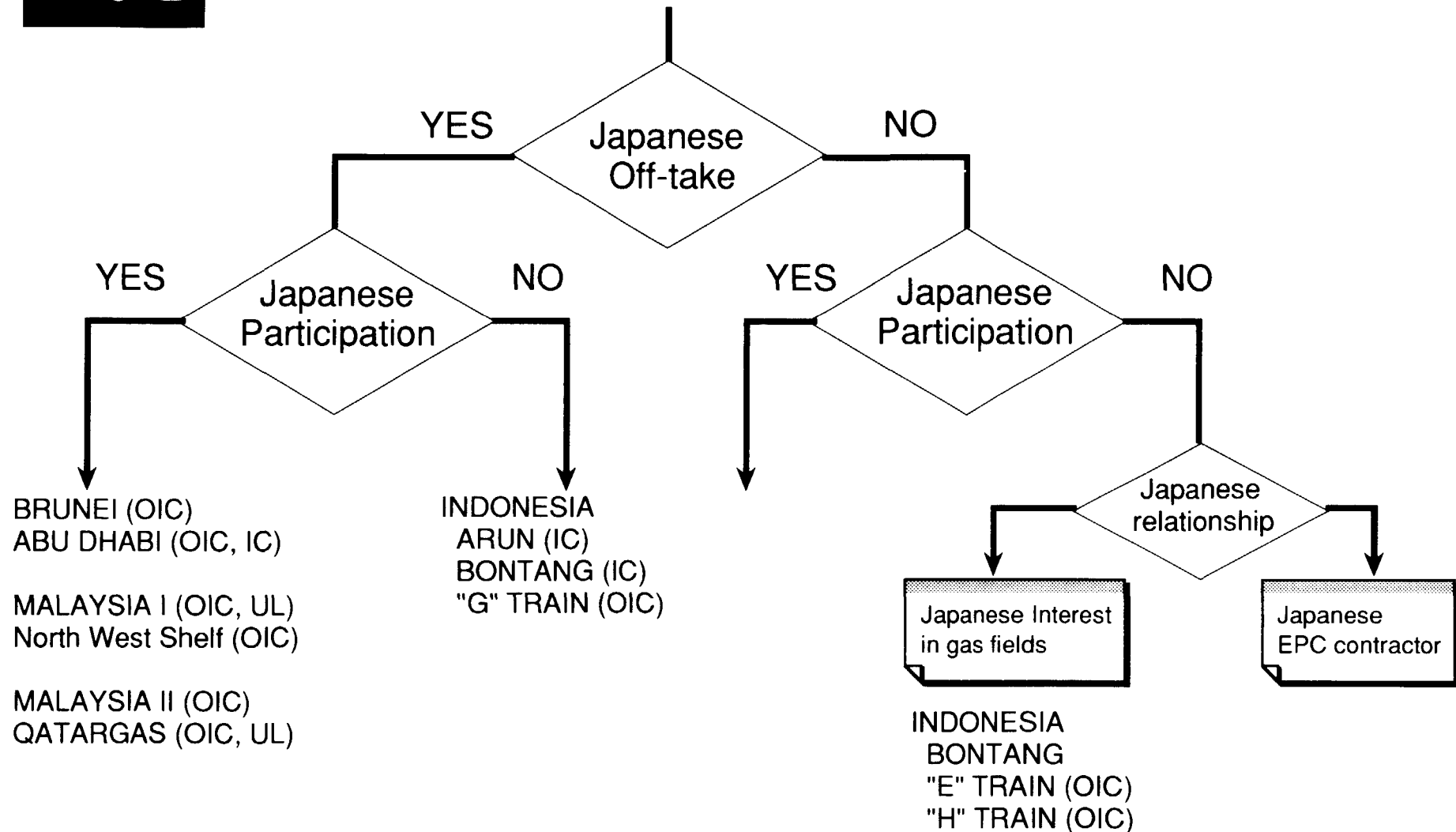
JEXIM's LNG support tools (EC, OIC, IC & UL)



