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ASSESSMENT OF COSTS AND BENEFITS OF FLEXIBLE AND ALTERNATIVE FUEL USE IN THE U.S. TRANSPORTATION SECTOR

TECHNICAL REPORT NINE:

DEVELOPMENT COSTS OF UNDEVELOPED NONASSOCIATED GAS RESERVES IN SELECTED COUNTRIES

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DISCLAIMER

This report is based on a study prepared for the Department of Energy by Energy and Environmental Analysis, Inc., of Arlington, Virginia.

CONTENTS

TABLES

FIGURES

EXECUTIVE SUMMARY

Introduction

As part of its Alternative Fuels Assessment, the U.S. Department of Energy (DOE) is studying the use of compressed natural gas (CNG), methanol, and other derivatives of natural gas as alternative transportation fuels. One part of this study is determining the cost and most likely sources of new, uncommitted natural gas supply. The largest sources of natural gas are outside the United States. Remaining reserves of natural gas in the United States, excluding about 25 trillion cubic feet (tcf) on the North Slope of Alaska, are about 166 tcf (Oil and Gas Journal Worldwide Report 1990), which represents approximately 4 percent of the world's proved reserves.

Foreign sources of natural gas could have a direct impact on the United States by providing a feedstock for methanol or liquefied natural gas (LNG) and an indirect impact by displacing oil use in other countries, thus altering the economics of world oil trade. Although natural gas is currently traded internationally on a more limited basis than petroleum, this analysis is conducted on the premise that a world natural gas market is likely to emerge over the next two decades through new pipelines and expanded trade of LNG and methanol produced from natural gas. Furthermore, in each region, natural gas and petroleum products substitute for one another. Substitution between gas and residual fuel in boiler-fuel markets and substitution between methanol or CNG and gasoline in motor-fuel markets will strengthen the links between oil and gas price movements.

These market relationships are characterized in a formal way by the Alternative Fuels Trade Model (AFTM). Using estimated price-quantity supply curves for natural gas in each major gas-producing country or region as inputs, the AFTM constructs an aggregate gas supply curve.

The AFTM focuses on the production and consumption of alternative transportation fuels as substitutes for motor gasoline and diesel fuel. The AFTM determines prices and quantities that balance the interrelated world oil and gas markets. A critical modeling issue relates to the extent of market power held by the major oil-exporting nations and the manner in which such market power may be exercised. The AFTM model is sufficiently flexible to allow for the calculation of market balances under a variety of alternative characterizations of the world oil market. It characterizes market balances, or equilibria, in a selected year for multiple fuels that derive from oil or gas. The model is being used to examine the alternative fuels in a multifuel scenario. The supplies of the two principal raw materials (crude oil and natural gas) are represented by upward-sloping price-responsive curves. The model provides for fuel transportation between regions and includes processes that convert crude oil or natural gas to industrial and consumer fuels. The AFTM models the final demand for each fuel by downward-sloping constant-elasticity demand curves. It provides opportunities for long-run fuel substitution in flexible-fuel vehicles and industrial and utility boilers. The degree of fuel switching by flexible-fuel vehicles influences the market penetration and success of alternative transportation fuels, such as methanol or CNG. Substitution between oil and gas in the industrial-utility boiler-fuel market establishes an important connection between the prices of petroleum products and gas-based products.

The AFTM provides insights into the market effects of introducing alternative transportation fuels. It estimates changes in the prices, supplies, and demands of conventional fuels. It reports the levels of alternative-fuel use and tracks the geographic sources of U.S. energy supplies. The economic costs and benefits of introducing these substitute fuels are also measured, based on a standard social surplus analysis. Net benefit is estimated as the benefits that consumers gain from their levels of final demand, minus all the costs of fuel production, transportation, and conversion.

Objectives

The primary objective of this report is to provide estimates of volumes and development costs of known nonassociated gas reserves in selected, potentially important supplier nations, using a standard set of costing algorithms and conventions. Estimates of undeveloped nonassociated gas reserves and the cost of drilling development wells, production equipment, gas processing facilities, and pipeline construction are made at the individual field level. A discounted cash-flow model of production, investment, and expenses is used to estimate the present value cost of developing each field on a per-thousand-cubic-foot (Mcf) basis. These gas resource cost estimates for individual accumulations (that is, fields or groups of fields) then were aggregated into country-specific price-quantity curves. These curves represent the cost of developing and transporting natural gas to an export point suitable for tanker shipments or to a junction with a transmission line. The additional costs of LNG or methanol conversion are not included. A brief summary of the cost of conversion to methanol and transportation to the United States is contained in Appendix D: Implications of Gas Development Costs for Methanol Conversion.

Undeveloped nonassociated gas is the subject of this investigation because it is the most likely source of very large, new supplies of gas that could be made available for world trade in the immediate and near terms. Nonassociated gas is gas produced from reservoirs with no crude oil reserves. Definitions of what is oil and what is condensate may become somewhat subjective when dealing with high gravity liquids production. Some reports refer to gas and/or gas-condensate reservoirs. This report considers all gas contained in reservoirs in which all the hydrocarbons are in the gaseous state at original reservoir conditions. Condensate yields at the field separator may vary from virtually nothing to more than 100 barrels per million cubic feet (100 bbl/MMcf) of gas. Natural gas liquid yields after processing also vary from less than 1 percent of the raw gas flowstream to more than 14 percent.

Many countries still have underutilized associated-dissolved gas production (gas in solution in the crude oil that is released at separator conditions). However, production of associated-dissolved gas is directly related to oil production and will vary with oil production rates. Per-well associated-dissolved gas production volumes are small compared with nonassociated gas wells and are driven by the economics of the well's oil production. For these reasons, this study did not consider the potential for new sources of associated-dissolved gas production.

The following 32 countries are covered in this report:

- Abu Dhabi
- Algeria
- Argentina
- Australia
- Bangladesh
- Canada (arctic)
- Chile
- China
- Ecuador
- Egypt
- India
- Indonesia
- Iran
- Iraq
- Kuwait
- Libya
- Malaysia
- Mexico
- New Zealand
- Nigeria
- Norway (north of the 62nd parallel)
- Oman
- Pakistan
- Papua New Guinea
- Peru
- Qatar
- Russia (and the former U.S.S.R.)
- Saudi Arabia
- Trinidad and Tobago
- United Arab Emirates (U.A.E.) (excluding Abu Dhabi)
- Venezuela
- Yemen

Outline of Report

The sections of the report that follow explain the methodology and assumptions behind the analysis and discuss in more detail the reserves and cost of development in each country. The Executive Summary also contains some discussion of the sensitivities of this analysis' natural gas cost estimates to input assumptions. Section 1 outlines the approach to the study and the main sources of data. Sections 2, 3, and 4 discuss the assumptions in the estimates of reserves, investment cost, and economic analysis. Section 4 also contains some discussion of economic sensitivities. Section 5 is a country-by-country description of reserves and costs. Appendix A provides a brief discussion of the gas reserves in Angola, Bolivia, Brunei, Myanmar (Burma), Thailand, and Tunisia. Appendices B and C review concession arrangements and associated gas supply in several of the study countries. Appendix D discusses some of the implications for transportation fuel costs that may be drawn from the natural gas resource costs calculated in this report.

Summary

Natural gas reserves in 32 countries are reviewed in detail. These countries hold about 90 percent of the total proved gas reserves in the world. The nonassociated gas reserves of each country are estimated at a field-level basis, then further subdivided into that portion that is undeveloped. For this study, individual field reserves of at least 70 to 100 billion cubic feet (bcf) are used as the lower limit for inclusion in the inventory of potential developments. Estimates of development costs are made for approximately 700 fields that are expected to contain significant undeveloped nonassociated gas reserves. Table S–1 contains estimates of the undeveloped nonassociated gas in each country. Total gas reserve estimates, associated and nonassociated, developed and undeveloped, from the *Oil and Gas Journal* (OGJ) are listed in the first column for comparison. Estimates of the undeveloped nonassociated gas amount to a little more than half of the total remaining proved reserves in the countries studied.

It is useful to place the gas reserves estimates mentioned in this report in context by comparing them with the situation in the United States. The United States produced 21.0 tcf of natural gas in 1990, out of 166 tcf of reserves. After reinjected gas is accounted for, net consumption was 18.5 tcf. This yields a reserves-to-production (R/P) ratio of 9.0. The Soviet Union consumed about 29 tcf in 1990, out of 1,600 tcf of reserves. The U.S.S.R. R/P ratio was about 53.0 in 1990. The rest of the world combined (excluding the United States and the former U.S.S.R.) consumed only 31.5 tcf. The average ratio of proved gas reserves to annual production rate in the countries covered in this report in 1990 was 71. Although the United States has significant gas reserves, the United States is depleting its gas reserves at a much higher rate than the rest of the world.

The cost of development for the nonassociated undeveloped gas fields identified here varies greatly, depending on such factors as the size of the individual accumulation, the depth of the reservoir, and the location of the field. Other significant factors are the condensate yield of the reservoir, the natural gas liquid yield of the produced gas after processing, and the financial assumptions in the discounted cash-flow model used to estimate a value for the gas. A standard set of debt-equity investment financing assumptions and tax and royalty assumptions was used for every field to compare the gas resource cost in each country on an equivalent basis. Tax structures and royalty arrangements vary from country to country, and many countries have renegotiated terms for development initiated since the 1986 oil price collapse. Appendix B provides a review of the various tax and royalty schedules and production-sharing agreements with state oil companies. The gas resource costs presented here are based on the value, including return on equity, an operator of the field would expect to receive for the sale of gas, after subtracting the revenue received for condensate and gas plant liquids.

Resource cost calculations were performed for each field or group of fields likely to be developed together, with the following standard assumptions: field development takes place to maintain field production at a 1:25 ratio to initial reserves; project life (matching an LNG or methanol plant) is 15 years; total income taxes are 37.3 percent of net income; and royalties are 40 percent of gross revenue. Project financing is assumed to be 40 percent debt at 12 percent nominal interest and 60 percent equity with a nominal 20-percent annual return. The overall average cost of capital is 15.0 percent. Future inflation is assumed to be 5 percent per year, yielding a real average cost of capital of 9.5 percent. Although results vary with specific field

Table S-1 — Estimates of Undeveloped Nonassociated Gas
(Trillion cubic feet)

Country	Total Gas Reserves (Associated and Nonassociated)* January 1, 1991	Estimates of Undeveloped Nonassociated Gas**
Abu Dhabi (U.A.E.)	182.8	47.1
Algeria	114.7	33.9
Argentina	27.0	16.9
Australia	15.4	62.0
Bangladesh	12.7	4.4
Canada (arctic)***	27.0	24.8
Chile (with blowdown gas)	4.1	6.4
China	35.3	9.7
Ecuador	4.0	0.4
Egypt	12.4	4.2
India	25.0	3.8
Indonesia	91.5	59.0
Iran	600.4	439.0
Iraq	95.0	8.7
Kuwait	48.6	0.0
Libya	43.0	6.9
Malaysia	56.9	21.5
Mexico	72.7	3.5
New Zealand	4.1	0.5
Nigeria	87.4	28.0
Norway (arctic)***	18.6	18.2
Oman	7.2	6.4
Pakistan	19.4	6.3
Papua New Guinea	8.0	8.6
Peru	7.1	17.1
Qatar	163.2	160.8
Russia, inciudlng the former U.S.S.R. (European export)	1,600.0	877.0
Russia (Pacific export)	—	27.0
Saudi Arabia	180.4	121.5
Trinidad and Tobago	8.9	11.9
U.A.E. (others)	17.6	9.6
Venezuela	105.7	9.9
Yemen	7.0	10.4
Total	3,703.1	2,065.4
United States	166.2	—

*_Oil and Gas Journal_ estimates.

**Energy and Environmental Analysis, Inc. (EEA), estimates; includes all identified fields with reserves greater than 100 bcf.

***Norwegian arctic and Canadian arctic reserve estimates obtained directly from government reports.

characteristics and development costs, these fiscal terms and financing produce roughly a 50:50 split of total gross revenue between the state and the working interests.

The value of condensate and gas plant liquids was assumed to be 90 percent of crude oil prices in the year 2000 according to the 1990 Energy Information Administration (EIA) forecast, expressed in 1989 dollars per million British thermal units (Btu) (U.S. Department of Energy 1990). The value of the liquids is not assumed to escalate in real terms. Section 4 contains a discussion of the sensitivity of this report's gas resource cost estimates to different financing arrangements and to liquids prices.

The price at which gas is offered for sale is assumed to have a lower limit of $0.25 per Mcf to account for the "opportunity cost" of the gas. This is approximately the discounted value of the gas if initial production is delayed 20 years from the year 2000 and natural gas prices then are 60 percent of projected year-2000 crude oil prices. A further discussion of opportunity cost is contained in section 4.

The results of the resource cost calculations for the countries in this report are contained in Table S–2 and graphically presented in section 5. This report identifies more than 1,264 tcf of undeveloped nonassociated sales gas in the world available for production costs under $3 per Mcf. A little more than half, 665 tcf, is available for under $1 per Mcf. These volumes are about one-third and one-sixth, respectively, of the present total gas reserves (remaining ultimate recovery) listed in the *Oil and Gas Journal* summary of worldwide gas reserves (Table S–1).[1]

As the figures in section 5 indicate, only the Persian Gulf countries have significant reserves available at a cost less than or equal to $0.25 per Mcf. Algeria, Saudi Arabia, Iran, Indonesia, the United Arab Emirates, and Qatar possess the majority of the inexpensive undeveloped nonassociated gas in the countries studied. Indonesia and Algeria are the only countries outside the Persian Gulf area that have inexpensive reserves exceeding the volume held by Oman, the smallest Persian Gulf nation studied.

Gas reserves in Iran and Russia dwarf volumes discovered in any other country. However, the proximity of Iran's fields to ports along the Persian Gulf coast and to the established oil and gas production infrastructure makes them far cheaper to develop for export than the remote fields of the former Soviet Union. Including pipeline costs to an ice-free port, fields in territories formerly comprising the Soviet Union contain estimated undeveloped nonassociated gas reserves of 9 tcf available for less than $1.00 per Mcf. Iran has 296 tcf available at the same costs. Russia has by far the greatest volume of oil and gas reserves of any of the former Soviet republics.

The single component of field development costs that was most influenced by the requirement that gas be delivered to a port for export in this study is pipeline costs. In many instances, most notably in Russia, Argentina, Peru, and Papua New Guinea, pipeline costs add as much as $8.00 per Mcf to estimated development costs. If only transportation to the existing or potential nearby gas trunkline system is included in Russian supply costs, about 26 tcf of gas is available for under $1.00 per Mcf, as compared with the 9 tcf available at that price delivered to a port using all new pipelines.

Several sensitivity cases were run on an example field to illustrate the impact of financing assumptions, government fiscal regimes, liquids value, and production rates. The first case in Table S–3 is an estimate of gas resource development costs with zero government take and zero cost of capital. Case B is a resource cost estimate using the standard assumptions in this report (60 percent equity at 20 percent return, 40 percent debt at 12 percent interest, 40 percent royalty, 37.3 percent income tax, and liquids value based on $27.80 per barrel oil price). The remainder of the cases are variations of the standard assumptions. Reserves and

[1]These two estimates of gas reserves were not derived on a comparable basis. The EEA estimates of undeveloped nonassociated gas include probable reserves. The OGJ estimates include both associated and nonassociated reserves, developed and undeveloped, and probably include only estimates of proved reserves in those countries where it is possible to segregate probable reserves estimates. The reserve estimates in this report are therefore a subset of the OGJ reserves plus additional probables.

Table S-2 — Estimates of the Resource Costs of Undeveloped Nonassociated Gas
(Trillion cubic feet)

	Estimated Undeveloped Nonassociated Gas*	Sales Gas Available at Resource Cost < $5/Mcf	Sales Gas Available at Resource Cost < $3/Mcf	Sales Gas Available at Resource Cost < $1/Mcf
Abu Dhabi (U.A.E.)	47.1	38.9	38.9	35.0
Algeria	33.9	30.0	28.3	15.0
Argentina	16.9	15.6	15.6	7.0
Australia	62.0	41.0	14.6	4.2
Bangladesh	4.4	3.0	3.0	0.0
Canada (arctic)	24.8	19.6	13.6	0.0
Chile (with blowdown gas)	6.4	6.1	6.1	5.8
China	9.7	5.8	2.8	0.0
Ecuador	0.4	0.4	0.4	0.0
Egypt	4.2	3.2	3.1	1.0
India	3.8	2.0	1.7	0.0
Indonesia	59.0	35.2	33.3	14.4
Iran	439.0	397.3	390.8	296.0
Iraq	8.7	7.7	7.5	7.3
Kuwait	0.0	0.0	0.0	0.0
Libya	6.9	5.3	4.6	3.5
Malaysia	21.5	19.0	18.7	6.1
Mexico	3.5	2.9	2.9	2.7
New Zealand	0.5	0.2	0.2	0.2
Nigeria	28.0	22.9	20.2	9.9
Norway (arctic)	18.2	2.6	0.0	0.0
Oman	6.4	6.0	4.7	3.7
Pakistan	6.3	0.8	0.6	0.0
Papua New Guinea	8.6	6.4	5.3	0.0
Peru	17.1	14.0	14.0	0.0
Qatar	160.8	133.7	133.7	127.6
Russia, including the former U.S.S.R. (European export)	877.0	556.6	347.5	9.0
Russia (Pacific export)	27.0	15.2	15.2	0.6
Saudi Arabia	121.5	99.8	99.8	96.3
Trinidad and Tobago	11.9	11.2	11.2	1.9
U.A.E. (others)	9.6	7.9	7.9	6.7
Venezuela	9.9	9.0	8.9	1.3
Yemen	10.4	9.8	9.8	9.8
Total	2,065.4	1,529.1	1,264.9	665.0

*Includes all identified fields with reserves greater than 100 bcf.