The Export-Import Bank of Japan

LNG-2

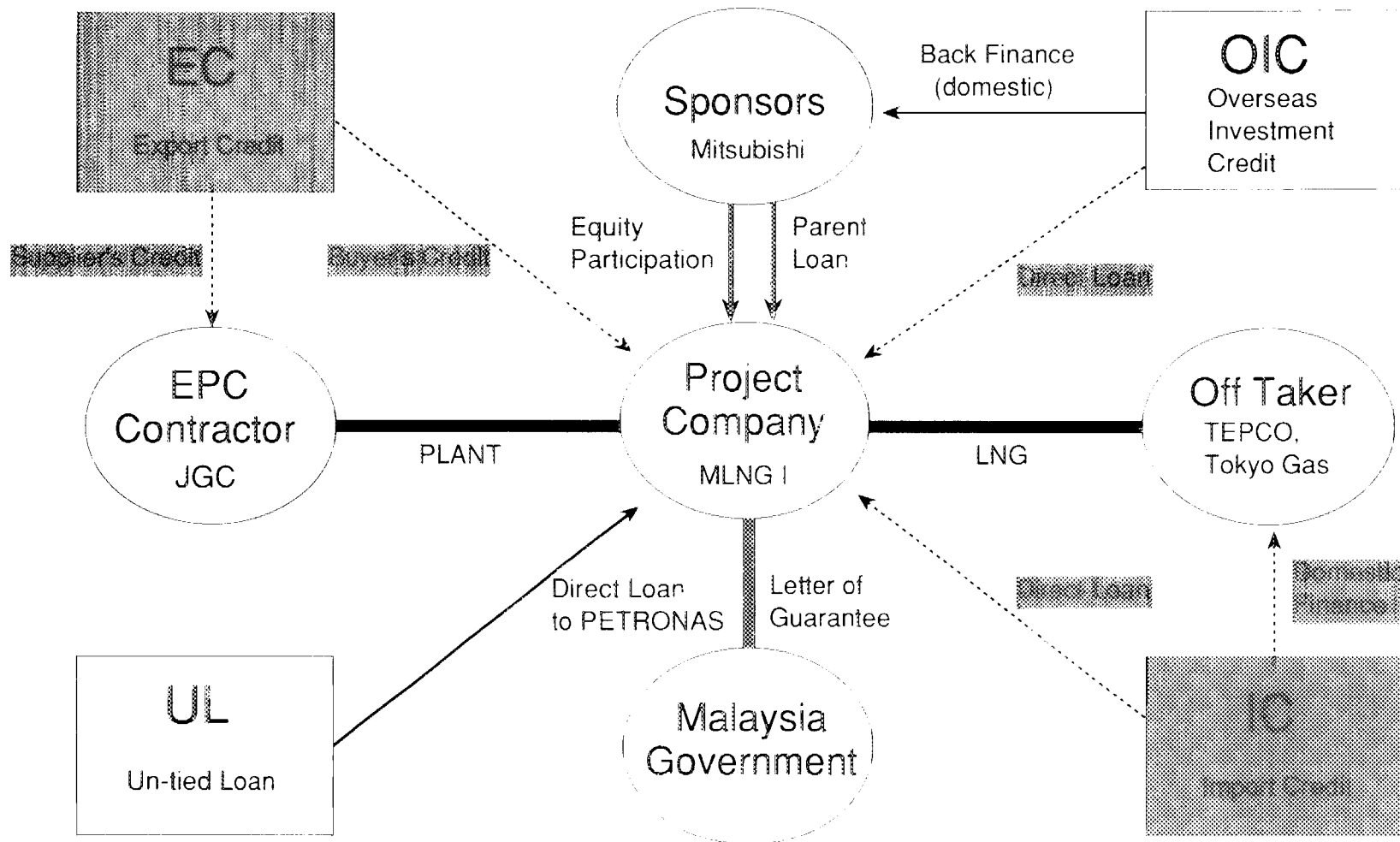
Japanese ties in JEXIM's LNG Finance



The Export-Import Bank of Japan

LNG-3

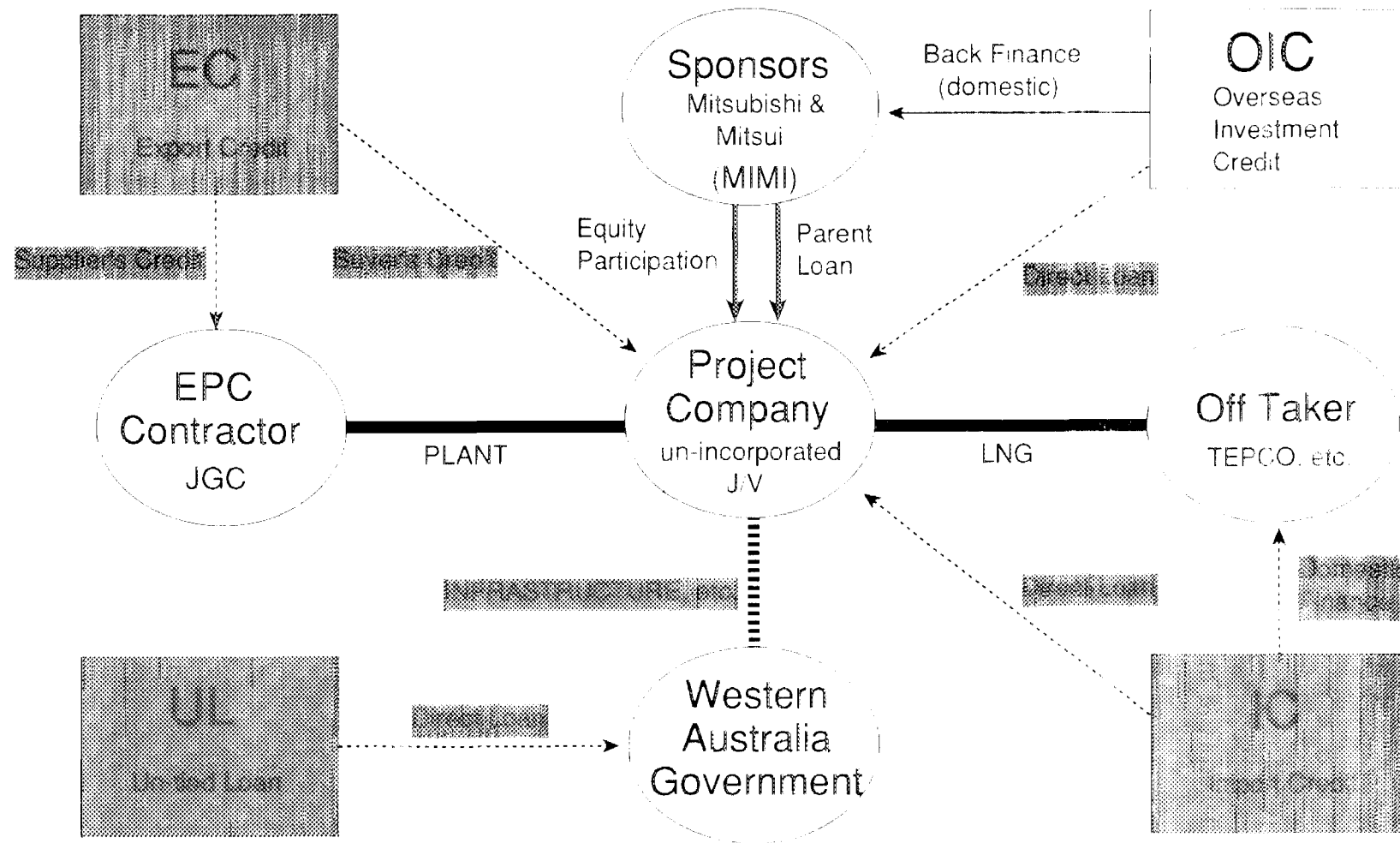
MALAYSIA LNG I



The Export-Import Bank of Japan

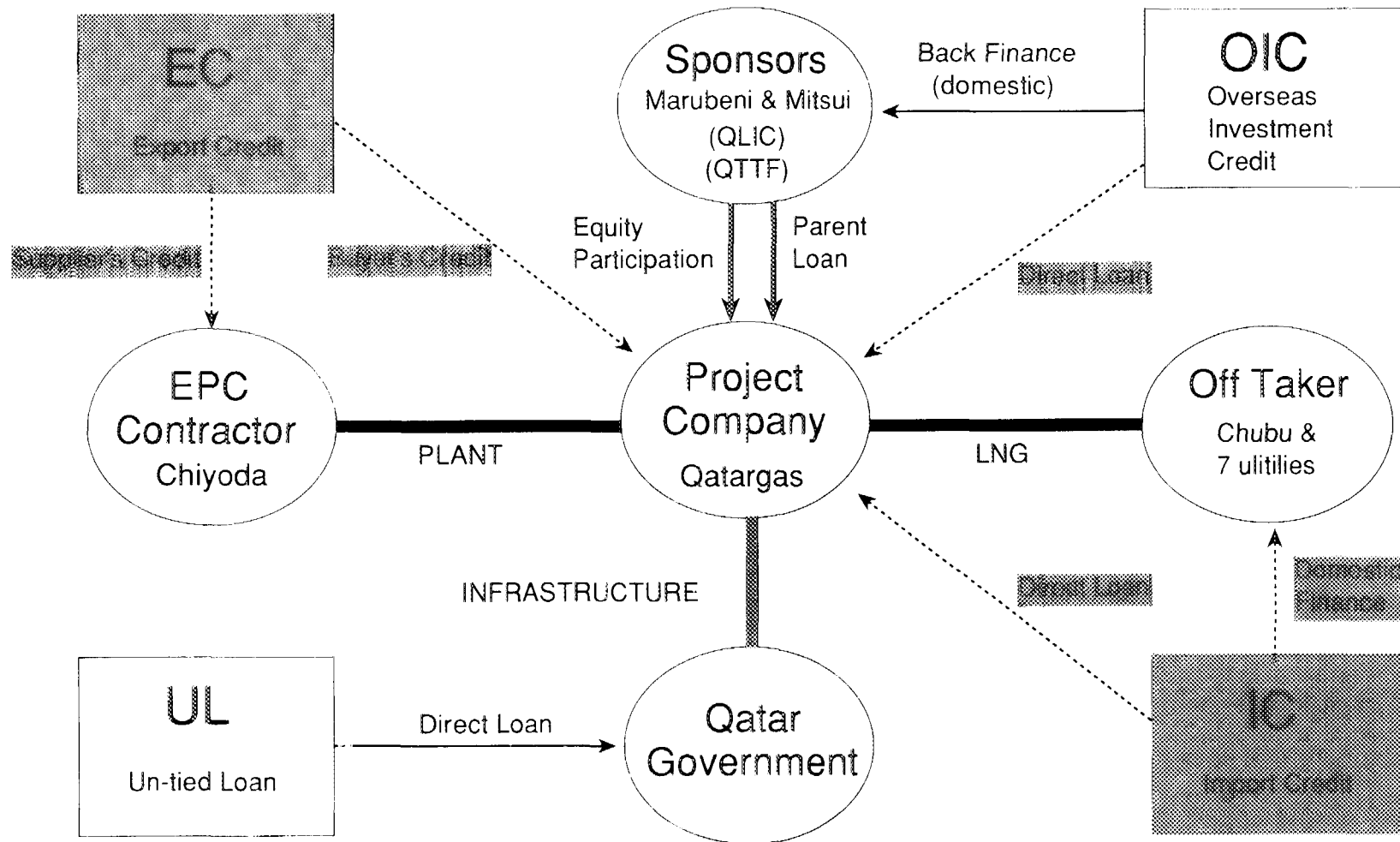
LNG-4

North West Shelf LNG



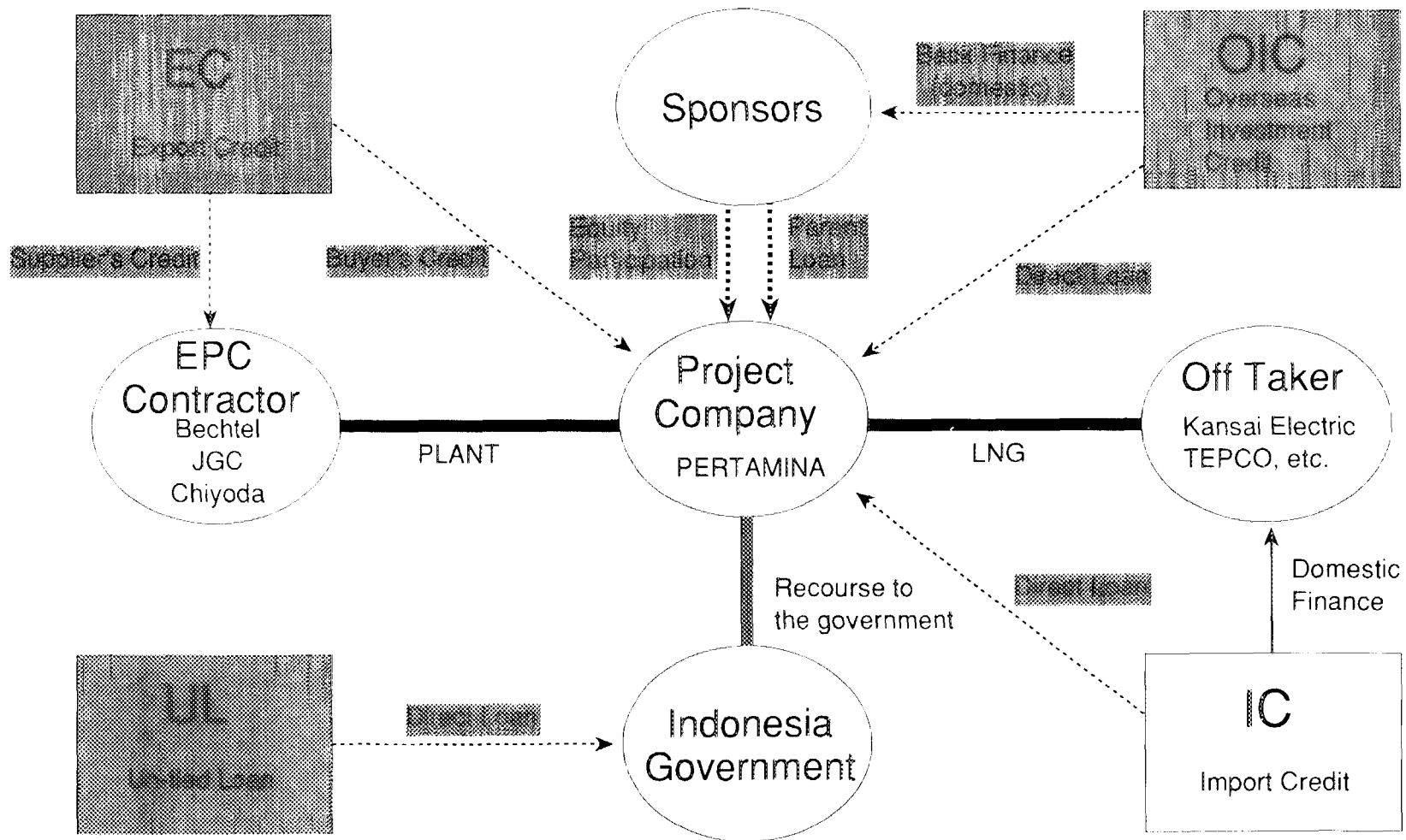
The Export-Import Bank of Japan

QATARGAS LNG



LNG-6

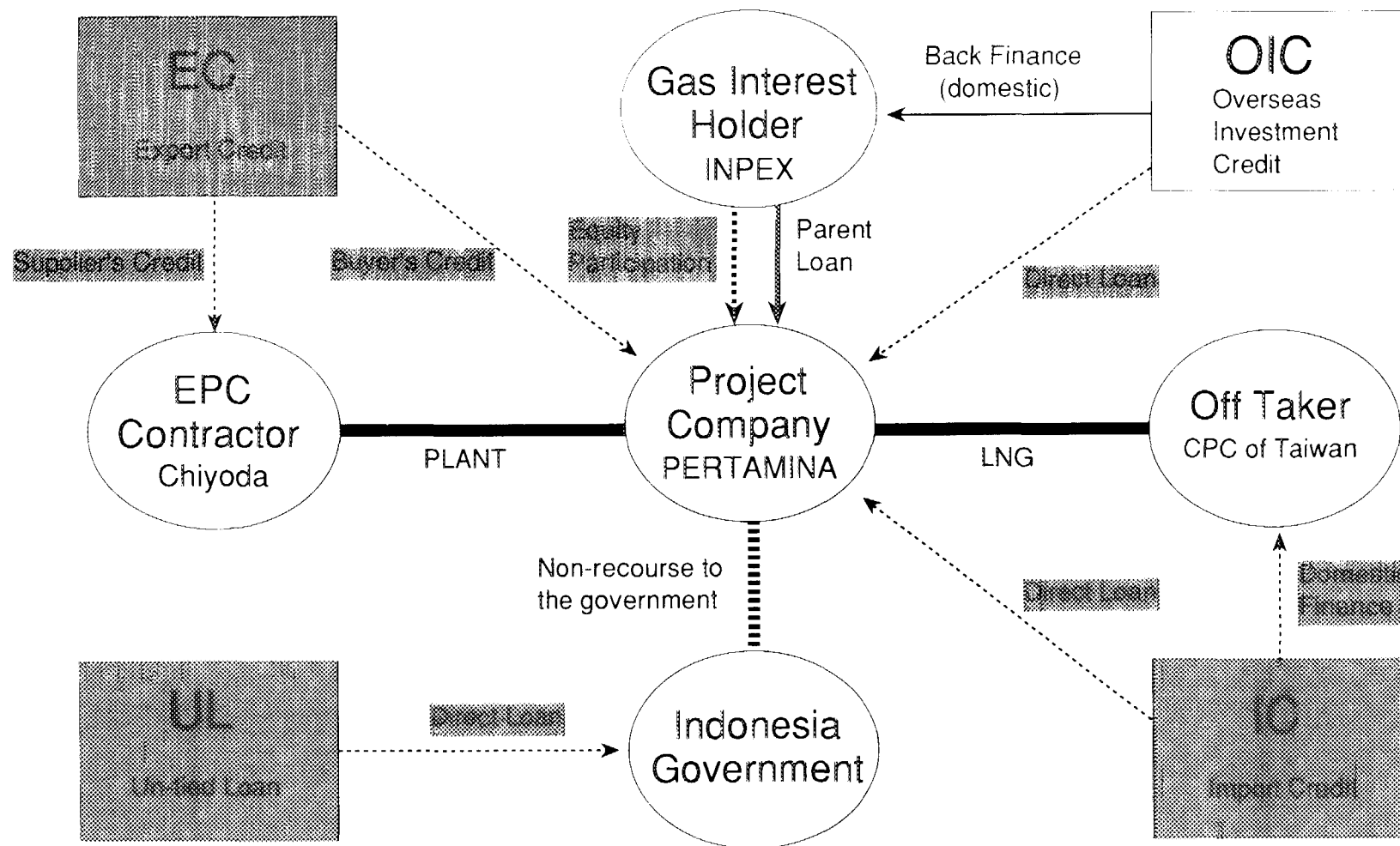
INDONESIA ARUN / BONTANG



The Export-Import Bank of Japan

LNG-7

INDONESIA BONTANG "E" TRAIN



The Export-Import Bank of Japan

Conclusion

JEXIM further continues extending strong financial support to the development program of the Oil/Gas producing countries taking each country's policy into consideration.



The Export-Import Bank of Japan



“Middle East Gas : Prospects & Challenges”

Session (10)

Economic and Financing Challenges

Paper No. (10-3)

Financing LNG Projects

Jean O. Facon

Managing Director, JP Morgan

U.K.



“Middle East Gas : Prospects & Challenges”

Session (10)

Economic and Financing Challenges

Paper No. (10-4)

Financing LNG Projects

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“Middle East Gas : Prospects & Challenges”

Session (10)

Economic and Financing Challenges

Paper No. (10-5)

Financing LNG Projects

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SECOND DOHA CONFERENCE ON NATURAL GAS

"MIDDLE EAST GAS : PROSPECTS AND CHALLENGES"

SESSION 10 : ECONOMIC AND FINANCING CHALLENGES

(PANEL DISCUSSION : FINANCING LNG PROJECTS)