Table S-3 — Effects of Fiscal and Financial Assumptions on Required Gas Revenue From an Example Field
(Real 1989 dollars per thousand cubic feet)

Case		Raw Gas	Sales Gas
A	Zero Government Take, No Discounting	0.81	0.33
B	Tax, Royalty, Financing Costs Added	3.01	2.53
C	100% Equity Financing, 20% Return on Equity	3.84	3.36
D	100% Equity Financing, 30% Return on Equity	4.11	3.62
E	As B, 10% Increase in Costs	3.31	2.83
F	As B, No Royalty	1.81	1.32
G	As B, No Income Tax	2.50	2.02
H	As B, Liquids Value $20/bbl Oil	3.01	2.66
I	As B, 25-Year Project Life	2.85	2.36
J	As B, Initial R/P Ratio = 15	1.94	1.46

investment costs are the same in each case, with the exception of Case E. These sensitivities are discussed in more detail in section 4.

A variety of royalty schedules and production-sharing contracts are utilized by host governments in their administration of oil and gas development. In recent years, with continued low oil prices, many countries have eased their royalty requirements and restrictions on operations of private companies. Norway, in fact, has eliminated royalty payments on new developments, but the government imposes a special tax on petroleum production in its stead, and the state oil company may retain a large working interest in most fields, with an option to increase that interest after production has started.

The high cost of Norwegian fields provides a good example of the impact of government fiscal regimes on the cost of development. The lowest-cost Norwegian field, with reserves of about 2.5 tcf sales gas, requires revenue of $3.70 per Mcf for development under the standard set of assumptions. The same field with no royalty requires only $1.66 per Mcf ($2.04 per Mcf less) to develop.

The resource cost calculations in this study are for that hypothetical arrangement in which the operator has a 100-percent working interest and the state is compensated through a royalty and income tax arrangement. As stated earlier, the state receives approximately 50 percent of total revenue including taxes under this fiscal regime. The producer must pay all development costs, debt, and equity return out of the remainder.

The primary objective of the Alternative Fuels Assessment program is to evaluate transportation fuels. Natural gas with costs of $1 per Mcf contributes $0.09 per gallon to methanol costs. Methanol conversion costs add anywhere from $0.18 to $0.53 per gallon. Transportation costs to the United States add from $0.024 to $0.112 per gallon. Appendix D contains a discussion of methanol conversion and transportation costs. These costs must be added to the natural gas resource costs developed in this study in order to evaluate the full costs of methanol imports and their potential competitiveness with gasoline or other motor-vehicle fuels.

I. METHODOLOGY

INTRODUCTION

All significant accumulations of natural gas in each country studied were examined to assess their undeveloped nonassociated gas reserves and to determine requirements for their development. The cost of developing any gas field will depend on several factors:

- Drilling depth.
- Water depth (if offshore).
- Size of accumulation.
- Rate of production relative to reserves.
- Well productivity.
- Location of accumulation relative to market.
- Nonmethane constituents in the gas.
- Degree of oil and gas infrastructure in the country or region.

All of these characteristics were gathered or estimated for each field determined to contain undeveloped nonassociated gas. Undeveloped fields were defined as those in which no production has taken place or is not scheduled to start in the next year or two. The inventory of undeveloped fields was extended to include large nonassociated gas fields that have production utilizing only a small fraction of their potential capacity. Undeveloped reserves in these fields were estimated to include those reserves that would remain after the currently producing wells deplete. Examples of these partially developed fields are Ghawar (Saudi Arabia), Margham (U.A.E.), F6 and E8 (Malaysia), Tunu (Indonesia), and Rhourde Nouss (Algeria), Reynosa-Profundo (Mexico), and Dalan and Kangan (Iran). In addition, if large volumes of gas were known to be cycled for condensate recovery with no current market for the gas, surplus gas reserves in those fields were included in the study. The most outstanding example of this is in Chile's Tierra del Fuego gas fields. In large gas fields in Algeria, Abu Dhabi, and Trinidad, hydrocarbons are produced, liquids are extracted, and gas is reinjected into the same reservoir or into separate oil or gas fields for later blowdown. In general, reinjected gas utilized in pressure-maintenance projects was not included in this study.

DATA SOURCES

The research for this study used numerous oil and gas industry trade publications, U.S. Department of Energy (DOE) surveys and publications, trade group surveys, energy economics papers, maps published by various sources, past studies by Energy and Environmental Analysis, Inc. (EEA), and personal contacts.

The major source of information on discovered nonassociated gas deposits was the *International Oil and Gas Fields Records* data base created by Petroconsultants Ltd. of Geneva, Switzerland. This data base is licensed by the Energy Information Administration (EIA) for use by the U.S. Geological Survey (USGS) and was made available to EEA for this project. Most of the Petroconsultants data available for this study was updated through midyear 1989. Supplemental data on discovered gas fields were obtained from the American Association of Petroleum Geologists publication *AAPG Bulletin,* the *Oil and Gas Journal, World Oil, Offshore,* and *Petroleum Economist.*

Component costs for field development were estimated from various published cost data and engineering estimates made by EEA. The major sources of drilling cost data were the *Joint Association Survey of Drilling Costs* and the *Expenditure Survey,* both published by the American Petroleum Institute (API). Well equipment and operating costs were obtained from estimates published by EIA. Offshore platform construction costs were estimated from periodic reports appearing in the publications *Offshore, Ocean Industry,* and *Journal of Petroleum Technology.* Past studies by the USGS and the Office of Technology Assessment (OTA) also were used to estimate offshore development costs.

ANALYSIS

Several distinct stages of analysis were required in assessing each natural gas deposit:

- Estimates of the undeveloped nonassociated gas in each field that was examined. These reserves estimates were made using data contained in the Petroconsultants data base and information published in trade journals, and through application of reservoir engineering principles.
- Estimates of the physical infrastructure and investment required to develop each field. These estimates were based on the reserves and well capacity for each field and the required project life. A standard set of cost assumptions and algorithms was used to develop well, equipment, and pipeline costs.
- Estimates of the costs of developing the natural gas resource in each field, calculated in a discounted cash flow model. The economic model employs a standard set of financial and economic assumptions to calculate the revenue required by the operator to produce and transport the gas to the nearest port location.

Key geologic and engineering data on each field were obtained from the Fields data base and various industry publications. In cases where key data were unobtainable, EEA estimated values based on analogous fields.

If the data available were sufficiently detailed, published reserves estimates were checked for reasonableness with EEA's own volumetric calculations. Many fields have numerous stacked reservoirs in different geologic horizons containing oil, gas, and oil with gas caps. The Petroconsultants data base does not distinguish between associated and nonassociated gas, nor do most published estimates.

The development scheme and investment required for each field is dependent on the reserves, well productivity, and demands of the market served (in this case, a gas liquefaction or methanol plant). The number and timing of wells, the size of platforms and equipment, and the size and length of pipelines were estimated for each field or group of jointly developed fields.

The estimated cost of the wells, platforms, equipment, and pipelines for each development was based on the size requirements and location. Reservoir depth and surface location were taken into account when estimating well costs. Offshore platform costs are a function of water depth, the number of well slots, and platform type. Very-deep-water locations were assumed to be developed with tension-leg platforms. Production equipment costs are dependent on throughput and the sour gas (carbon dioxide (CO_2), hydrogen sulfide (H_2S)) content of the production wellstream. Pipeline requirements and costs are determined by the production volumes, condensate yield, and surface location (offshore, marsh, or land). Reserves and production assumptions are explained in more detail in section 2.

The original basis for most cost estimates are costs in the United States and the offshore Gulf of Mexico. The United States is a mature petroleum province with extensive infrastructure development and experience to draw upon. Cost information gathered and reported by DOE, trade groups, and industry publications is reliable and broadly based. Much of the equipment in use around the world still is manufactured in the United States. The United States also has, by far, the largest number of offshore platforms and miles of pipeline in the world. Costs were adjusted for each field if the location required unusual transportation, installation, or infrastructure investment. For example, equipment costs were increased 25 percent in the Middle East and South America. Well, equipment, and offshore platform costs were increased 100 percent in Nigeria. In earthquake risk areas such as Venezuela and Trinidad and harsh environments such as Tierra del Fuego, the Norwegian Sea, the Barents Sea, and the Sea of Okhotsk, offshore platform costs were increased 60 to 133 percent. In the relatively calm, shallow South China Sea, close to fabrication yards, platform costs were reduced 20 percent. Additional cost adjustments were made for sour production, marsh locations, and arctic and deepwater developments. Bases for these adjustments are published cost reports in industry journals and in DOE and USGS reports and personal contacts. Cost assumptions are explained in more detail in section 3.

Development costs were computed on a dollar-per-thousand-cubic-feet (Mcf) basis using a spreadsheet model for evaluating oil and gas exploration and development economics. A standard discounted cash-flow technique is used to determine the resource cost for gas given a certain minimum rate of return, tax treatment, and royalties. The economic analysis for each field or group of fields utilizes the present value of the total investment required to develop a field as the cost input. Financial assumptions include a standard debt/equity ratio, interest rate, tax and royalty rate, and return on equity for each field. The project life, for purposes of calculating the required value of the production, is 15 years, based on the assumed project life of a methanol or liquefied natural gas (LNG) plant. All costs are in 1989 dollars.

Many of the fields in this study will produce significant amounts of condensate along with the gas and large amounts of hydrocarbon liquids after processing in a gas plant. In fact, many of the fields in Algeria and the United Arab Emirates currently are produced solely for their liquids. The gas is flared or reinjected. The final calculation of the cost of development and production of sales gas takes into account the value of the produced condensate and plant liquids (ethane, propane, butane, pentanes, and natural gasolines). The value of these liquids is subtracted from the total cost that must be recovered by the sales gas.

In some cases, the value of the liquids is so great that the calculated required cost recovery from the sales gas is very low or even zero. For these fields, the value of the gas is assumed to be $0.25 per Mcf so as to place a realistic value on the future opportunity cost of the gas. This very inexpensive gas is found mainly in the large onshore Middle East gas fields. An example resource cost calculation is explained in more detail in section 4.

PETROCONSULTANTS DATA-BASE ANALYSIS

The Petroconsultants Fields data base was the primary source of data for estimating quantities of undeveloped or unutilized nonassociated gas reserves. Software to manipulate the data was developed using the SAS statistical software package. During early stages of analysis, it became clear that the data were not complete enough for an automated reserves assessment. Therefore, several reports were used to identify the fields of interest and pull together key reservoir data.

National or field-level reserves estimates that lump nonassociated and associated reserves, or developed and nondeveloped reserves, were not sufficient for this study. Ideally, the following data would be available for each reservoir: recoverable gas estimate, depth to productive interval, lithology, initial flow rates, gas composition, reservoir temperature and pressure, water saturation, porosity and permeability, net pay thickness, type of drive, reservoir areal extent, and geographic location.

The Petroconsultants Fields data base contains many types of data records for each field, covering varying levels of detail. There are a total of 31 unique types of records and more than 400 unique variables potentially available for a given field. Some of the major items include the following:

- Field-level data.
  - Name, type, year of discovery, and location.
  - Production time series and cumulative production.
  - Reserves estimates.
  - Comments describing various aspects of the field.
- Reservoir-level data.
  - Name, lithology, and type.
  - Depth, pay thickness, porosity, gas composition, and so forth.
- Well test data.
  - Interval tested, test recoveries, pressures, and so forth.

The Petroconsultants data base lacked many of the key reservoir data items. Reserves and production data are reported at a field level. Nonassociated and associated gas volumes are not disaggregated. Test data and detailed reservoir data often are not present. However, the comment records contained valuable information. The fact that many of the data for the fields of interest were contained in the comments, rather than in specific variables, made it impossible to automate the assessment of reserves.

Large, developed fields had the most complete information, while recent discoveries or undeveloped fields and reservoirs had less detailed information.

Methodology

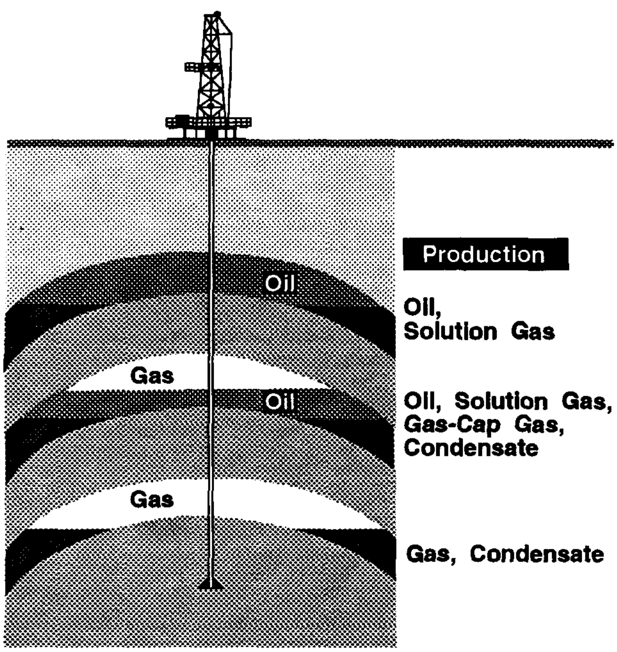
Several programs were developed to create reports from the data base at varying levels of detail and aggregation. The reports printed records of both comments and data so that all available data could be used together. The first step was to generate a one-page summary report of each field in the data base, along with a list of nonassociated gas reservoirs ranked by total field-level reserves. These two reports then were used to screen the data manually to select a subset of fields for more detailed analysis. A detailed report then was generated for the subset of fields thought to have undeveloped or unutilized nonassociated gas reserves.

II. RESERVES AND PRODUCTION ESTIMATES

INTRODUCTION

This section describes the data available for the field-by-field estimates of reserves and production capacity and the screening procedure used to identify potential sources of undeveloped nonassociated gas. It is useful at this point to review the global context of natural gas reserves and production rates. The United States is producing its proved gas reserves at a much higher rate than most other countries. A common indicator of the relative depletion rate of hydrocarbon reserves is the reserves-to-production ratio (R/P ratio). All things being equal, a high R/P ratio indicates reserves are being produced at a very low rate. Table II–1 summarizes the approximate 1990 R/P ratio for the countries in this report. The United States produced 21.0 trillion cubic feet (tcf) of natural gas in 1990, out of 166 tcf of reserves. After reinjected gas is accounted for, net consumption was 18.5 tcf. This yields an R/P ratio of 9.0. The Soviet Union consumed about 29 tcf in 1990, out of 1,600 tcf of reserves. The U.S.S.R. R/P ratio was about 53.0 in 1990. The rest of the world combined (excluding the United States and the U.S.S.R.) consumed only 31.5 tcf. The average R/P ratio in the countries covered in this report was 71. As Table II–1 illustrates, the U.S. gas reserve depletion rate is nearly 8 times as great as the non-U.S. average (U.S. R/P ratio of 9 versus 71 outside the United States).

Figure II-1 — Types of Natural Gas Deposits



Many factors influence the R/P ratio, including the reserves booking policy of the country, current local gas infrastructure limitations, source of the gas (associated versus nonassociated), and the actual disposition of the gas (that is, if large-scale gas reinjection programs are in progress). Algeria, Abu Dhabi, Chile, Iran, Venezuela, and Indonesia reinject a large portion of their gross gas production. The production figures quoted in Table II–1 are net of reinjection.

OBJECTIVES AND METHODOLOGY

Most of the fields analyzed contain numerous stacked reservoirs deposited through geologic time. These reservoirs may contain oil with varying amounts of gas in solution, oil with free gas caps, or only gas. The latter type is defined as nonassociated gas and is the subject of this report. Figure II–1 illustrates the various types of natural gas deposits. Most publicly available reports do not distinguish nonassociated gas reserves from associated gas reserves when both types of gas are found in a field. The Petroconsultants data base frequently lists the major geologic formations within a field, but contains only estimates of reserves at a field aggregate level. The reserves estimate portion of this study has identified the major accumulations of gas in each country and estimated the portion that is nonassociated gas. The potential productive capacity of each field also has been estimated.