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INTRODUCTION

Relatively high costs (capital and transportation) implies long term commitments by all parties and economic incentives from Host Governments. Lenders and investors in financings for such projects will be looking at the overall chain and seeing where the economics are being justified. This will mean developing the capacity to incorporate multi-financing packages from many different institutions into a coherent financing package. The challenge for lenders will be having the ability to assess the risks in a multi-linked financing and also to have the ability to tap many different financial markets at the same time.

COMMENTS SUMMARY

Perhaps I should commence by referring to the words of Mr. Bogarty of Mobil - two years ago when he said that perhaps the future of LNG financing lies, inter alia, in going further downstream for credit support and also by tapping the capital markets. The second avenue we have just seen with the success of the Ras Laffan LNG bond issue. The first and most crucial avenue has yet to my mind to be fully explored.

My belief is that there will be a very rapid consolidation in the LNG (and in fact gas) and power fields. This is for very simple reasons :

- a) Capital needs enormous for the chain
- b) Ability to provide capital
- c) long term investors and delayed but eventually stable rates of return
- d) Increasing privatisations and IPPs as end buyers of power - higher credit risk
- e) Rise of merchant power leads to necessity to have stable costs
- f) Fuel mismatch risk
- g) Power generation, transmission and distribution "conglomerates"
- h) Majors in oil and gas looking to develop and utilize their resources
- i) LNG "expensive" for medium to long haul routes in a moderate oil price environment - is this consistent with the aims of "privatizing governments" who wish their power system to be more efficient and lower cost ?

This leads to the question -where will the capital come from ?

Large equity needs can be met from two main sources

A. Sponsors with deep pockets and long term strategic aims. Who can this be ? Maybe major oil and gas companies and global power entities - after all we are only talking about supplying BTU's in one form or another - and/or joint ventures involving both.

B. Governments with the ability to wait for a real return and hence "facilitate" the developments in their respective countries. This form of "facilitation" could take many forms .

Debt can be met from a variety of sources - capital markets, private placements, bank , Export Credit, Multilaterals , Government supported programs

Inevitably there will be recourse to project finance for a large part of these debt facilities - because it eases the pressure on the capital of the sponsors and because it provides a useful check of the viability of the project.

The challenges will be for the various parties to come to grips with

- Multi Government involvement
- Multi institutional involvement
- Sponsors who are involved in more than one link in the chain
- Coordination of funding sources
- Multiplicity of end buyers of power
- Intercreditor issues
- Regional risks
- Implicit governmental supports and not explicit
- The economics and technical aspects of the total chain

In terms of debt finance I believe that Banks will continue to have a very significant role to play - because they have a tendency to be still around when capital markets are not. Their balance sheets are going to be needed as well as their expertise in structuring project finance.



“Middle East Gas : Prospects & Challenges”

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Paper No. (10-6)

The Role of Regional Financial Institutions in Financing Future LNG Projects in the Gulf

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**The Role of Regional Financial Institutions
in Financing Future LNG Projects
in the Gulf**

By

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ABSTRACT

Compared to present LNG projects in the Gulf, raising financing for new projects to come would be considerably more challenging. The competition between LNG suppliers is increasing. As a result, suppliers are extending easier terms of LNG sales to traditional buyers. Meanwhile, they are exploring new buyers, who may not enjoy the same top credit ratings of current buyers. These factors, however, are among the essential considerations of LNG financing, upon which commercial banks and export credit agencies extend their financing commitments. Accordingly, the extent of such commitments would probably be negatively affected. Therefore, creativity in structuring new LNG financing, and maximizing different sources of funds are definitely called for now more than ever.

Perhaps the natural source of funds to be increased is the Gulf market itself. The potential is great as resources still remain under exploited in the LNG sector. Regional financial institutions have been able in recent years to maximize loan funds raised for projects in the area. This is attributed to their ability to read the market, and cater to its requirements, when they were entrusted with leading roles in structuring and arranging large loan facilities for major petrochemical and heavy industrial projects in the Gulf. This ability, coupled with the understanding of the sensitivities and priorities of Gulf national oil companies - the main sponsors of LNG projects - could be perfectly employed for the success of LNG financing. So far, only few regional financial institutions have assumed senior roles in advising, coordinating and structuring LNG financings. However, the time may be appropriate now for this to change and give the opportunity to these institutions to lead future LNG financings in support of the Gulf LNG industry.

1. The First Wave of LNG Projects in the Gulf

Up to the first quarter of 1997, 4 LNG projects in the Gulf have shaped up and are in various phases of operation and / or implementation. These projects are (in chronological order) Adgas, Qatargas, Rasgas and Oman LNG. Each of these is briefly described hereunder.

a) Abu Dhabi Gas Liquefaction Company Ltd. (ADGAS)

Adgas is a joint venture between Abu Dhabi National Oil Company (ADNOC), BP, Total, Mitsui and Mitsui Liquefied Gas. The company receives associated gas from the offshore oil fields of Umm Shaif, Zakum and Al Bunduq. The two train complex on Das Island currently produces 2.3 million ton per annum (MMTPA) of LNG in addition to LPG. The LNG is sold under a long term contract to the Tokyo Electric Power Company Inc. (TEPCO). The complex has been in operation since 1977. Adgas expanded its operation by building a third LNG train with a capacity of 2.3 MMTPA; it started production in 1994.

b) Qatar Liquefied Natural Gas Company Ltd. (Qatargas)

Qatargas is the first LNG project to exploit the vast non-associated gas reserves of Qatar's North field. The project is developed by two interrelated companies. Qatargas Upstream develops a concession in the North field and separates the gas from the condensates; and Qatargas Downstream handles the liquefaction of gas and exports of LNG. Both companies are joint ventures between Qatar General Petroleum Corporation (QGPC), Total, Mobil, Mitsui and Marubeni. The complex is located at Ras Laffan. it started production and exports of condensates in the last quarter of 1996; and LNG exports are scheduled to commence in February 1997 from the Ras Laffan Port. At this stage, two LNG trains, which production capacity is 4 MMTPA, will be in operation. Chubu, a Japanese utility company, will buy the LNG under a long term contract. A third LNG train with a capacity of 2 MMTPA is currently under construction. The production of this train will be also directed to Japan as of 1999.

c) Ras Laffan Liquefied Natural Gas Company Ltd. (Rasgas)

Rasgas is the second LNG venture in Qatar, after Qatargas. It is also based on the gas reserves of the North field. The QGPC and Mobil joint venture is developing both upstream and downstream operations. In December 1996, Itochu and Nissho Iwai - the Japanese trade houses - signed heads of agreement in anticipation for becoming shareholders in the company. Rasgas will have a production capacity of 5 MMTPA from 2 LNG trains. Korean Gas Corporation (KGC) has entered into a long term contract with Rasgas for the purchase of 2.4 MMTPA starting 1999. A number of potential buyers are under consideration to purchase the balance.

d) Oman LNG Llc.

Oman LNG is a joint venture between the Government of Oman, Shell, Total, Partex, Mitsubishi, Mitsui and Itochu. The company will develop the downstream part of the Oman LNG project. Liquefaction and exports of up to 6.2 MMTPA of LNG will start in 2000. KGC signed a sales contract with the company for 4 MMTPA. PTT, Thailand also signed heads of terms with the company for the sale of a further 2 MMTPA of LNG. The gas will be produced from the recently discovered Barik, Saih Rawl and Saih Nihayda non-associated onshore gas fields.

2. Features of LNG Projects

There is a number of established features of LNG projects, which are instrumental to their success. The most important of these feature are:

- ample proven gas reserves;
- creditworthy sponsors with successful track records in building and operating LNG projects;
- strong government share holding and support;
- a gas price formula that helps the project economics; and
- first rate contractors entrusted with the complexity of the job through fixed price lump sum turn key contracts.

Clearly, all the above features are stemmed from the host country (i.e. the gas producing country) and the project sponsors. What about the buyer and the buyer's country? Those have several obligations which are also required to guarantee the project's fruition; this include:

- building first class receiving and regasification facilities;
- committing to take or pay the LNG for long periods;
- committing, in many cases, to an LNG floor price that supports project economics; and
- availing a strong government support to the scheme.

In addition to the above a dedicated LNG tankers fleet is required for each project. The cost of these tankers is significant (approximately US\$ 250 million each). The responsibility of funding, building and operating LNG tankers is usually negotiated and agreed upon between the buyer and seller at an early stage.

3. The Pillars of LNG Project Financing

The commitments and obligations to the project, whether came from LNG buyers or sellers, were the basis of structuring financing that worked. The main pillars of such financing were:

- completion guarantees provided by sponsors;
- significant export credit agencies' guarantees; and
- the reliability on the credit worthiness of the LNG buyers, typically AAA or AA rated, to honour their take or pay and receivables obligations over the life of the sales contract (usually much longer in tenor than the financing).