Utilizing Petroconsultants data for each field when available, and supplementing that information with data for nearby and analogous fields contained in Petroconsultants or other published sources, an initial field list of potential sources of nonassociated gas was

Table II-1 — Worldwide Gas Production Rates and Reserves

	OGJ Total Gas Reserves (Associated and Nonassociated) 1990 (tcf)	EIA Estimates Marketed, Flared Gas Production 1989 Total (tcf)	Approximate 1990 R/P Ratio
Algeria	114.0	2.119	52.0
Argentina	27.3	0.874	30.2
Australia	16.5	0.635	25.1
Bangladesh	12.4		
Canada	94.3	4.269	21.3
Chile	4.2	0.072	56.4
China	35.3	0.505	67.5
Ecuador	4.0		
Egypt	11.7	0.317	35.7
India	23.0	0.495	44.8
Indonesia	87.0	1.624	51.8
Iran	500.0	0.904	534.4
Iraq	95.0		
Kuwait	48.6	0.388	121.0
Libya	25.5	0.346	71.2
Malaysia	51.9	0.617	81.3
Mexico	73.4	1.304	54.4
New Zealand	5.1	0.173	28.5
Nigeria	87.4	0.780	108.3
Norway	82.2	1.183	67.1
Oman	9.3	0.183	48.9
Pakistan	18	0.475	36.6
Papua New Guinea	4.5		
Peru	7.1		
Qatar	163.2	0.247	638.4
Russia, including the former U.S.S.R.	1,600.0	29.153	53.0
Saudi Arabia	181.4	1.544	113.5
Trinidad and Tobago	10.0	0.279	34.5
U.A.E., including Abu Dhabi	200.4	0.965	200.6
Venezuela	100.8	0.881	110.5
Yemen	7.0		
Total	3,700.4	50.3	71.0
United States	166.2	18.525*	9.0

Note: At time of writing, preliminary reports of 1990 dry gas production were on average 3.5 percent higher than 1989 dry gas production volumes.
Reinjected gas volumes have been subtracted from gross production.

*1990 actual

created. The amount of nonassociated undeveloped gas and the production capacity of average wells in each field were estimated using the following methods or sources:

- Field-specific published reports.
- Volumetric calculations based on Petroconsultants data.
- Engineering judgment based on analogous fields.
- Petroconsultants field-level estimates for smaller, primarily gas fields.

The estimation methods above are listed in decreasing order of reliability because of the decreasing amount of data behind each.

DISCUSSION OF RESERVES AND PRODUCTIVITY ESTIMATING PROCEDURE

In general, the reserves estimates in this report tend to be conservative (that is, they err on the low side) because of the early stages of exploration and reservoir definition in many of these fields. In many cases, only one or two wells have been drilled into the gas-bearing formations and little or no production testing has taken place. As more wells are drilled within the field, it is very likely that more reserves will be proved based on the historical pattern of reserve additions to existing fields in North America.

Several important terms used throughout this report are defined below:

- *Proved reserves*—quantities of oil and gas estimated with reasonable geologic and engineering certainty that are recoverable under current economic conditions.
- *Probable reserves*—quantities of oil and gas that may be estimated with data gathered to date, but are generally not supported by definitive tests.
- *Estimated ultimate recovery (EUR)*—total cumulative production expected during the field or well life.
- *Remaining ultimate recovery (RUR)*—expected cumulative production to be produced from the time of the estimate to abandonment; RUR plus cumulative production to date equals EUR.
- *Raw gas production, reserves*—full wellstream production before gas processing that removes nonhydrocarbon gases and natural gas liquids.
- *Natural gas liquids (NGL's)*—hydrocarbon fractions heavier than methane that exist in a gaseous state in the reservoir and are extracted during processing for pipeline transmission; generally includes propane and heavier compounds; ethane is selectively extracted depending on market conditions.
- *Sales gas, pipeline gas, plant residue gas*—terms used interchangeably to describe the gas composition and volume remaining after gas processing; the primary component is methane, but will also include varying amounts of ethane, CO_2, and nitrogen; volume will be reduced from the raw gas volume after extraction of NGL's, nonhydrocarbon gases, and fuel use.

Reserves estimates quoted in this report and used to develop the natural gas supply curves in section 5 are for the most part the sum of proved plus probable reserves.

The productive capacity of a field is determined both by the physical limits of the formation and wells and by the economics of the development strategy. This study assumed fields are developed such that a constant flowrate is achieved for 15 years to supply an LNG or methanol plant with a constant source of feedstock. A long-term, reliable supply of gas will allow the most efficient design and sizing of a plant. A 15-year plant life is based on the depreciation life of the major infrastructure components of a plant (Chem Systems 1989).

Most gas wells will produce for 10 to 25 years. Therefore, the field total annual flowrate primarily is dependent on the capacity and decline rate of individual wells. An initial R/P ratio of 25 was used as the basis for estimating the annual production from the field. In the examples in this report, a constant flowrate is maintained during the first 15 years by drilling additional wells as production from older wells declines. For example, a field with reserves of 1,000 billion cubic feet (bcf) will be developed so that production lasts 40 to 50 years. Our development plan requires production of 110 million cubic feet per day (MMcfd) during the first 15 years.

The initial productive capacity of individual wells in each field was taken from available test data or inferred from analogous fields. The decline rate of individual wells was assumed to be similar to U.S. wells in reservoirs with like physical characteristics. In general, decline rates were assumed to be between 11 percent and 15 percent per year. For example, wells completed in the thick Arabian Khuff carbonates were assumed to decline at 11 percent per year after an initial 2-year period of no decline. Completions in the thin, highly permeable Nigerian sandstones were assumed to decline at 14 percent per year.

The development timeframe for the fields in this study is around the year 2000. In many of the large nonassociated gas fields, a few wells have been drilled as a supplementary source of natural gas for domestic consumption. The primary source of gas in most of these countries is associated gas from oil production. As that supply has fluctuated or declined, some portions of previously discovered nonassociated gas fields have been produced. For example, as Saudi Arabia's oil production dropped from nearly 10 million barrels per day (MMBD) to about 4 MMBD in the 1980's, the drop in associated gas production required development of nonassociated Khuff formation reserves. By yearend 1990, production capacity from the Khuff was reported to be nearly 2.1 billion cubic feet per day (bcfd) (Pennwell 1989; Cranfield 1989; Petroconsultants 1989). If this nonassociated gas production were maintained at capacity for 10 years, total production still would amount to only 7.5 tcf—only 6 percent of the estimate of proved undeveloped nonassociated gas. This production rate is equal to an R/P ratio of 163 for the nonassociated gas. For these reasons, the majority of Saudi Arabian Khuff gas reserves were included in this report as undeveloped. Similar situations exist in some of the large fields of the U.A.E., Iran, Russia, and Algeria.

Some fields contain reservoirs with very thin oil rims and very large gas caps. While technically this is associated gas, the value of the gas is greater than the oil, and the oil leg will be depleted rapidly once production begins. This situation occurs most notably in some of the Norwegian gas fields and in some of the light oil reservoirs of Venezuela and Malaysia. If the overall gas-to-oil ratio (GOR) in these fields exceeds about 12,000 cubic feet per barrel, and the primary product will be gas, they were included in the nonassociated gas field inventory.

Condensate reserves were estimated from production test data in Petroconsultants or other published reports. If test data for a field were not available, condensate yields from a nearby field or fields with similar fluid composition were used as analogies. Condensate yields can be critical to the economic viability of many of the fields studied. Development costs in many Venezuelan gas fields would render most gas projects uneconomic were it not for the high condensate yields. As mentioned earlier, in some of the most prolific fields the value of the condensate and plant liquids alone is enough to pay back the investment costs.

Gas plant liquid yields were estimated from compositional analysis contained in Petroconsultants or other published reports. All propanes and heavier hydrocarbons were assumed to be recovered, as well as 50 percent of the ethane in the produced gas. If no analysis was available, an estimate of shrinkage after processing through a gas plant was made from published reports of gas plant volumes and products in the area (Oil and Gas Journal Worldwide Gas Processing Report 1989, 1990; Moore and Sigler 1987).

EXAMPLE RESERVES ESTIMATE

Data for Qatar, as reported by Petroconsultants, are contained in Table II–2. The fields listed are those containing the greatest amount of gas. Because Petroconsultants does not compile reserves by formation or reservoir, the fields and reservoirs in Table II–3 were selected for additional study. As these figures indicate, some of the fields with large amounts of gas contain none or only small amounts of nonassociated gas. Conversely, some fields identified as oil producers also contain nonassociated gas reservoirs (that is, Dukhan Field). Much of the information related to the selection of fields suspected of having nonassociated gas

Table II–2 — Ten Fields With Most Gas Reserves in Qatar

Field or Reservoir	EUR Gas (bcf)	EUR Cond. (MMB)	EUR Oil (MMB)	Primary Product	Wells Drilled	Nonassociated Gas (bcf)
North	150,000	4,500	200	gas	31	150,000
Dukhan	8,200		4,100	oil	311	?
Bul Hanine	4,700		1,300	oil/gas	29	?
Idd el Shargi - N	3,200		1,000	oil/gas	34	?
Maydan Mahzam	2,400		1,100	oil/gas	39	?
Idd el Shargi - S	25		50	oil	5	?
Al Karkara	20		50	oil	1	?
A-structure North	10		30	oil	3	0
A-structure South	10		30	oil	3	0
Najwat Najem 2	?		50	oil	2	?

Source: Petroconsultants data
EUR = estimated ultimate recovery

Table II–3 — Fields With Significant Nonassociated Gas Reserves in Qatar

Field or Reservoir	Field Totals: EUR Gas (bcf)	EUR Cond. (MMB)	EUR Oil (MMB)	Field Primary Product	Year of Discovery	Status	Field Total Wells Drilled to Date	Nonassoc. Gas Reservoir	Depth (ft)
North	150,000	4,500	200	gas	1971	Undeveloped	31	Khuff 1	8,400
North						Undeveloped		Khuff 2,3	9,000
North						Part. Developed		Khuff 4	9,500
Dukhan	8,200		4,100	oil	1940	Developed	311	Khuff	9,500
Bul Hanine	4,700		1,300	oil/gas	1970	Undeveloped	29	Arab	7,400
Bul Hanine						Undeveloped		Areaj	8,500
Bul Hanine						Undeveloped		Khuff	12,200
Idd el Shargi - N	3,200		1,000	oil/gas	1960	Undeveloped	34	Khuff	10,500
Maydan Mahzam	2,400		1,100	oil/gas	1963	Undeveloped	39	Areaj	8,140
Maydan Mahzam						Undeveloped		Izhara	8,350

Source: Petroconsultants data

reserves was obtained from analysis of the limited production and reservoir data contained in the Petroconsultants data base. Additional information contained in the comments accompanying some fields in the data base and in other published reports was used to create a list of fields with suspected reserves of nonassociated gas.

Table II–4 outlines a typical volumetric calculation of the reserves potential of an identified nonassociated gas formation in the Bul Hanine Field, Qatar. Wherever possible, this sort of quick check of Petroconsultants data was performed as a reasonableness check and in order to assess the possibility of undocumented nonassociated gas reserves in the field. The Khuff formation is identified in Petroconsultants as primarily gas-bearing and 96 feet thick with a formation top at 12,200 feet. Formation pressure, porosity, and fluid composition were inferred from regional Khuff characteristics. The water saturation and abandonment pressure were estimated from reservoirs with similar characteristics in the United States. An areal conformance factor of 0.7 was applied to the calculated recovery factor to account for lack of knowledge of the

Table II–4 — Reserves Estimates for the Bul Hanine Field, Khuff Reservoir in Qatar

Petroconsultants information provided:

Bui Hanine field total surface acreage: 20,480 acres
Khuff Reservoir depth: 11,700 ft subsea
Net thickness: 96 ft

Inferred from data contained in other fields contained in Petroconsultants database:

Pressure gradient in Arabian basin: 0.53 psi/ft
Khuff gas composition: sour; 0.6 - 6% H_2S, 4 - 11% CO_2, N_2
Khuff porosity 12%

Inferred from analogy with U.S. Gulf coast reservoirs (Khuff analogous to Norphlet) and information published in other sources:

Water saturation: 30%
Abandonment pressure: 1,500–2,500 psi
Calculated recovery factor: 0.75 MMcf/ac-ft
Areal conformance factor: 0.7

Estimated Bul Hanine Khuff Reservoir recoverable gas:

(20,480 acres)(96 ft)(0.75 million cubic feet per acre-foot)(0.7) = 1,032 bcf (Raw gas)

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reservoir shape and drive mechanism. Based on these parameters, the Khuff formation in Bul Hanine should contain about 1,032 bcf of recoverable gas.

Table II–5 summarizes reserves estimates and deliverability estimates for all of the fields in Qatar that have significant nonassociated gas reserves. A total of 160.8 tcf of discovered, undeveloped nonassociated gas is estimated in Qatar.

A lower limit of 70 to 100 bcf of reserves per field was set for inclusion in this report's cost calculations. Total identified undeveloped nonassociated gas reserves for the countries in this report are about 2,065 tcf.

Table II–5 — Qatar Fields With Significant Nonassociated Gas Reserves

	Petroconsultants					EEA Estimates							
Field or Reservoir	EUR Gas (bcf)	EUR Cond. (MMB)	EUR Oil (MMB)	Primary Product	Gas Reservoir	Nonassoc. Gas (bcf)	Undev. N/A Gas (bcf)	Status	Depth (ft)	Avg. Max. Deliv./Well (MMcfd)	Reserves/ Well (bcf)	No. of Wells Req'd.	Location: Land, Offshore
North	150,000	4,500	200	gas	Khuff 1	16,000	16,000	Undeveloped	8,400	10	35	389	0
North					Khuff 2,3	64,000	64,000	Undeveloped	9,000	50	180	*	
North					Khuff 4	70,000	70,000	Part. Devel.	9,500	50	180	*	
Dukhan	8,200		4,100	oil	Khuff	1,440?	0	Developed	9,500	22			L
Bul Hanine	4,700		1,300	oil/gas	Arab	1,400?	1,400	Undeveloped	7,400	10	35	40	0
Bul Hanine					Areaj	1,000?	1,000	Undeveloped	8,500	10	35		
Bul Hanine					Khuff	1,050?	1,050	Undeveloped	12,200	22	80	*	
Idd el Shargi-N	3,200		1,000	oil/gas	Khuff	3,780?	3,780	Undeveloped	10,500	22	80	47	0
Maydan Mahzam	2,400		1,100	oil/gas	Areaj	2,000?	2,000	Undeveloped	8,140	15	55	36	0
Maydan Mahzam					Izhara	1,600?	1,600	Undeveloped	8,350	15	55	*	
					Total:	162,270	160,830						

Note: Adjusted data input to international gas data base.

*Initial well deliverablities based on published reports or estimated from similar U.S. Gulf Coast wells.
Individual well reserves estimates based on a 10-percent-per-year decline from initial rate.
Approximate 35-year-life-per-completion in main Khuff Reservoirs.
Nonassociated gas reserves in Bul Hanine and Maydan Mahzam estimated from net reservoir thicknesses contained in Petroconsultants data base.
North field Khuff Reservoirs broken out based on net thicknesses.

North field first-phase development production scheduled to start in 1991 at 800 MMcfd.

Source: Petroconsultants data (adjusted), reports in literature, EEA estimates.

III. COST ESTIMATES

OBJECTIVES AND METHODOLOGY

Development costs are estimated for all identified undeveloped nonassociated fields with estimated reserves greater than 99 bcf. In some cases, such as on the Indian subcontinent, few fields are that large. In these areas the reserves cutoff used was about 70 bcf. The timing of new wells and sizing of pipelines and equipment are dictated by the desired flowrate from the field. The assumption used here is that development wells are drilled as needed to maintain a constant total field production for 15 years.

After total field reserves, individual well reserves, and the field production were estimated, infrastructure and equipment requirements were determined. All investment necessary to bring production from the reservoir to a liquefaction or methanol plant, assumed to be located at the nearest port, is included in the cost of development. This includes all drilling and completion costs, offshore platform costs, production equipment, gas and liquids pipeline costs, and gas plant costs. An estimate of the discounted costs of field abandonment also is included. Overhead and financing costs are added to the total investment to arrive at a total development cost for each field or group of fields.

In areas where several fields lie close to each other, coordinated development is assumed. In these situations, significant reduction in cost is achieved by sharing equipment, gas plant facilities, and pipelines. For example, the 110 Indonesian fields included in the development cost calculations are grouped into about 40 developments. This approach yields a more realistic estimate of costs.

In areas extremely distant from a port, a field pipeline is assumed to be built to a junction with a large gas trunkline that then carries the gas the remainder of the distance to the port. At an average cost of more than $1 million per mile for large pipelines, pipeline costs are a major portion of total development costs. Shared trunklines are assumed for some of the fields in Algeria, Norway, China, India, Papua New Guinea, Russia, and Malaysia.

Component costs of each field are estimated with algorithms based on data published in various trade journals, API surveys, Federal Energy Regulatory Commission (FERC) filings, modified USGS and EIA studies, and personal contacts. As mentioned earlier, these costs are modified for each country as dictated by unique requirements of the location. The objective of this study is to estimate costs beyond the year 2000. The investment cost estimates developed are intended to represent the long-run average cost of developing a field, expressed in 1988 dollars. Recent fluctuations in regional costs such as the depressed drilling charges prevalent in North America, and the relatively high drilling costs seen in the North Sea, are assumed to be temporary.

Most cost estimates for the main component costs—drilling, offshore platforms, production equipment, pipelines, and gas processing plants—were derived from U.S. onshore averages and Gulf of Mexico offshore costs. North Sea and arctic region costs were estimated separately. Adjustments to costs in each country were made if local terrain or infrastructure requirements demanded greater investment. Table III–1 contains a summary of the local cost-adjustment factors used in the investment cost estimates.

The discounted cash-flow calculations for each field were made after bringing the component cost estimates up to 1989 dollars. The following section explains the sources and calculation method for average costs of each development component.

COMPONENT COSTS

Drilling and Completion Costs—Onshore

The primary source for drilling costs is the API Joint Association Survey on Drilling Costs (American Petroleum Institute et al. several years). Data from the past 20 years were used to analyze historical changes in drilling costs and to study the various changes in drilling component costs with depth. A cost floor and

Table III-1 — Estimates of Undeveloped Nonassociated Gas Development Costs

(Ratio to U.S. onshore average/offshore Gulf of Mexico costs)

	Drilling	Pipelines	Platforms	Equipment/ Processing
Abu Dhabi (U.A.E.)	1.00	1.00	1.00	1.25
Algeria	1.00	1.00	1.00	1.25
Argentina	1.00	1.00	—	1.25
Argentina (Tierra del Fuego)	1.00	1.00	1.60	1.50
Australia (Bass Strait)	1.00	1.00	1.00	1.25
Australia (interior, N.W. Shelf)	1.00	1.00	1.00	1.50
Bangladesh	1.00	1.50	1.00	1.50
Canada (Mackenzie/Beaufort)	7.65*	2.00	~ 50.0*	2.00
Canada (Arctic Islands offshore)	~ 12.0*	2.00	—	2.00
Chile (Tierra del Fuego)	1.00	1.00	1.60	1.50
China	1.00	1.50	—	1.50
China (Tarim)	2.00	2.00	—	1.50
China (offshore)	1.00	1.00	1.00	1.50
Ecuador	1.00	1.00	1.60	1.50
Egypt	1.00	1.00	1.00	1.25
India	1.00	1.50	1.00	1.50
Indonesia	1.00	1.00	0.80	1.50
Iran	1.00	1.50	—	1.50
Iran (offshore)	1.00	1.00	1.00	1.50
Iraq	1.00	1.00	—	1.25
Kazakhstan	1.50	1.00	1.50	1.50
Libya	1.00	1.00	1.00	1.50
Malaysia	1.00	1.00	0.80	1.50
Mexico	1.00	1.00	1.00	1.15
New Zealand	1.00	1.00	1.00	1.50
Nigeria (onshore marsh)	2.40	1.80	—	2.40
Nigeria (offshore)	2.40	1.80	2.00	2.40
Norway (Norwegian Sea)	3.00*	2.00	1.70 (TLP)	1.25
Norway (Haltenbanken)	3.00*	2.00	1.70 (TLP)	1.33
Norway (Troms)	4.00*	2.00	2.33 (TLP)	1.33
Oman	1.00	1.00	1.00	1.25
Pakistan	1.00	1.50	1.00	1.50
Papua New Guinea	2.40	1.75	1.25	1.75
Peru	1.00	1.50	1.60	1.50
Peru (jungle)	1.50	1.75	—	1.75
Qatar	1.00	1.00	1.00	1.25
Russia (Caspian Sea area)	1.00	1.00	1.50	1.50
Russia (E. Siberia)	7.65*	2.00	—	2.00
Russia (Sakhalin)	1.00	1.50	—	1.50
Russia (Sakhalin offshore)	4.00*	1.50	~ 60.0*	1.50
Russia (Komi)	1.00	2.00	—	2.00
Russia (Tyumen, Nenets)	7.65*	2.00	—	2.00
Russia (Barents Sea offshore)	4.00*	2.00	2.33 (TLP)	2.00
Russia (Kara Sea offshore)	4.00*	2.00	~ 60.0*	2.00

Table III-1 — Estimates of Undeveloped Nonassociated Gas Development Costs (continued)

(Ratio to U.S. onshore average/offshore Gulf of Mexico costs)

	Drilling	Pipelines	Platforms	Equipment/ Processing
Saudi Arabia	1.00	1.00	1.00	1.25
Trinidad and Tobago	1.00	1.00	1.60	1.00
Turkmenia	1.00	1.50	1.50	1.50
U.A.E. (others)	1.00	1.00	1.00	1.25
Ukraine	1.00	1.50	—	1.50
Venezuela	1.00	1.00	1.60	1.20
Yemen	1.00	1.00	—	1.25

Notes: All sour/acid gas (CO_2 greater than 6 percent CO_2 or trace H_2S) equipment costs increased by 3 times base costs.
Sour drilling costs increased by 50 percent.
Drilling costs are long-run average, approximately equal to 1984/1985 U.S. charges.
All marsh location drilling and equipment costs increased by 1.6 times base.
All deepwater fields include some subsea completions with additional costs.

*Different algorithm than GOM standard used—ratio is approximate.

a long-run equilibrium cost of drilling were calculated for the U.S. onshore and offshore (Energy and Environmental Analysis 1989, 1990). The equilibrium "full cost" was used as the basis for all drilling costs. Costs were estimated per foot of depth over 11 reservoir depth intervals onshore. The cost per foot ranges from a low of $39 for shallow wells of less than 5,000 feet to more than $600 for very deep wells of more than 20,000 feet. This wide range is due to the exponential increase in time required to drill deeper wells, as well as the increase in costs for equipment such as tubulars and muds. Handling equipment, tubulars, and drilling mud costs also increase significantly in sour or acidic fluid environments, roughly amounting to a 50-percent increase in total drilling costs. Marsh locations require barge-mounted rigs that increase costs by roughly 60 percent.

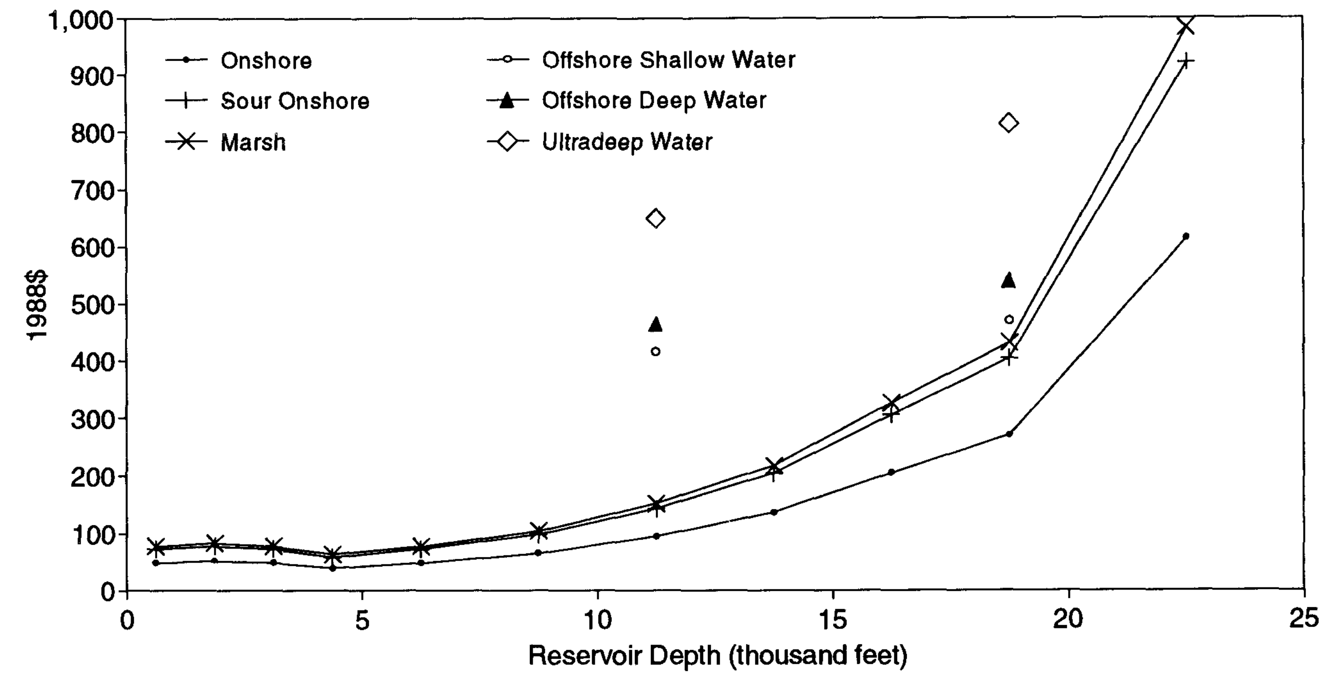
Figure III–1 illustrates the drilling cost estimates used. Further adjustments to drilling costs were made in specific areas as required, notably in Nigeria, Papua New Guinea, and arctic regions. Norwegian Sea drilling costs were estimated to be $1,200 to $1,850 per foot, with an additional cost increase of 33 percent in the Barents Sea (Norway and Russia). Nigerian and Papuan drilling costs were estimated to be 140 percent greater than the U.S. onshore because of difficult terrain and lack of infrastructure.

Drilling and Completion Costs—Offshore, Arctic

Offshore drilling cost estimates are developed in the same manner as onshore. Long-run equilibrium drilling costs for shallow-water jackups, moderate-water-depth jackups, and deepwater semisubmersibles were projected from rig and equipment replacement costs. In recent years, offshore drilling rates have fluctuated with local changes in rig utilization, and rigs have moved across the globe as demands dictated. A fairly mature global market in offshore drilling rigs and rig rates exists. Harsh climate areas such as the North Sea and arctic regions require much larger and stronger rigs than required in the Gulf of Mexico and South China Sea and command correspondingly higher rates. Offshore drilling costs are more sensitive to water depth than reservoir depth because of the relatively large fixed cost of rig mobilization for offshore wells. Nearly all offshore wells are highly deviated, and total drilling time does not vary as widely as onshore wells.

For these reasons, only two reservoir depth intervals are used for estimating offshore drilling cost per foot. The "full cost" average offshore well cost used in this report is a little more than $400 per foot of measured depth for wells shallower than 12,000 feet in Gulf-of-Mexico-type waters. A 15- to 25-percent

Figure III–1 — Average Long-Run Equilibrium Cost of Drilling Gas Wells in the United States



increase in cost per foot was used for reservoirs deeper than 12,000 feet. Additional increases of 50 percent are estimated for drilling in sour environments.

Deepwater developments are assumed to be drilled from tension-leg platforms with one-quarter of the wells completed subsea at an additional cost of $5 million per well. Deep water is generally assumed to be water deeper than 800 feet.

North Sea drilling costs were estimated in the same manner as Gulf of Mexico analogs. North Sea jackup rig day rates were assumed to be roughly 80 percent greater than in the Gulf of Mexico. North Sea platform rig rates were assumed to be roughly 55 percent greater. These costs were used only in the Norwegian North Sea and Norwegian Sea (Haltenbanken) fields. One-quarter of deepwater Norwegian and Russian wells were assumed to be subsea completions. These were assumed to be diverless wellheads, with several miles of flowlines and control umbilicals laid to the mother platform. Total subsea completion costs, including each well's share of a protective template and risers, was assumed to be $15 million.

arctic regions are generally defined as areas north of 64 degrees onshore and offshore in areas that are subject to significant winter sea ice. In the areas covered in this study, all of the Canadian frontier and much of Russia's undeveloped reserves are located in arctic regions. Cost estimates for developments in these areas are adapted from Mackenzie Delta-Beaufort Sea gas export license filings submitted to the National Energy Board of Canada in 1989 (Esso 1989).

Drilling costs are estimated to be $765 per foot both onshore and offshore because of the use of artificial islands in the offshore locations. Unique combinations of ice conditions and water depths in the arctic areas studied required the following assumptions:

- *Beaufort Sea (Canada)*—All fields in shallow water, developed from permanent artificial gravel islands; well costs same as arctic onshore.
- *Arctic Islands (Canada)*—All offshore fields developed with subsea completions (extra cost, $15 million per well), drilled from temporary artificial ice islands (extra cost, $4 million per well); drilling costs same as arctic onshore.

- *Barents Sea (Russia, Norway)*—All fields in generally ice-free areas; well costs 33 percent greater than North Sea.
- *Sea of Okhotsk, Kara Sea (Russia)*—All fields in ice floe areas, developed from gravity base platforms; well costs same as Barents Sea.

No exploration costs are included in the drilling investment. However, one exploration well is assumed to be reentered and completed as a producing well in each field. Even though all wells drilled in these estimates are development wells, some dry holes will be drilled. Historically, the number of development well dry holes in the United States has been about 15 percent of total development wells drilled. Drilling costs in each field are increased to include costs of nonproductive development wells at that ratio.

Offshore Platform Costs

Conventional steel jacket platforms are assumed for development of all fields in water less than 800 feet deep. In deeper waters, a tension-leg platform with satellite subsea wells is assumed.

Costs for conventional steel jacket platforms are adapted from cost equations in a USGS study (Attanasi and Haynes 1983). The study included cost estimates for oil and gas exploration and production in the Gulf of Mexico shelf. The cost-estimating equations were developed from vendor quotes. These costs include only the cost of materials, fabrication, and installation of the platform jacket; some portion of the deck; and piles. Costs for production facilities are not included. The cost equations calculate platform cost as a function of water depth and number of well slots. They are adjusted to convert costs to 1988 dollars for input into the economic model used in this study:

Conventional (fixed) platforms (water depth less than 300 feet):

$$C = 1.327 \times [2{,}570 + 0.0256(W)^2 + 185.6(S) + 0.715\,(W)(S)]$$

Conventional (fixed) platforms (water depth greater than 300 feet):

$$C = 1.327 \times [1{,}210 + 0.054(W)^2 + 71.87(S) + 1.12\,(W)(S)]$$

where

C = Cost in 1988 thousand dollars
W = Water depth in feet
S = Number of slots

The "standard" offshore development assumed in this report consists of at least one set of accommodations per field development. In most cases, conventional platforms are assumed to contain wellheads, production equipment, and living quarters. The algorithm used to estimate platform costs was based on a variety of hypothetical Gulf of Mexico developments. While cost estimates generated with this algorithm appear reasonable, they may or may not match a cost estimate put together by a particular operator. The costs estimated by the equations were compared against actual platform costs (adjusted for inflation) reported in *Ocean Industry, Oil and Gas Journal,* and various Offshore Technology Conference papers (*Ocean Industry* 1980, 1982, 1983; Karsan, Valdivieso, and Suhendra 1986). EEA also informally checked estimates generated by the algorithms against an independent operator's in-house benchmarks and found good agreement.

An exception to the report standard is the Persian Gulf, where most fields have separate platforms for living quarters. These fields are assumed to require one additional quarters platform for every two well platforms.

Platform sizes in each field in this report have been selected to minimize total platform costs. Northern North Sea, Norwegian Sea, and Barents Sea platforms historically have been very massive structures designed both to withstand the harsh climate and rough seas in the region and to act as anchors for future satellite field developments. Large primary separation and gas processing facilities have been placed offshore in the North Sea to feed gas directly into transmission pipelines. Large accommodation modules, opulent by Gulf of Mexico standards, have been set to house large numbers of maintenance personnel. As the North Sea matures, newer fields tend to use somewhat smaller platforms as the existing infrastructure requires less investment in completely self-sufficient developments. This has been the pattern as the Gulf of Mexico built up to its present level of about 4,000 platforms. Minimal accommodation units, primary separation facilities, and maintenance capabilities are employed on Gulf of Mexico platforms. The North Sea platform costs included here include a hefty premium over Gulf of Mexico costs, but probably correspond only to "minimal" Norwegian platforms.

Platform cost estimates for deep water are based on an analysis of published engineering cost estimates. The development scheme selected for a deepwater field is dependent on reserves and well productivity as well as water depth and capital costs. Deepwater fields are assumed to be developed with tension-leg platforms. About one-quarter of the wells in these fields are assumed to be satellite subsea completions. Platform costs for deepwater fields include the cost of a separate processing equipment platform in shallower water.

The only tension-leg platform set to date in the Gulf of Mexico, Conoco's Jolliet platform (1,760 feet of water), consists of hybrid subsea completions with wellheads on the surface of the platform. Total platform cost, including tendons and subsea template, is about $150 million. Another $50 million investment is required to construct a separate processing platform in shallower water. Floating tension-leg system costs are not very sensitive to water depth, relative to fixed conventional platforms. A summary of deepwater technology as of mid-1988 estimated tension-leg platform costs to be around $5,500 per ton of steel (Wickizer 1988). Total deepwater tension-leg platform costs were estimated with the following equation (including the separate shallow water processing platform):

$$C = 5{,}500 \times [16{,}500 + 8W] \times \text{(1988 thousand dollars)}$$

In offshore areas subject to extensive ice buildup, field developments were assumed to be carried out from permanent artificial islands if close to shore in shallow water, or gravity-based structures in deeper water. The cost of a structure in these areas was estimated with the following equation (*Oilweek* 1988):

$$C = [20 + 6.2\,(W - 12)] \times \text{(1988 million dollars)}$$

This algorithm was used for gravel islands intended to hold up to 75 wells or gravity-based structures for up to 44 wells. Analogs are the Hibernia structure offshore Newfoundland (250 feet of water, 83 wells, approximately $3.0 billion including overhead), proposals for Beaufort Sea development, and some of the Norwegian concrete platforms. Artificial gravel island costs include the cost of a causeway to shore and the necessary road and equipment infrastructure.