4. Characteristics of LNG Project Financing in the Gulf

The financing of LNG projects in the Gulf, whilst concluded within the guide lines mentioned above, each had its own characteristics as briefed below.

a) Adgas

As the pioneer LNG project in the Gulf, the shareholders of Adgas had to finance the project until completion and during first years of operation. At that time, in the early 70's, it would have been difficult to do otherwise due to the relative newness of project financing worldwide, and in the Gulf in particular. Worth mentioning that the upstream operations is not part of Adgas operations. In 1983, a financing package was put together to fund an LNG storage facility. This US\$ 500 million financing was fully guaranteed by the shareholders. The third train was also financed by the shareholders.

b) Qatargas

The two financing of Qatargas were the first in which lenders accepted the risks of an LNG project, against proper security, assurances and guarantees. The Qatargas Upstream US\$ 570 million financing was concluded in December 1996. Banks extended credit against projected cash flow from sale of condensates. The loan comprised 3 main tranches: an export credit guaranteed tranche; a tranche to the State; and a commercial tranche.

The Qatargas Downstream financing was a Japanese affair altogether. Japan Exim guaranteed US\$ 2 billion, against which banks lent in 1995. The strong Japanese presence was to support Japan's strategic LNG imports from the area and exports of Japanese services and equipment (Chiyoda was the general contractor). The project will repay its debt from future sales of LNG. Qatargas shareholders guaranteed completion of both Upstream and Downstream financing.

The third train was financed mainly by the shareholders in addition to a loan from Japan Exim to QGPC.

c) Rasgas

This is the largest and most aggressive LNG project financing so far. It will probably become a classic case for a successful large scale financing world wide. The US\$ 2550 million package was signed in December 1996. It comprises a US\$ 1200 million 144 A bond issue and a US\$ 1350 million debt financing. The latter is composed of US\$ 450 million commercial loan and 3 loans in the aggregate amount of US\$ 900 million, guaranteed by US Exim, SACE and ECGD. The funds are to finance both the upstream and downstream operations. The debt will be repaid from projected revenues of condensates and LNG. As with Qatargas, shareholders guarantee project completion. The bonds were the first ever project related bonds in the region and the first ever LNG project bonds internationally.

d) Oman LNG

Similar to Adgas, Oman LNG concentrates on the downstream only. The US\$ 2000 million financing depends on the sales of LNG for repayment. The financial closing is scheduled for mid 1997. A significant part of the financing is expected to be covered by export credit guarantees. There is no floor price in Oman LNG's sales contract with KGC. The lenders will either have to accept the risk of market price fluctuations, or other means of cash flow support from the sponsors, or a combination of both.

5. The Role Played by Regional Financial Institutions

Among regional financial institutions and banks, only Pan-Arab and Pan-Gulf institutions were active in arranging and underwriting LNG financing. The table below shows the involvement of regional institutions in Gulf LNG project financing at various senior roles:

	Adgas		Qatargas Upstream		Qatargas Downstream		Rasgas		Oman LNG	
	Reg.	Intl.	Reg.	Intl.	Reg.	Intl.	Reg.	Intl.	Reg.	Intl.
Advisors	1 ^(a)	-	-	1	-	1	-	1	-	1
Coordinators ^(b)	3	1	1	3	-	2	-	2 ^(c)	-	3
Arrangers	5	7	3	6	-	4	1	7	1	6
Underwriters	5	7	3	6	-	4	3	25	^(d)	^(d)

- (a) preparation of information memorandum and related advice.
- (b) this may not necessarily be a formal lenders' title; however, most of the interaction between the project company and the arrangers is handled by representatives of the arrangers who act as coordinators.
- (c) in Rasgas there were 2 coordinators/advisors for each of 4 bidding groups; none of those 8 institutions was regional.
- (d) the underwriting group for Oman LNG is still under formation but the ratio is expected to be close to that of Rasgas.

With the exception of Adgas, which was considered by many to be closer to a corporate finance rather than a project finance given the guarantees, the involvement of regional institutions was clearly low. Arab Petroleum Investments Corporation (APICORP) was active in all of the above mentioned financing (except Qatargas Downstream). Other than APICORP, only 3 regional banks assumed senior roles in one or more of the above transactions.

The host countries of the LNG projects welcomed the involvement of local and regional financial institutions and encouraged more of it. They also attached importance to the choice of experienced international institution(s) to lead the LNG financing. In the first wave of LNG projects, this decision was founded on the following:

- the triangular relationship between international banks, their clients the contractors and the export credit agencies. a catalyst in maximizing ECA guarantees;
- the previous track record in leading LNG financing internationally;
- the ability to underwrite significant amounts; and
- experience in international capital markets.

On the participation front, it is still difficult to formulate a conclusion with regard to the appetite of Gulf banks to participate in LNG financing. The reference points are not enough since only Qatargas Upstream financing was syndicated in the Gulf. That said, whilst LNG financing structures were well received internationally, they do not appear to cater for the needs and preferences of Gulf banks. The following hurdles ought to be taken into consideration should an LNG financing be syndicated in the Gulf:

- little appetite for cross border financing;
- concentration on retail business;
- relative small size of many Gulf banks;
- complexity of the financing which requires considerable commitment from the already scarce human resources in project finance; and
- preference to lend short term.

6. Arab Petroleum Investments Corporation (APICORP)

APICORP is an Arab joint-stock company established in 1975 in accordance with an international agreement signed and ratified by the governments of ten member states of the Organization of Arab Petroleum Exporting Countries (OAPEC). The share capital is owned by the governments of United Arab Emirates, Bahrain, Algeria, Saudi Arabia, Syria, Iraq, Qatar, Kuwait, Libya and Egypt. The paid in capital of APICORP is US\$ 460 million; and the total assets as at 30/6/1996 amounted to US\$ 1389 million, of which the loan portfolio reached US\$ 568 million.