Adjustments to platform costs have been made in several areas:

- *Trinidad, Venezuela, Tierra del Fuego, Peru, Ecuador*—Cost increased 60 percent because of earthquake risk based on U.S. Pacific Coast practice (U.S. Congress 1988).
- *Norway*—Cost increased 70 percent for tension-leg platforms; cost increased an additional 33 percent in the Barents Sea because of the harsh climate and remote location.
- *Russia (Kara, Okhotsk)*—Cost of gravity-base structures increased 25 percent because of the remote location.
- *Nigeria*—Cost increased 100 percent because of lack of infrastructure and distance from fabrication yards.
- *Malaysia, Indonesia*—Cost decreased 20 percent because of close proximity to low-cost fabrication yards.
- *Papua New Guinea*—Cost increased 25 percent because of the lack of infrastructure.

Rig Mobilization

The costs of transporting and setting up rigs are included in offshore field development costs. One rig is assumed for each platform. Rig mobilization costs of $220,000 for jackups were common in 1988 (and are assumed in this study). A mobilization charge of $400,000 is assumed for semisubmersibles (deepwater).

Abandonment Costs

Abandonment costs for the shallow water areas are assumed to be $1 million per structure plus $200,000 per well. Well abandonment costs in the deepwater fields are assumed to be $500,000 each because of the use of a dynamically positioned semisubmersible drilling rig rather than a platform rig for the abandonments. Deepwater and arctic platforms are assumed to cost $10 million to abandon.[1]

Production Equipment

Costs of gas production equipment are calculated as a function of daily gas flow, based on an equation adapted from the USGS 1983 offshore study (Attanasi and Haynes 1983). Production equipment includes all surface equipment necessary for lease separation and fluids stabilization prior to transportation to a gas plant. This usually includes separators, heater treaters, anticorrosion chemicals, compressors, liquid storage tanks, and metering equipment. The offshore field development cost estimating algorithm implicitly assumes more complex platform topsides as platform flowrate increases. The costs for oil and gas production equipment were estimated with the following equation:

$$C = [0.636 \times (\text{MMcfd})^{0.421}] \times (\text{1988 million dollars})$$

where

MMcfd = million cubic feet of gas per day capacity

[1]Abandonment costs enter the discounted cash-flow calculation in year 1 as the present worth discounted at 10 percent, assuming that abandonments take place at the end of the average well's life. Under these assumptions, the present worth generally is less than 10 percent of the as-incurred costs.

Production equipment cost for highly corrosive service (more than 6 percent CO_2 or nontrace hydrogen sulfide) has been increased by a factor of 3 to reflect the much higher cost of corrosion-resistant alloys and the additional processing and safety equipment required.

Although this equation was originally developed for offshore equipment installations, it is used here as representative of total equipment costs in the newly developed onshore fields in this study as well. New onshore field developments also require roads, buildings, and utility connections. The costs of these additional items beyond primary separation and fluid handling will, of course, vary widely depending on location and degree of integration with nearby existing fields. Even within North America, costs vary widely. Well equipment costs reported by the EIA for U.S. wells in their annual survey are only 45 to 33 percent of similar expenditures in Canada. Onshore field equipment cost estimates in this report include the infrastructure items mentioned above in addition to equipment directly related to fluid handling.

Equipment delivery, installation, and construction costs in remote locations are increased to reflect the greater transportation and infrastructure development expense in some areas. Marsh location equipment costs are increased 60 percent. Further adjustments to cost are made based on infrastructure development and support facilities in different geographic areas. These adjustments, applied to both production equipment and gas plants, are based on several past studies of the cost of methanol plant construction in remote areas, as compared to the United States, and of the extent of oil and gas industry infrastructure development in the various areas studied (Chem Systems 1989; Chevron 1987; SRI International 1989). Table III–1 lists these geographic adjustment factors.

Pipeline Costs—Onshore

Gas and condensate pipelines have been included for all developments. Pipelines from each field are assumed to be laid to the nearest port where export tanker facilities exist, except for fields in very remote areas, which are assumed to tie into a gas transmission trunkline. Cost of a large trunkline is shared among the several fields that feed into it.

The cost of onshore pipelines varies widely depending on pipeline diameter and pressure, remoteness, terrain, stream crossings, right-of-way costs, and urbanization of the area crossed. Material costs are, on average, 37 percent of total costs; labor, 43 percent; right-of-way, 4 percent; and overhead and engineering, 16 percent. Costs used in this study for onshore pipelines are based on average U.S. costs published in the Oil and Gas Journal Pipeline Economics Report (True, several years). Costs range from $500,000 per mile for 6-inch line (the minimum used in this study) to $1,200,000 per mile for 36-inch line. The gas pipelines are assumed to operate at pressures between 750 and 1,000 pounds per square inch (psi), and it is assumed that any required compression will take place in the gas plant, which is included separately in our development costs. Condensate lines are assumed to be laid at the same time as gas lines. Costs of condensate lines have been reduced by 30 percent to account for savings in right-of-way and labor costs.

Costs have been increased in certain areas if the terrain is primarily marsh or if no infrastructure exists (for example, costs were increased 80 percent in Nigeria, 75 percent in the jungles of Peru and Papua New Guinea, and 100 percent in the Tarim Desert of China and in the arctic regions of Canada and Russia). Table III–1 lists geographic adjustments to pipeline costs. Pipeline costs have been included in the initial capital cost of field development for the purposes of this study. Pipeline costs are recovered over the same 15-year period used to estimate the required revenue for each field's economic development.

Pipeline Costs—Offshore

Offshore pipelines have been estimated with an adaptation of an algorithm developed by EIA in the Outer Continental Shelf Oil and Gas Supply Model (Farmer and Zaffareno 1982). The algorithm has been modified based on FERC filings during the 1980's (Federal Energy Regulatory Commission, several years). The cost of offshore pipelines is a function of size, length, and water depth. Costs may range from only $300,000 per mile for shallow small diameter lines to up to $1,500,000 per mile or more for large lines in deep water:

$$C = 2.026 \times [\mathrm{Exp}\,(10.4 + 0.82 \ln (L) + 0.88 \ln (D) + 0.09 \ln (W))] \times (1988 \text{ thousand dollars})$$

where

L = Pipeline length in miles.
D = Pipeline diameter in inches.

Few adjustments have been made to the cost of offshore lines in different geographic areas because of the similarities in techniques and conditions around the world. Costs in Nigeria are increased by 80 percent because of the lack of infrastructure. Costs offshore Norway are increased by 100 percent because of the highly irregular seafloor of the Norwegian Sea and the steep approach to shore.

Pipeline Costs—Trunklines

Implicit in including pipeline costs in the development costs is the assumption that production from these fields will exceed the capacity of existing lines, if any exist. In many areas this is obvious, as virtually no gas development has yet taken place. All fields considered in this study have been assessed significant pipeline costs to bring production to the nearest port or to the nearest proposed trunkline. In some cases, these pipelines are only a few miles long, as in most Persian Gulf countries, in the Canadian regions studied, and in most coastal areas. In other, more inland regions, such as China, Argentina, Pakistan, and the former U.S.S.R., much longer distances must be traversed, and pipeline costs will render individual field developments uneconomic. In some areas it is unclear whether a new pipeline dedicated solely to transporting production from the new fields to a port is necessary. For consistency, all developments are assumed to participate in the costs of construction of some portion of a new trunkline.

In some cases where an extensive high-capacity gas export pipeline network is known to exist, this study has assumed that field developments include only pipeline costs to a convenient tie-in point. For example, Algeria already has very large capacity to transport gas from Hassi R'Mel to the coast, and no additional trunkline construction beyond Hassi R'Mel was assumed necessary. The Canadian regions studied are very near the coast but are icebound much of the year. No pipeline construction to warm water was assumed in this study. Icebreaking tankers have already made oil deliveries from Canada's Arctic Islands. Because the emphasis of this study was methanol or LNG conversion of gas, transportation by tanker from Canada was assumed acceptable. Other examples are Russian production brought to the Western Europe export lines, northern Iran and Kazakhstan production brought to the former Soviet grid, and western China production brought to the Sichuan region.

In very remote areas, it is reasonable to assume that a large number of fields will be developed concurrently and will share in the cost of a major trunkline to the area of consumption or export. The two producing areas off Norway—Tromsoflaket in the Barents Sea and Haltenbanken in the Norwegian Sea—will require $500 million and $400 million, respectively, of investment in pipelines to bring gas and liquids ashore. Most of the undeveloped fields in Algeria are about 800 miles from the Mediterranean coast. Rather than burden each field or group of fields developed with a pipeline to the coast in these areas, the cost of a major trunkline from the producing area was divided among the fields.

In the Haltenbanken area, all fields share the cost of a gas and a condensate pipeline to Trondheim. In the Tromsoflaket area, all fields share the cost of pipelines to Hammerfest. By sharing costs, the initial capital costs of each trunkline amount to only about 3 to 7 cents per Mcf of nonassociated gas reserves. The Algerian fields in the Sahara, south of the very large oil field development at Hassi Messaoud and the gas development at Hassi R'Mel, are assumed to share in the costs of a liquids trunkline to Hassi Messaoud and a gas trunkline to Hassi R'Mel. Existing lines from these developments and lines already proposed are assumed to carry production the remainder of the distance to a port on the Mediterranean.

A similar approach was used in assessing trunkline costs to fields in Argentina, China, Egypt, India, Pakistan, Bangladesh, Papua New Guinea, Peru, and eastern Siberia. Depending on the number of fields available to share in the cost of the trunkline, costs varied from a few cents to more than $1.00 per Mcf of reserves.

Gas Plants

Gas plant construction has been included in the cost of every field. Even after lease condensate separation, significant amounts of NGL's are contained in most gas production. Gas plants strip out hydrocarbons heavier than methane and create a uniform residue sales gas, free of H_2S impurities and with reduced CO_2. The extracted gases—ethane, propanes, butanes, and natural gasoline—often have a value greater than that of the residue gas.

It is assumed that all propanes and heavier compounds, as well as about half the ethane, are extracted. As mentioned earlier, fluid composition data for each field were gathered from Petroconsultants data or reports on gas plant performance in the various areas studied. In most areas, gas plant recoveries were in the range of 1.5 to 3.0 percent of the total raw gas production (roughly 10 to 20 barrels per million cubic feet (bbl/MMcf). Some countries studied have much wetter gas production, ranging up to 14 percent shrinkage in some cases. Venezuela, Malaysia, Nigeria, Algeria, and the United Arab Emirates are the most notable producers of gas with a high content of NGL's. Gas plant shrinkage is estimated from the mol percent propane and heaviers in the gas composition. In cases where the composition was unknown, analogous field compositions were used.

Costs of gas plant construction have been estimated from published cost data (Worldwide 1988, 1989; Dorsett 1989; Hubbard and Reynolds 1989). Plant costs are based on a standard processing train size of 20 MMcfd and a maximum of 250 MMcfd. If the gas is corrosive—that is, greater than about 3 percent CO_2 or 0.05 percent H_2S—additional costs of amine or other processing units are included.

Saudi Arabia, Pakistan, and Iran have the greatest frequency of gas deposits that contain nonhydrocarbon gases. Some large Indonesian fields, most notably the huge AL–1 discovery offshore Natuna Island in the South China Sea, contain large amounts of CO_2.

Gas plant costs generally are 5 to 10 percent of total development costs. In smaller developments, plant costs may range up to 20 percent of the total development costs. Construction costs for each plant are adjusted to reflect the location and infrastructure requirements in each area using the figures in Table III–1.

Overhead

The cost of overhead (including support staff, management, and engineering design), contingencies, and construction financing is a significant expense in addition to the direct costs of equipment, labor, and construction. All component cost estimates have a uniform 50-percent overhead charge added to arrive at a total investment for development.

Operating Costs

Annual operating costs are included in the discounted cash-flow model for the 15 years of the project life. Operating costs include normal well maintenance, site maintenance, and direct overhead. Well maintenance includes corrosion inhibitors, flowline maintenance, meter and valve repairs, equipment fuel use and repairs, and periodic workovers. Direct overhead includes field office and personnel expenses. In most areas, onshore operating costs are assumed to be $50,000 per well per year. Offshore costs are assumed to be $150,000 per well per year. Arctic region operating costs are estimated to be $1,500,000 per well per year.

In addition, annual operating and maintenance expenses equivalent to 5 percent of the capital cost of plant and pipelines in all areas, and 1.5 percent of artificial islands in arctic regions are added to field development costs. Fuel use is assumed to be 2.5 percent of hydrocarbon gases except in arctic regions, where total fuel use is assumed to be 4.5 percent.

EXAMPLE INVESTMENT ESTIMATE

The estimated total investment for the Bul Hanine Field, Khuff Reservoir, is presented in Table III–2. The main input parameters are located at the middle of the table. Note that all costs are in 1988 dollars, the base year for input cost parameters into the discounted cash-flow model. Total reserves are estimated at 1,050 bcf, with individual well production starting out at about 22 MMcfd. The wells are assumed to decline at 11 percent per year, yielding 71.2 bcf per well, on average, over 35 years. At a total field R/P of 25, average production for this development will be 115 MMcfd. To maintain that rate for 15 years, production from 13.4 wells (rounded up to 14 wells) will be required. The present value equivalent of the cost of drilling these wells spaced out over 15 years is 70 percent of their total as-incurred costs.

Calculated investment expenses are displayed across the center of the table. Fourteen wells are required. At eight slots per wellhead platform, two wellhead platforms are required. Because of the high volumes produced by each well and the Persian Gulf practice of separating living quarters and production platforms, a total of five platforms will be constructed. Cost for each platform in the 115-foot water depth of the field location is $6.71 million. Total platform costs are $33.5 million. No cost adjustment for location has been made. Rig mobilization charges of $440,000 have been included, assuming two jackup rigs are in use during development drilling.

Cost of production equipment is estimated at $24.3 million, including an increase for sour production. Discounted abandonment costs for the wells and platforms are $500,000. (As-incurred costs of abandonment are about $7.5 million). Pipelines are assumed to be laid to Halil Island, about 25 miles away. The island has tanker loading facilities, and it has been assumed any liquefaction or methanol plant for export production would be constructed on the island. Five miles of onshore pipeline is required in addition to the offshore segment.

Table III-2 — Development Costs for Bul Hanine Field in Qatar
(Million 1988 dollars)

	Input		Calculated	
Field Development for Processing Plant Assumed	Total Reserves per Plant (bcf)	1,050	Project Demands (MMcfd), 15 Years	115.1
Calculations Based on 15-Year Plant Life and Required	Initial Well Production (MMcfd)	22	Project Demands (MMcfd/Year)	42,000
Inlet of 115 MMcfd for 15 Years	Years Flat Production/Well	1		
	Annual Decline Rate per Well	0.111		
Khuff Reservoir:	R/P, Total Project	25	Total bcf/Well (35 Years)	71.2
0.5% H_2S 5.0% CO_2 40 bbl/MMcf Condensate	Discount Rate	0.10	Total Wells Needed	13.4
115-foot water depth 5.0% Gas Plant Liq. Shrink.	Total Reservoir Reserves (bcf)	1,050	PV of Well Timing	0.70
25 miles to Halil Island				
5 miles onshore pipeline				

Field Devel. Phase	No. of Process Plants	No. of prod. wells	No. platf.	No. slots/ platf.	Developed Reserves (bcf)	Cost* per platf.	Total platf. costs	Platf. rig mobil.	Sour gas prod. equip.	PV of net aband.	Gas P/L	Oil P/L	Total exc. D&C	PV of Devel. wells D&C	Gas Plant	Total	Total incl. Ov'hd
1	1	14.0	5.0	8	1,050	6.71	33.5	0.4	24.3	0.5	16 Off 2 Land	7 Off 3 Land	87	76	19	182	274

Phase 1: One processing plant at 115 MMcfd

*Conventional fixed steel-jacket-platform wellhead platforms.
Separate platforms for living quarters, production equipment, and utilities assumed.
Production equipment estimated on a per-platform basis; sour gas equipment costs three times sweet service.

Wells at 1988 cost of $7 million per well.
Number of wells assumes additional wells drilled as required to sustain capacity for 15 years.
Additional costs for dry holes included (15% of development wells assumed to be dry holes).
All fields assume one exploration well re-entered and completed as producer; development cost of this well consists of completion costs.

Overhead 20%, contingency 10%, owner's cost 20% added to total development cost.

<u>U.S. Gulf Coast multipliers</u>
Location equipment-cost multiplier: 1.25
Location platform-cost multiplier: 1.00
Location well-cost multiplier: 1.00
Location pipeline-cost multiplier: 1.00

The present-value cost of completing 14 productive wells is estimated at $76 million (including dry hole allocation). Costs include two dry holes and the completion expenses only for one exploration well completed as a producer. This is based on a cost of $7.0 million per well drilled to the Khuff Reservoir at 12,200 feet (about $575 per foot). Estimated gas plant construction costs are about $19 million, including the cost of additional treatment for the high CO_2 and H_2S content of the gas and an increase of 25 percent for added location expense. Total direct investment costs are $182 million. With overhead, contingencies, and construction financing, total costs rise to $274 million.

Similar analyses of investment costs are made for each field or group of fields covered by this study. Fields are grouped together when significant cost savings could be achieved. In isolated locations with relatively small reserves, the cost of separate pipelines and facilities will make development very expensive. However, all fields with reserves of 100 bcf and greater are included regardless of the costs involved.

IV. DISCOUNTED CASH-FLOW ANALYSIS

OBJECTIVES AND METHODOLOGY

A spreadsheet model was used to perform a discounted cash-flow analysis for each field based on investment cost, operating expenses, annual production estimates, condensate yield, gas plant shrinkage and fuel use, financing assumptions, tax and royalty parameters, expected rate of return on equity, and the value of condensate and NGL's. The key concept in these resource cost calculations is that the present value of total hydrocarbon production retained by the working interest is equal to the present value of all working interest costs including return on equity. The price of liquids production and therefore the revenue gained is assumed constant. The price of gas is allowed to vary so that total revenues satisfy total revenue requirements. Table IV–1 contains the inputs for the economic model for the Bul Hanine Field, Khuff Reservoir. All cost data are in 1989 dollars, estimated by taking the 1988 investment cost estimates and inflating them by 4.0 percent. The following paragraphs outline the steps taken to calculate the dollar-per-Mcf sales gas development cost for each field.

EXAMPLE RESOURCE COST ESTIMATE

Discounted Cash-Flow Methodology

The discounted cash-flow calculations in Tables IV–1 through IV–3 are for the Bul Hanine Field example discussed in the previous sections. The example calculation is based on the following financial parameters, which were kept constant for all fields in the study:

- 15-year project life.
- 40 percent debt financing over a 10-year term at 12 percent nominal interest rate.
- Required nominal return on equity of 20 percent.
- Income taxes calculated in the same manner as in the United States (total government income tax take of 37.3 percent).
- 40 percent royalty burden.
- Condensate and gas plant liquids equal to 90 percent of crude value on a Btu basis ($4.31 per MMBtu).
- Straight-line depreciation of capital investments over the life of the project.
- Inflation rate of 5 percent per year.

The following production and cost parameters were also kept constant for all fields:

- Production rate constant at annual rate equal to 1/25 of initial reserves.
- Overhead and contingencies equal to 50 percent of initial investment.

Table IV–1 summarizes the input fiscal and cost parameters used in the discounted cash-flow analysis. As the summary data indicate, each field is assumed to be taxed as a stand-alone project (ring-fenced). Tax deductions in excess of annual net cash flows are carried forward.

The first set of calculations uses nominal dollars (Table IV–2). The total capital investment is split into a debt portion (40 percent) and an equity portion (60 percent). Debt payments are calculated and split into principal repayment and interest payment portions for tax purposes. Annual nominal debt payments are $20.1 million per year. A nominal return on equity payment (20 percent) is calculated based on the project life and equity investment and added to each year's required revenue ($36.4 million per year). Annual operating expenses are added to the total costs, with an inflation escalation factor. The tax deductions attributable to the interest payments on debt and depreciation are calculated.

Total annual costs that must be met by the working interest share of production are the sum of total debt payments, equity return, operating expenses, income taxes, and any special petroleum taxes such as excise taxes (none are assumed in this example). At this point the model uses iterative calculations to estimate the gas price required to meet all of the working interest requirements on a

Table IV-1 — Resource Cost Calculation for Natural Gas Development Project in Bul Hanine Field, Khuff Reservoir In Qatar

Economic Parameters		Production, Costs	
Equity Ratio	0.60	Total Raw Reserves (bcf)	1,050
Nominal Return on Equity (%)	20.0	Daily Prod. Cap. (Raw MMcfd)	115
		Nonhydrocarbon Gases (%)	5.5
Debt Ratio	0.40	Condensate (bbl/MMcf)	40
Nominal B.T. Debt Interest (%)	12.0	Gas Plant Conversion to Liquids (%)	5.0
Debt Term (years)	10	L&P Fuel Gas Use, Inc. PL (%)	2.5
Income Tax Rate	0.37	Platform Costs ($MM)	35.3
Nominal A.T. Cost of Capital (%)	15.0	Equipment Costs ($MM)	25.3
Real A.T. Cost of Capital (%)	9.5	Gas Pipeline Costs ($MM)	18.7
		Condensate Pipeline Costs ($MM)	10.4
Depreciation Period (years)	15	Artificial Island Costs ($MM)	0.0
Inflation (%)	5.0	Overhead Costs ($MM)	94.5
		Gas Plant Costs ($MM)	19.8
Utilization Rate (%)	95.0	Abandonment Costs, Pr. Value ($MM)	0.5
Investment Life (years)	15		
		Well Costs, Pr. Value ($MM)	79.0
Overhead Rate (%)	50	Total Number of Wells	14
Government Royalty (%)		Total Capital, w/OVHD (1989 $MM)	283
Before Payout	40.0	Debt	113
After Payout	40.0	Equity	170
Value of Crude, Cond. ($/bbl)	27.80	Annual O&M (1989 $MM)	5.5
Value of Plant Liquids ($/MMBtu)	4.31	Annual O&M = 5% of Plant/Pipeline Capital Costs,	
		+ 1.5% of Artificial Island Costs,	
Initial R/P (years)	25	+ $40m/Well Onshore, $125m/Well Offshore,	
		$1,500m/Well arctic	
		Well Decline Rate (%/yr)	11.1

Note: Project is located offshore, with water depth of 115 feet.

m=1,000.

Table IV-2 — After-Tax Project Costs for Bul Hanine Field, Khuff Reservoir in Qatar
(Nominal million dollars)

	Debt						Taxes							
Year	Balance	Payment (C)	Princip.	Interest (E)	Equity Return (F)	Annual O&M (G)	Deprec. (H)	Annual Taxable Income (P-E-G-H)	Tax Losses Incurred	Tax Losses Realized	Losses Carried Over	Adjusted Taxable Income	Income Taxes Paid (N)	Total Costs (C+F+G+N)
1	113.4	20.1	6.5	13.6	36.4	5.5	18.9	21.8	0.0	0.0	0.0	21.8	8.1	70.1
2	106.9	20.1	7.2	12.8	36.4	5.8	18.9	25.3	0.0	0.0	0.0	25.3	9.4	71.7
3	99.7	20.1	8.1	12.0	36.4	6.1	18.9	29.0	0.0	0.0	0.0	29.0	10.8	73.3
4	91.6	20.1	9.1	11.0	36.4	6.4	18.9	32.9	0.0	0.0	0.0	32.9	12.3	75.1
5	82.5	20.1	10.2	9.9	36.4	6.7	18.9	37.2	0.0	0.0	0.0	37.2	13.9	77.0
6	72.3	20.1	11.4	8.7	36.4	7.0	18.9	41.7	0.0	0.0	0.0	41.7	15.5	79.0
7	60.9	20.1	12.8	7.3	36.4	7.4	18.9	46.5	0.0	0.0	0.0	46.5	17.3	81.2
8	48.2	20.1	14.3	5.8	36.4	7.8	18.9	51.7	0.0	0.0	0.0	51.7	19.3	83.5
9	33.9	20.1	16.0	4.1	36.4	8.1	18.9	57.2	0.0	0.0	0.0	57.2	21.3	85.9
10	17.9	20.1	17.9	2.1	36.4	8.6	18.9	63.1	0.0	0.0	0.0	63.1	23.5	88.5
11	(0.0)	0.0	0.0	(0.0)	36.4	9.0	18.9	69.5	0.0	0.0	0.0	69.5	25.9	71.3
12	(0.0)	0.0	0.0	(0.0)	36.4	9.4	18.9	73.9	0.0	0.0	0.0	73.9	27.6	73.4
13	(0.0)	0.0	0.0	(0.0)	36.4	9.9	18.9	78.6	0.0	0.0	0.0	78.6	29.3	75.6
14	(0.0)	0.0	0.0	(0.0)	36.4	10.4	18.9	83.4	0.0	0.0	0.0	83.4	31.1	77.9
15	(0.0)	0.0	0.0	(0.0)	36.4	10.9	18.9	88.5	0.0	0.0	0.0	88.5	33.0	80.3
Total			113.4		546	119	283	800	0	0	*	800	298	1,164
Present Value														443

*Tax losses that cannot be offset by project revenue are allowed to accumulate.

Table IV-3 — Costs, Revenue Flowstreams, and Production Flowstreams for Bul Hanine Field, Khuff Reservoir in Qatar

(Real 1989 dollars)

Year	Real Total Costs ($ million)	Real Required Working Int. Revenue* ($ million)	Production (bcf /Year) Total	Production Royalty	Production Working Interest	Resource Cost ($/Mcf Raw)	Required Project Revenues ($ million) Total	Required Project Revenues Royalty	Required Project Revenues Working Interest	Allocation of W.I. Share ($ million) Real Income Taxes	Real O&M	Real Debt Payment	Rev. After Inc. Tax, Int., & O&M
1	70.1	59.5	39.9	16.0	23.9	2.49	99.2	39.7	59.5	8.1	5.5	13.6	32.5
2	68.2	59.5	39.9	16.0	23.9	2.49	99.2	39.7	59.5	9.0	5.5	12.2	33.1
3	66.5	59.5	39.9	16.0	23.9	2.49	99.2	39.7	59.5	9.8	5.5	10.8	33.6
4	64.9	59.5	39.9	16.0	23.9	2.49	99.2	39.7	59.5	10.6	5.5	9.5	34.2
5	63.4	59.5	39.9	16.0	23.9	2.49	99.2	39.7	59.5	11.4	5.5	8.1	34.7
6	61.9	59.5	39.9	16.0	23.9	2.49	99.2	39.7	59.5	12.2	5.5	6.8	35.3
7	60.6	59.5	39.9	16.0	23.9	2.49	99.2	39.7	59.5	12.9	5.5	5.5	35.9
8	59.3	59.5	39.9	16.0	23.9	2.49	99.2	39.7	59.5	13.7	5.5	4.1	36.5
9	58.2	59.5	39.9	16.0	23.9	2.49	99.2	39.7	59.5	14.4	5.5	2.8	37.1
10	57.1	59.5	39.9	16.0	23.9	2.49	99.2	39.7	59.5	15.2	5.5	1.4	37.7
11	43.8	59.5	39.9	16.0	23.9	2.49	99.2	39.7	59.5	15.9	5.5	-0.0	38.4
12	42.9	59.5	39.9	16.0	23.9	2.49	99.2	39.7	59.5	16.1	5.5	-0.0	38.1
13	42.1	59.5	39.9	16.0	23.9	2.49	99.2	39.7	59.5	16.3	5.5	-0.0	37.9
14	41.3	59.5	39.9	16.0	23.9	2.49	99.2	39.7	59.5	16.5	5.5	-0.0	37.8
15	40.6	59.5	39.9	16.0	23.9	2.49	99.2	39.7	59.5	16.7	5.5	-0.0	37.6
Total	841	897	599	239	359		1,494	598	897	199	83	75	540
Present Value	465	465	312	125	187		778	311	467	95	43	53	276
						$/Mcf Raw Gas Prod.	2.49	1.00	1.50	0.30	0.14	0.17	0.88
						$/Mcf Gas and Liquid Sales	2.86	1.14	1.71	0.35	0.16	0.20	1.01
							100.0%	40.0%	60.0%	12.2%	5.5%	6.8%	35.4%

Table IV–3 — Costs, Revenue Flowstreams, and Related Production Flowstreams for Bul Hanine Field, Khuff Reservoir in Qatar (continued)

(Real 1989 dollars)

Annual Balances		Production Volumes	Required Revenues ($ million)	Required Revenues ($/Mcf)
	Raw Production (bcf)	39.9		
	Non-H.C. Gases (bcf)	2.2		
Gas:	Net H.C. Gases (bcf)	37.7		
	Plant Shrinkage (bcf)	1.9		
	L&P Fuel Use (bcf)	0.9		
	Net Natural Gas Sales (bcf)	34.9	47.1	1.35—Final Result ($/Mcf Sales Gas)
Liquids:	Condensate (MMbbl)	1.60		Sales Gas/Raw Gas: 0.874 (Ratio)
	Condensate (Btu 10^{12})	7.37		
	Plant Liquid (Btu 10^{12})	4.71		
	Total NGL's (Btu 10^{12})	12.09	52.1	1.50 ($/Mcf Equiv. Liquids)
	Total Hydrocarbons:		99.2	2.86

Notes: Calculated PV Costs equal PV Rev. Totals do not add because of rounding.

*Required working interest revenue is levelized.

real-dollar basis. Iterative calculations are necessary because of the interrelationship of revenue, taxes, and tax carry-forwards. The gross revenue received each year by the working interest (last column on Table IV–2) is the nominal dollar equivalent of the annualized real dollar revenue stream generated by the field's production. Annual income taxes are calculated based on this nominal dollar revenue flowstream.

Working interest total annual costs, however, may not coincide with the revenue generated by the project. The model solves for the gas price that allows the real-dollar present value of working interest revenues to equal the real-dollar present value of all costs. Thus, the second column from the right end of Table IV–2 represents the sum of all working interest costs. The present value of the sum of these costs is equal to the required revenue for the working interest owners—$443 million in discounted nominal dollars.

The nominal working interest costs are converted to real dollars, and the real dollar revenue is levelized to 15 equal annual revenue values.[1] Table IV–3 contains the real (1989) dollar costs and annualized revenue flowstreams in the first two columns on the left. The related production flowstreams follow in the next four columns. The annual production kept by the working interests must be sold at a price sufficient to satisfy the annual required revenue for the project.

The calculated annual required real revenue for the Khuff Reservoir is $59.5 million for the working interests. If annual production is 39.9 bcf (115 MMcfd at a 95-percent utilization factor), the working interests must recover their costs from their 60-percent share, 23.9 bcf. The present value of the total working interest production flowstream (187 bcf) is divided into the present value of the working interest total project costs ($465 million) to estimate the raw gas revenue requirement. Thus, required revenue is $2.49 per Mcf of raw gas production. Note that in this example the working interests pay taxes only on their share of production (royalties are deductible), and there is no additional special tax on petroleum. If either of these were applicable, the required working interest revenue would be increased and the calculated hydrocarbon resource cost would increase accordingly.

Total project revenues are assumed to be equal to the working-interest-required-revenue-per-Mcf times field total production. Including the $39.7 million needed for royalty payments, total revenue needs are $99.2 million per year.

The remainder of Table IV–3 depicts the allocation of the working interest share of revenues. Total annual levelized revenues of $59.5 million are paid out in taxes, operating expenses, and for debt interest and principal payments. The remainder is the equity return each year. In this example, the working interests retain about 48 percent of total gross revenues after taxes and royalties.

Sales Gas Required Revenue After Processing

One further calculation is required to account for the value of condensate and plant liquids. Total condensate production each year from the Khuff Reservoir is estimated to be 1.60 million barrels (MMB), while plant liquids are estimated to be about 4,740 MMBtu. Plant liquids are assumed to contain 2,500 Btu per cubic foot of gas. Condensates are assumed to contain about 4.62 MMBtu per barrel. On a Btu-equivalent basis, a total of 12,090 MMBtu of condensate and plant liquids are produced annually with the 39.9 bcf per year of raw gas.

In the United States, condensate is usually valued the same as similar crude oils on a per-barrel basis. Prices of gas plant liquids are much more volatile with respect to crude price parity. In recent years, ethane and propane have generally sold at a discount to crude, while heavier NGL's have sold at a premium to crude on a Btu-equivalent basis. If sold to a refiner in the United States, a weighted average mix of condensate and gas plant liquids has a value somewhat higher than crude oil. The United States, however, has a highly developed market for NGL's and is not representative of other markets lacking petrochemical industries and good transportation infrastructure. For the purposes of this analysis, it is assumed that production of all associated liquids has a value equal to 90 percent of crude

[1]The calculations are done in an iterative process to take into account the interdependence of the tax calculations and the revenue calculations.

at the wellhead, about $4.31 per MMBtu if crude prices are $27.80 per barrel (at 5.8 MMBtu per barrel). The total revenue received for liquids from the Khuff Reservoir example each year amounts to $52.1 million. Liquids revenue is subtracted from total required revenue, $99.2 million, to arrive at the required revenue that must come from gas sales: $47.1 million.