The prime objective of APICORP is the financing of petroleum projects and related industries. This includes oil, gas and petrochemical sectors and ancillary activities. APICORP is the only regional financial institution specializing in the hydrocarbon based industries.

Since inception, APICORP realized the potential and importance of the LNG industry to Arab gas producing countries. It has been particularly active therefore in supporting this industry. APICORP has been involved, at senior levels, in the financing of LNG projects in Algeria, Abu-Dhabi (Adgas), Qatar (Qatargas Upstream and Rasgas) and Oman (Oman LNG). In the most recent LNG financing, the US\$ 1350 million for Rasgas, APICORP was a member in a group of 7 arrangers & underwriters mandated to raise the loans. APICORP was responsible for regional coordination in view of its experience in the industry and knowledge of the Gulf market.

7. The Changing Nature of Future LNG Projects in the Gulf

Over the last few years the competition between LNG suppliers world wide to secure markets for their product has surfaced. This suggests a move towards a buyer's market from a demand/supply point of view. Whether or not this will continue depends on the actual growth of demand and the rate of realization of LNG projects under consideration. Market projections are covered at length by other papers presented in this Conference.

With regard to Gulf LNG producers, demand and supply projections suggest strong competition from the traditional suppliers (Indonesia, Malaysia, Brunei and Australia) in the targeted markets of Asia Pacific. It is not any easier in the European markets. These are supplied by LNG from Algeria and possibly from Egypt and Libya in the future; in addition to gas supplies from Algeria, Russia and the Netherlands.

In view of this the LNG buyers would have an opportunity to negotiate more flexible and convenient sales terms. This may include abolishing the floor price mechanism altogether (which has started already); and allowing for a wider latitude in the volume obligations.

Furthermore, a number of new potential buyers in South East Asia (Taiwan, India, Thailand and China) do not enjoy a AAA, or AA rating in the money markets as Japan and South Korea. That does not necessarily impact on the ability of these countries to honour its obligations under LNG sales agreements.

As a consequence, the export credit agencies may not extend the same level of support and guarantees as that to the first wave of LNG projects.

Financing will thus become more difficult to arrange. Both lenders and sponsors will need to examine new venues for financing to succeed packaged. This, for example, could include the following:

- the sponsors to extend their guarantees beyond completion of the project to cover certain possibilities of cash flow deficiencies during operations (either directly through cash injection or indirectly by subordinating gas costs and other royalties);
- the lenders to accept higher lending risk and higher ratio of commercial loans to export credit guaranteed loans;
- the sponsors and their advisors to explore new sources of funds to meet any shortfall in the export credit and / or commercial loan facilities, this could include for example mezzanine financing and convertible bonds; and

- to integrate the LNG project with downstream power projects in the buying market and use the revenue of the latter to generate cash flow for both; this of course would be a much more complicated financing and would require longer time to conclude.

This list is far from being exhaustive. Obviously, there is no single “clear” or “good” financing structure for future LNG projects. It could very well be a combination of all the possibilities mentioned above.

8. The Value Added of Regional Financial Institutions in Arranging Future LNG Project Financings in the Gulf

The Gulf dimension in financing new LNG projects will be very important. Based on the explanation given above, it will be essential to pull together all available sources of funds and maximize those which have potential to increase. One would probably start by targeting Gulf banks and money markets. These are considered the natural source for raising financing for projects in the Gulf.

Gulf banks and financial institutions proved they could be relied upon in supporting the financing of major projects in their countries. The Equate US\$ 1.2 billion loan in Kuwait, the Saudi Petrochemical Company (SADAF) US\$ 700 million loan in Saudi Arabia and the Qatar Petrochemical Company (QAPCO) US\$ 200 million loan in Qatar were recent successful examples for that. The common factor in these financing is the harmonious cooperation between regional and international financial institutions to arrange the loans at the top level (i.e. advising, coordinating and structuring the loan with the borrower).

Perhaps the same formula could be applied in LNG projects to come. Complementing the financing arrangements with this Gulf dimension talked about, at a senior level, would no doubt be beneficial in many ways including:

- having been financing partners to the national oil companies (who are the LNG project sponsors) for a long time, regional financial institutions could best understand the requirements and sensitivities of the host country; and with that, reach a balanced financing structure acceptable to the parties involved;
- structuring the financing, or tranches thereof, to suit the requirements of Gulf banks; this tailor made structure could possibly contribute to maximizing the participation from the region; and
- exploring the regional capital markets which could be an important source of funds.

CONCLUSION

The next generation of LNG projects in the Gulf may not necessarily enjoy all the features that facilitated raising the financing for existing projects. Creativity in financing these projects, therefore, has never been more important in order to maximize the different sources of funds.

The natural source of financing, which is also under exploited still, is the Gulf money and capital market. A thorough understanding of this market is, therefore, essential at the structuring phase of the LNG financing in order to attract funding from this market. The involvement of regional financial institutions in arranging the LNG financing at senior levels would ensure that the requirements of potential Gulf providers of funds would be addressed and fitted, as much as practical, in the financing structure.

Furthermore, the excellent long established relationships that regional financial institutions enjoy with national sponsors of LNG projects, and their comprehension and appreciation of the latter's priorities, would contribute to reaching a financing structure acceptable to the different parties.

Gulf countries have established and invested in regional financial institutions and banks. These vehicles have become an integral element, as well as a catalyst, to growth and development. It is now the time to draw upon regional financial institutions to demonstrate their ability to support building the LNG sector.

Such a step forward would lay the foundation for a stronger and more momentous support in envisaging and realizing Gulf LNG projects in a future short to come.

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The opinions expressed and the conclusions reached in this paper
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Paper No. (10-7)

Financing LNG Projects

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