The Khuff gas is estimated to contain 5.5 percent nonhydrocarbon gases, and gas plant shrinkage due to liquids extraction is about 5.0 percent. An additional 2.5 percent of the net hydrocarbon residue gas is consumed by fuel use. Annual production totals 39.9 bcf of raw gas. After removal of nonhydrocarbon gases, 37.7 bcf remains. Shrinkage and fuel use reduces the amount of residue (sales) gas to 34.9 bcf per year. If the required revenue from sales gas is $47.1 million, then the gas must be sold at $1.35 per Mcf. This is the estimated cost of sales gas from the field as well as the cost of the feedstock to a methanol or liquefaction plant. The dollars-per-Mcf cost is shown in the supply-cost curves shown in section 5.

GAS RESOURCE COST SENSITIVITIES

The gas resource costs calculated in this report are based on a single standard fiscal regime and financing arrangement for all fields in all countries. The gas resource cost is the real-dollar price for sales gas over the life of the project that allows the working interests to achieve the present value of their total revenue requirements over the life of the project.

Table IV–4 summarizes the results of several alternative financing assumptions on the calculated resource cost. An offshore field with reserves of 1.7 tcf and total development costs of $498 million (1989 dollars) is used in the example.

Case A is the gas cost without government takes and without financing costs or discounting. This case is shown as a point of reference for illustrating the added costs of financing and taxes. In this case, required revenue per Mcf of total hydrocarbons produced is $0.81. After accounting for liquids revenue, sales gas must receive $0.33 per Mcf. Even with the moderate condensate and plant liquid production attributed to this field, the revenue gained from the sale of liquids reduces the resource cost of gas sales by $0.48 per Mcf. This value is the same in all of the examples shown in Table IV–4 run with a crude oil price of $27.80.

Case B uses the standard set of assumptions for equity and debt financing, government takes, and inflation. At a real average cost of capital of 9.5 percent, required sales gas revenue is $2.53 per Mcf.

Case C was run with 100 percent equity and 20 percent nominal return, which increases the real average cost of capital to 14.3 percent. Required sales gas revenue is now $3.36 per Mcf.

Case D assumes 100 percent equity financing again, but with a higher required return. The 30-percent nominal return on equity in this case might be applied by an investor that believes the project entails greater risk than the investor in Case C. The 50-percent increase in equity return from Case C results in an 8-percent increase in sales gas costs (from $3.36 per Mcf to $3.68 per Mcf).

Case E returns to the standard financing assumptions in Case B, but with investment and operating costs increased 10 percent. Sales gas resource costs increase 12 percent in this case, to $2.83 per Mcf.

Case F assumes the standard financing assumptions as in B, but eliminates the before-tax royalty payment to the state. The additional 40 percent of production that reverts to the working interests lowers the gas resource cost to $1.32 per Mcf.

Case G resumes royalty payments, but assumes no income taxes are paid. In this case, gas resource costs only drop to $2.02 per Mcf.

Case H uses the standard set of fiscal assumptions, but a lower liquids value. In this case, $20.00 per barrel crude oil prices were assumed. The liquids value contribution drops from $0.48 per Mcf in Case B to $0.35 per Mcf in Case H. This illustrates the importance of liquids production in most of the fields in this study. The revenue required from gas sales increases $0.13 per Mcf as the revenue from liquids decreases $0.13 per Mcf. The field used in these examples has only moderate liquids

Table IV–4 — Effects of Fiscal and Financial Assumptions and Production Rates on Example Resource Cost Calculations

Example Field: Pagerungan, Indonesia (EUR 1.7 tcf)
Condensate Yield 8 bbl/MMcf, Nonhydrocarbons 3.0%, NGL Shrinkage 2.7%

Base Parameters: 1989 Capital Cost of Development, Including Overhead: $498MM
15-Year Project Life, Initial R/P Ratio = 25

Input Parameters: Case		Debt Portion (%)	Debt Rate (%)	Equity Return (%)	Income Tax (%)	Nominal Cost of Capital (%)	Annual Future Inflation (%)	Real Cost of Capital (%)	Royalty (%)	Liquids Value $/MMBtu	$/Mcf Sales Gas Excl. Liquids Value	$/Mcf Sales Gas w/ Liquids Value Acct'd For
A	0 Gov't Take, 0 Discount Rate	0	0	0	0.0	0.0	0.0	0.0	0	4.31	0.81	0.33
B	Tax, Royalty, Financing Costs	40	12	20	37.3	15.0	5.0	9.5	40	4.31	3.01	2.53
C	100% Equity, 20% Return	0	0	20	37.3	20.0	5.0	14.3	40	4.31	3.84	3.36
D	100% Equity, 30% Return	40	12	30	37.3	21.0	5.0	15.2	40	4.31	4.11	3.62
E	As B, Investment Increased 10%	40	12	20	37.3	15.0	5.0	9.5	40	4.31	3.31	2.83
F	As B, 0 Royalty	40	12	20	37.3	15.0	5.0	9.5	0	4.31	1.81	1.32
G	As B, 0 Income Tax	40	12	20	0.0	16.8	5.0	11.2	40	4.31	2.50	2.02
H	As B, Lower Liquids Value	40	12	20	37.3	15.0	5.0	9.5	40	3.10	3.01	2.66
I	As B, 25-Year Project Life	40	12	20	37.3	15.0	5.0	9.5	40	4.31	2.85	2.36
J	As B, Initial R/P Ratio = 15	40	12	20	37.3	15.0	5.0	9.5	40	4.31	1.94	1.46

Notes: Variations From Standard Case B
All cases except C and D assume debt financing, 20 percent nominal ROE.
All cases except I and J assume 15-year project life, initial R/P ratio = 25.
All cases except F assume liquids value based on crude oil value of $27.80 per barrel (Case F at $20 per barrel).
All cases except E assume $498 million investment (Case E $547 million).

production, yet the revenue gained from liquids is 16 percent of the total project revenues in the standard case (Case B, $0.48/ $3.01 = .16). The relative impact of liquids revenues and price assumptions varies with individual fields. Many fields in this report have high liquids yield, and their resource costs estimates are even more sensitive to changes in oil price assumptions than the example shown here.

Case I returns to the standard assumptions as in Case B but assumes a longer project life. Ten years are added in which the field is allowed to produce at a declining rate and the working interests may use the additional production to satisfy their investment and equity return requirements. Sales gas costs drop to $2.36 per Mcf, a 7-percent reduction from Case B.

Case J illustrates the effect of increasing production rates. Case J assumes production rates are increased by 66 percent in the first few years of the project (initial R/P ratio reduced from 25 to 15). The field plateau production rate now lasts 10 years rather than 15. In this case, the present-value equivalent of cumulative field production during the project life increases from 505 bcf in Case B to 783 bcf in Case J. Required sales gas revenue decreases to $1.46 per Mcf, a 42-percent reduction from Case B. This result is not quite accurate because costs would increase somewhat as wells would be drilled earlier in the project life and the size of production and processing equipment would have to be increased. However, the increased investment would not be great enough to eliminate all of the large reduction in resource costs in the example calculation.

OPPORTUNITY COSTS

In some instances, the resource cost calculations made in this report yield a low or negative value for sales gas. This typically occurs for gas fields with high volumes of condensate and plant liquids, which can bear most or all of the development and operating costs for the field. In such instances, a floor price of $0.25 per Mcf has been applied to account for the future opportunity costs of the gas.

The calculation of future opportunity costs for the gas is a subjective matter that depends critically on what assumptions one makes about the potential future markets for the gas. The key elements in the calculation are the following:

- When will a market for the gas occur?
- What price will the gas receive?
- How will field development and operating costs change if gas sales from the field are delayed?
- What risk (discount) factor should be applied in assessing opportunity costs?
- From whose perspective is the opportunity cost to be evaluated, that is, the working interests or the host country?

Tables IV–5 and IV–6 show two examples of an opportunity cost calculation for a field with a net sales gas resource cost of -$0.20 per Mcf, which derives from a basic cost of $0.80 per Mcf less liquids revenue of $1.00 per Mcf. The simplified examples represent one unit of production per year in which tax effects are ignored and gross revenue is split 50:50 between working interests and the government. The assumptions used for Table IV–5 are the following:

- The field will be developed in Year 1 to produce liquids no matter what is done with the dry gas.
- The first option (left side of the table) is to delay dry gas sales until the 21st year, when it is hypothesized that a market will exist for the gas at a price of $2.88 per Mcf. This price is 60 percent of the projected year-2000 oil price on a heating value basis.
- Delaying gas sales will *not* affect operating and development costs for the field.
- The real after-tax discount rate used in the evaluation of opportunity costs is 9.5 percent, the same as used in the original resource cost calculation.

The result is a calculated opportunity cost of $0.47 per Mcf, that is, the price the gas must receive if sold starting in Year 1, such that the net present value of the project is the same

Table IV–5 — Illustration of Opportunity Cost: Ignoring Extra Costs for Delayed Gas Sales

Added Cost to Reinject:	$0.00 /Mcf Sales Gas	Oil Price in Year 2000:	$27.80/bbl
Added Cost to Operate Year 21+:	$0.00/Mcf Sales Gas	Gas-Oil Price Ratio:	0.60
		Hypothesized Future Gas Price:	$2.88/Mcf Sales Gas
Discount Rate:	9.50% Real, After Tax	Gross Resource Cost:	$0.80/Mcf Sales Gas (No liquids credit)
State Split of Gross Rev.:	0.50	Cost to Working Interest:	$0.40/Mcf Sales Gas (No liquids credit)
		Liquids Value:	$1.00/Mcf Sales Gas
		Net Resource Cost:	($0.20)/Mcf Sales Gas (With liquids credit)

	Option 1: Gas Sales Delayed 20 Years ($/Mcf)							Option 2: Gas Sales Start in Year 1 ($/Mcf)						
			Working Interest							Working Interest				
	Total Gas Rev.	Total Liq. Rev.	Rev.	Cost	Net Rev.	State Rev.	Total Net Rev.	Total Gas Rev.	Total Liq. Rev.	Rev.	Cost	Net Rev.	State Rev.	Total Net Rev.
NPV:	3.67	7.83	5.75	(3.13)	2.62	5.75	8.36	3.67	7.83	5.75	(3.13)	2.62	5.75	8.36
Year														
1	0.00	1.00	0.50	(0.40)	0.10	0.50	0.60	0.47	1.00	0.73	(0.40)	0.33	0.73	1.07
2	0.00	1.00	0.50	(0.40)	0.10	0.50	0.60	0.47	1.00	0.73	(0.40)	0.33	0.73	1.07
3	0.00	1.00	0.50	(0.40)	0.10	0.50	0.60	0.47	1.00	0.73	(0.40)	0.33	0.73	1.07
4	0.00	1.00	0.50	(0.40)	0.10	0.50	0.60	0.47	1.00	0.73	(0.40)	0.33	0.73	1.07
5	0.00	1.00	0.50	(0.40)	0.10	0.50	0.60	0.47	1.00	0.73	(0.40)	0.33	0.73	1.07
6	0.00	1.00	0.50	(0.40)	0.10	0.50	0.60	0.47	1.00	0.73	(0.40)	0.33	0.73	1.07
7	0.00	1.00	0.50	(0.40)	0.10	0.50	0.60	0.47	1.00	0.73	(0.40)	0.33	0.73	1.07
8	0.00	1.00	0.50	(0.40)	0.10	0.50	0.60	0.47	1.00	0.73	(0.40)	0.33	0.73	1.07
9	0.00	1.00	0.50	(0.40)	0.10	0.50	0.60	0.47	1.00	0.73	(0.40)	0.33	0.73	1.07
10	0.00	1.00	0.50	(0.40)	0.10	0.50	0.60	0.47	1.00	0.73	(0.40)	0.33	0.73	1.07
11	0.00	1.00	0.50	(0.40)	0.10	0.50	0.60	0.47	1.00	0.73	(0.40)	0.33	0.73	1.07
12	0.00	1.00	0.50	(0.40)	0.10	0.50	0.60	0.47	1.00	0.73	(0.40)	0.33	0.73	1.07
13	0.00	1.00	0.50	(0.40)	0.10	0.50	0.60	0.47	1.00	0.73	(0.40)	0.33	0.73	1.07
14	0.00	1.00	0.50	(0.40)	0.10	0.50	0.60	0.47	1.00	0.73	(0.40)	0.33	0.73	1.07
15	0.00	1.00	0.50	(0.40)	0.10	0.50	0.60	0.47	1.00	0.73	(0.40)	0.33	0.73	1.07
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21	2.88	0.00	1.44	0.00	1.44	1.44	2.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	2.88	0.00	1.44	0.00	1.44	1.44	2.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	2.88	0.00	1.44	0.00	1.44	1.44	2.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	2.88	0.00	1.44	0.00	1.44	1.44	2.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table IV–5 — Illustration of Opportunity Cost: Ignoring Extra Costs for Delayed Gas Sales (continued)

	Option 1: Gas Sales Delayed 20 Years ($/Mcf)							Option 2: Gas Sales Start in Year 1 ($/Mcf)						
			Working Interest							Working Interest				
Year	Total Gas Rev.	Total Liq. Rev.	Rev.	Cost	Net Rev.	State Rev.	Total Net Rev.	Total Gas Rev.	Total Liq. Rev.	Rev.	Cost	Net Rev.	State Rev.	Total Net Rev.
25	2.88	0.00	1.44	0.00	1.44	1.44	2.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00
26	2.88	0.00	1.44	0.00	1.44	1.44	2.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	2.88	0.00	1.44	0.00	1.44	1.44	2.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00
28	2.88	0.00	1.44	0.00	1.44	1.44	2.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29	2.88	0.00	1.44	0.00	1.44	1.44	2.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30	2.88	0.00	1.44	0.00	1.44	1.44	2.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00
31	2.88	0.00	1.44	0.00	1.44	1.44	2.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32	2.88	0.00	1.44	0.00	1.44	1.44	2.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33	2.88	0.00	1.44	0.00	1.44	1.44	2.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34	2.88	0.00	1.44	0.00	1.44	1.44	2.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00
35	2.88	0.00	1.44	0.00	1.44	1.44	2.88	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Note: Field developed in Year 1 for NGL production.

Table IV–6 — Illustration of Opportunity Cost: Considering Extra Costs for Delayed Gas Sales

Added Cost to Reinject:	$0.20/Mcf Sales Gas	Oil Price in Year 2000:	$27.80/bbl
Added Cost to Operate Year 21+:	$0.10/Mcf Sales Gas	Gas-Oil Price Ratio:	0.60
		Hypothesized Future Gas Price:	$2.88/Mcf Sales Gas
Discount Rate:	9.50% Real, After Tax	Gross Resource Cost:	$0.80/Mcf Sales Gas (No liquids credit)
State Split of Gross Rev.:	0.50	Cost to Working Interest:	$0.40/Mcf Sales Gas (No liquids credit)
		Liquids Value:	$1.00/Mcf Sales Gas
		Net Resource Cost:	($0.20)/Mcf Sales Gas (With liquids credit)

	Option 1: Gas Sales Delayed 20 Years ($/Mcf)							Option 2: Gas Sales Start in Year 1 ($/Mcf)						
			Working interest							Working Interest				
	Total Gas Rev.	Total Liq. Rev.	Rev.	Cost	Net Rev.	State Rev.	Total Net Rev.	Total Gas Rev.	Total Liq. Rev.	Rev.	Cost	Net Rev.	State Rev.	Total Net Rev.
NPV:	3.67	7.83	5.75	(4.82)	0.92	5.75	6.67	1.97	7.83	4.90	(3.13)	1.77	4.90	6.67
Year														
1	0.00	1.00	0.50	(0.60)	(0.10)	0.50	0.40	0.25	1.00	0.63	(0.40)	0.23	0.63	0.85
2	0.00	1.00	0.50	(0.60)	(0.10)	0.50	0.40	0.25	1.00	0.63	(0.40)	0.23	0.63	0.85
3	0.00	1.00	0.50	(0.60)	(0.10)	0.50	0.40	0.25	1.00	0.63	(0.40)	0.23	0.63	0.85
4	0.00	1.00	0.50	(0.60)	(0.10)	0.50	0.40	0.25	1.00	0.63	(0.40)	0.23	0.63	0.85
5	0.00	1.00	0.50	(0.60)	(0.10)	0.50	0.40	0.25	1.00	0.63	(0.40)	0.23	0.63	0.85
6	0.00	1.00	0.50	(0.60)	(0.10)	0.50	0.40	0.25	1.00	0.63	(0.40)	0.23	0.63	0.85
7	0.00	1.00	0.50	(0.60)	(0.10)	0.50	0.40	0.25	1.00	0.63	(0.40)	0.23	0.63	0.85
8	0.00	1.00	0.50	(0.60)	(0.10)	0.50	0.40	0.25	1.00	0.63	(0.40)	0.23	0.63	0.85
9	0.00	1.00	0.50	(0.60)	(0.10)	0.50	0.40	0.25	1.00	0.63	(0.40)	0.23	0.63	0.85
10	0.00	1.00	0.50	(0.60)	(0.10)	0.50	0.40	0.25	1.00	0.63	(0.40)	0.23	0.63	0.85
11	0.00	1.00	0.50	(0.60)	(0.10)	0.50	0.40	0.25	1.00	0.63	(0.40)	0.23	0.63	0.85
12	0.00	1.00	0.50	(0.60)	(0.10)	0.50	0.40	0.25	1.00	0.63	(0.40)	0.23	0.63	0.85
13	0.00	1.00	0.50	(0.60)	(0.10)	0.50	0.40	0.25	1.00	0.63	(0.40)	0.23	0.63	0.85
14	0.00	1.00	0.50	(0.60)	(0.10)	0.50	0.40	0.25	1.00	0.63	(0.40)	0.23	0.63	0.85
15	0.00	1.00	0.50	(0.60)	(0.10)	0.50	0.40	0.25	1.00	0.63	(0.40)	0.23	0.63	0.85
16	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
17	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
18	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
19	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
21	2.88	0.00	1.44	(0.10)	1.34	1.44	2.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00
22	2.88	0.00	1.44	(0.10)	1.34	1.44	2.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00
23	2.88	0.00	1.44	(0.10)	1.34	1.44	2.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00
24	2.88	0.00	1.44	(0.10)	1.34	1.44	2.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Table IV–6 — Illustration of Opportunity Cost: Considering Extra Costs for Delayed Gas Sales (continued)

	Option 1: Gas Sales Delayed 20 Years ($/Mcf)							Option 2: Gas Sales Start in Year 1 ($/Mcf)						
			Working Interest							Working Interest				
Year	Total Gas Rev.	Total Liq. Rev.	Rev.	Cost	Net Rev.	State Rev.	Total Net Rev.	Total Gas Rev.	Total Liq. Rev.	Rev.	Cost	Net Rev.	State Rev.	Total Net Rev.
25	2.88	0.00	1.44	(0.10)	1.34	1.44	2.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00
26	2.88	0.00	1.44	(0.10)	1.34	1.44	2.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00
27	2.88	0.00	1.44	(0.10)	1.34	1.44	2.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00
28	2.88	0.00	1.44	(0.10)	1.34	1.44	2.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00
29	2.88	0.00	1.44	(0.10)	1.34	1.44	2.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00
30	2.88	0.00	1.44	(0.10)	1.34	1.44	2.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00
31	2.88	0.00	1.44	(0.10)	1.34	1.44	2.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00
32	2.88	0.00	1.44	(0.10)	1.34	1.44	2.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00
33	2.88	0.00	1.44	(0.10)	1.34	1.44	2.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00
34	2.88	0.00	1.44	(0.10)	1.34	1.44	2.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00
35	2.88	0.00	1.44	(0.10)	1.34	1.44	2.78	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Note: Field developed in Year 1 for NGL production.

($8.36). Note the net present value to the working interest ($2.62) and that to the government ($5.75) are identical under the two options. This is because the costs of the project have not been changed.

The opportunity cost in this first example is simply the hypothesized future price discounted back to Year 1:

$$\$0.47 = \$2.88 / (1.095)^{20}$$

Assuming that the market for the gas would not start until Year 31, the opportunity cost would be:

$$\$0.19 = \$2.88 / (1.095)^{30}$$

Assuming that risks of the existence of the hypothesized gas market 20 years into the future warrant adding 3 percent to the discount rate, the opportunity cost would be:

$$\$0.27 = \$2.88 / (1.125)^{20}$$

Table IV–6 shows another calculation of opportunity cost, but adds the more realistic assumption that costs will increase because gas must be reinjected for the first 15 years while only liquids are being sold and because the field must be operated for an additional 15 years while the dry gas is being sold. An extra cost of $0.20 per Mcf is added to the first 15 years of operation to account for the cost of injection wells, dry gas pipeline from the gas plant back to the field, and more compression. An extra cost of $0.10 per Mcf is added in years 21 to 35 for continued operation and maintenance of the field. These assumptions lead to an opportunity cost of $0.25 per Mcf. This value can be found as the hypothesized future price discounted back to Year 1, less the increase in costs annualized over 15 years (approximately $0.22 per Mcf in this case):

$$\$0.25 = (\$2.88 / (1.095)^{20}) - 0.22$$

In this second example, the net present value of the project falls from $8.36 to $6.67 because of the extra costs of delaying gas sales. Although this net present value for the project is the same when gas sales are delayed versus when they proceed in Year 1, the allocation between working interest and the government shown in Table IV–5 differs between the two options. The working interest NPV goes from $0.92 to $1.77, while the government's goes from $5.75 to $4.90. This occurs because the simple example ignores tax effects that probably would give the state a higher portion of revenues. Whether the government (or working interest) is disadvantaged between the options will depend on the specifics of the tax and/or production sharing regime in the country. The example is structured such that enough revenue is generated to potentially keep both parties whole.

The theoretical examples shown in Tables IV–5 and IV–6 go out 35 years after the field begins production. In practice, it is possible that neither a private company with a working interest in the project nor the host government would comfortably make a decision to delay gas sales if the justification for the decision depended on revenues that would come between the 21st and 35th years. This may be too far into the unforeseeable future and beyond the career horizons of most executive or government leaders. In such instances, the price floor for the sales gas in practice would be lower than the theoretical opportunity cost.

On the other hand, resource extraction projects, particularly those for export, often are politically sensitive. This leads governments to demand prices for their resources that may be based on notions of "nonexploitation" rather than market value. In these cases, projects may not go ahead even when a price equal to the theoretical opportunity costs is obtainable.

Given the wide range of assumptions one could reasonably make in calculating theoretical opportunity costs and the uncertainty as to how the opportunity costs would be applied in practice, there is no generally agreed-upon way to determine what the price floor should be for the cost curves created in this study. The value of $0.25 per Mcf was selected because it was consistent with some reasonable assumptions, including the examples shown here. Within the Alternative Fuels Trade Model (AFTM), gas prices are solved for based on market value of the gas as well as the gas resource costs calculated here. It is usually the case that the price floor of $0.25 per Mcf is not binding on AFTM results.

V. COUNTRY SUMMARIES

INTRODUCTION

This section contains the supply-cost curves developed for each country in this report. All identified undeveloped nonassociated gas fields with reserves greater than 100 bcf have been included in these curves.

The brief discussion on each country contains some background information about its natural gas industry and characteristics of its largest undeveloped gas deposits.

ABU DHABI

Abu Dhabi has, by far, the largest oil and gas reserves and the greatest political influence within the United Arab Emirates. The first oilfield developed in Abu Dhabi was the Bab (Murban) field, discovered in 1954. The first major offshore discovery was the Umm Shaif field in 1958. Liquefied natural gas plant operations started offshore in 1977. The majority of exploration and production is carried out by the Abu Dhabi National Oil Company (ADNOC).

Most of the nonassociated gas in Abu Dhabi is located in the Khuff formation at 14,000 to 20,000 feet. Other significant accumulations of nonassociated gas are found in the Thamama and Arab formations at 7,000 to 9,000 feet. Hydrocarbon deposits are split equally between offshore and onshore locations, but the newer, nonassociated gas reservoirs included in this study are mostly offshore.

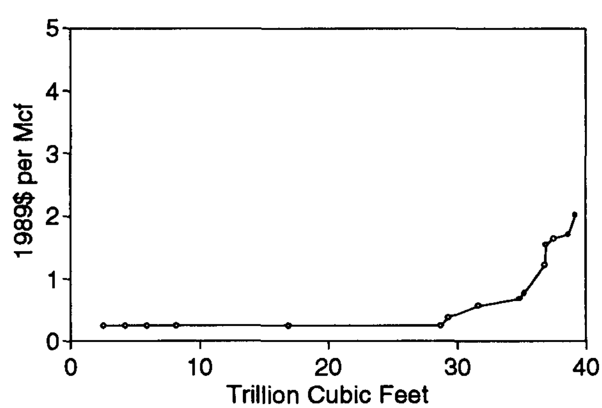
Total undeveloped nonassociated gas reserves in Abu Dhabi have been estimated to be 47.1 tcf in this report. Condensate yields generally are very high, averaging at least 40 barrels per MMcf. Gas plant shrinkage is estimated to be 5.0 percent on average. The shallower formations generally are free of nonhydrocarbon gases, but the Khuff formation contains from 4 percent to 30 percent CO_2, and from 1.5 percent to 6 percent H_2S. However, well productivities are fairly high, ranging up to 50 MMcfd in the Khuff; consequently, calculated sales gas costs are very low.

The Umm Shaif Khuff formation, the largest reservoir included in this study, has undeveloped nonassociated gas reserves estimated at 14.0 tcf, with 11.7 tcf of sales gas that can be developed at virtually no cost. Because of the high liquids production, the resource cost for Umm Shaif sales gas is at the $0.25-per-Mcf minimum.

Other major undeveloped nonassociated gas formations in Abu Dhabi are the Bab field Thamama F formation (10.0 tcf, discovered in 1954), the Saath al Raaz Boot field Khuff formation (3.0 tcf, discovered in 1970), and the Nasr field Khuff formation, (4.0 tcf, discovered in 1971). Most of the fields have oil and associated gas production from other formations. Some nonassociated gas production already is produced for export, or is stripped of condensates and reinjected or flared. Nonassociated gas production from Umm Shaif started in 1979 and from Bab in 1985.

The only adjustment made to Abu Dhabi investments is a 25-percent increase to the cost of production equipment and gas plant construction. Total nonassociated sales gas available from Abu Dhabi is estimated to be about 38.7 tcf, the majority of which is priced below $1.00 per Mcf (Figure V–1).

Figure V–1 — Development Costs of Nonassociated Undeveloped Gas in Abu Dhabi



Note: Year 2000 Oil Price Basis

ALGERIA

Algeria contains large amounts of nonassociated gas that have been developed for Sonatrach's (the state oil and gas company) export program. Algeria is one of the world's largest exporters of LNG. Gas also is exported via pipeline to Europe via the Trans-Mediterranean line to Sicily. This system currently consists of three subsea lines with capacity of 440 bcf per year. Proposals to increase capacity are under study. Algerian LNG exports to the United States recommenced in the late 1980's after renegotiation of pricing terms in contracts with Distrigas and Panhandle. Contracts with British Gas, Turkey, and Greece also have been renegotiated. A proposal with Tunisia and Libya to construct a $400 million pipeline connecting the three countries is being discussed.

Most Algerian fields are located in two major basins: the Reggan Basin, approximately 400 miles south of Hassi R'Mel; and the Pougnac Basin, which extends over a large arc between 70 and 400 miles southeast of Hassi Messaoud.

Sonatrach has outlined plans for large increases in gas liquids production capacity during the 1990's. Foreign operators are being invited to join projects to increase LPG production as well as to conduct exploration programs.

The first major oil and gas discoveries in the country were made in 1956, including the Hassi Messaoud oil field, and the Hassi R'Mel gas field. Virtually all fields are located in the interior Sahara desert, more than 400 miles from the Mediterranean coast. Many gas reservoirs in Algeria produce extremely high condensate volumes, ranging from about 20 to 40 barrels per MMcf up to 700 barrels per MMcf. Hassi R'Mel, Algeria's largest gas field, produces over 75 barrels per MMcf. Relatively low porosities, but high permeabilities, are reported by Petroconsultants in reservoir descriptions. Nonhydrocarbon gas content is relatively low, but shrinkage is fairly high because of the high amount of heavier hydrocarbons in the gas stream. Shrinkage assumed in this study ranges from 1.5 percent to 7.0 percent in various fields. Individual well deliverability is assumed to be from 2.5 MMcfd to 20 MMcfd.

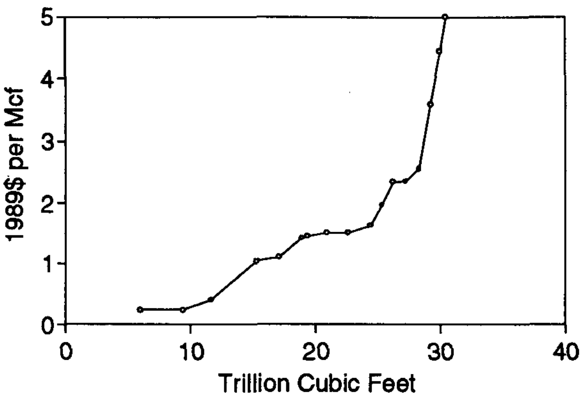
Total undeveloped nonassociated gas reserves in Algeria are estimated in this study at 34.3 tcf. This does not include any Hassi R'Mel gas. The largest gas accumulation included in this study is the Rhourde Nouss field. The field was discovered in 1962 and produces oil and condensate, but a large portion of the gas produced is reinjected into either Rhourde Nouss or Hassi R'Mel. Undeveloped nonassociated gas is estimated to be about 6.5 tcf, with new gas development costs calculated to be zero because of the liquids content. Other major undeveloped nonassociated gas fields included in this report are In Salah (3.5 tcf, discovered in 1958), Hamra (3.5 tcf, discovered in 1959), and Tin Fouye-Tabankort (2.0 tcf, discovered in 1966).

A large portion of the gas from Hassi R'Mel and nearby gas fields is reinjected into Hassi R'Mel to optimize condensate recovery. Since the discovery of Hassi R'Mel, development of numerous other gas discoveries in Algeria has been postponed. Fields that have been developed frequently are piped to the Hassi R'Mel facilities for processing, reinjection, or transportation to the coast. Although fully developed, a large amount of production from Hassi R'Mel is reinjected, and net production is much lower than gross production figures indicate. Hassi R'Mel facilities are designed for total processed production of 7.7 bcfd and as much as 5.8 bcfd of reinjection.

In recent years, facilities for reinjecting associated gas have been constructed for secondary recovery in oil fields. For example, Hassi Messaoud is capable of 1.7 bcfd of gas injection into the field's oil reservoirs. Sources of the injection gas include Hassi Messaoud, Hassi Touareg, Nezla, and Gassi Touil.

Field development costs assume new gas pipelines are laid to Hassi R'Mel and condensate lines are laid to Hassi Messaoud. All of the new developments southeast of Hassi Messaoud are assumed to share in the cost of a common gas trunkline for the 125-mile segment between Hassi Messaoud and Hassi R'Mel. Existing facilities are assumed to carry the gas from Hassi R'Mel to the coast for export (about 350 miles). The only location cost adjustment was a 25-percent increase in production equipment and gas plant construction cost. The 42 fields included in this report

Figure V–2 — Development Costs of Nonassociated Undeveloped Gas in Algeria



Note: Year 2000 Oil Price Basis

were grouped into 17 developments for cost estimates.

Total nonassociated sales gas available from Algeria is estimated to be about 30.4 tcf, the majority of which can be developed for less than $2.00 per Mcf (Figure V–2).

ARGENTINA

Argentina has an established natural gas consumption infrastructure, especially in its larger cities, and the government plans to increase the gas share of energy requirements. The current Argentine government has adopted a policy of encouraging private investments in the petroleum industry—a sharp break from past policies that protected the monopoly of Yacimientos Petroliferos Fiscales (YPF). Major hydrocarbon deposits occur in four basins: San Jorge in the southern province of Santa Cruz; Neuquen, the origin of the oldest production in the country in the central provinces of Neuquen and Rio Negro; Sub-Andean (North-east), lying in the northeastern provinces near Paraguay; and the Austral, which covers a large area onshore and offshore Tierra del Fuego. The largest nonassociated gas field discovered to date is Loma de la Lata (Neuquen Basin), with estimated original recoverable gas reserves of 13.2 tcf. This field was producing at an average rate of more than 870 MMcfd in 1988 and is not included in the inventory of undeveloped fields.

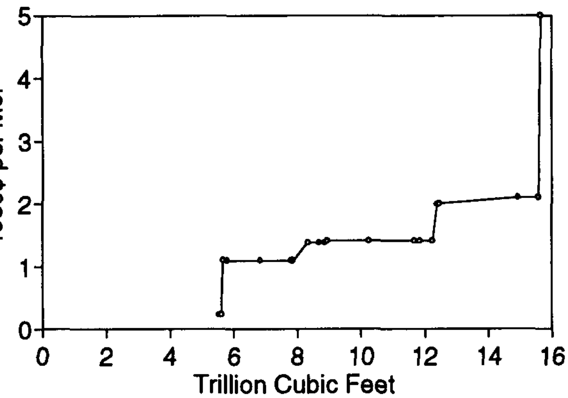
Until the discovery of Loma de la Lata, Argentina obtained most of its gas supplies from associated gas production in oil fields. Since the early 1970's, gas imports from Bolivia have averaged 75 bcf per year. The imports are part of a long-term gas supply contract Argentina entered into to obtain secure supplies for the pipeline grid that already had been created at that time. Demand for gas is estimated to be increasing at more than 15 percent per year, with the government's encouragement.

Although the poor economy of Argentina has delayed gas pipeline expansion and gas export plans, the country's National Energy Plan includes plans for new methanol plants in Tierra del Fuego, and near Buenos Aires. Discussions with Uruguay and Brazil regarding a gas export pipeline continue on an intermittent basis. Argentina already operates large gas processing facilities at Candon Alfa and San Sebastian in Tierra del Fuego, and YPF has plans to accelerate development of its gas reserves.

The producing regions of Argentina encompass a variety of geologic formations, and few generalizations can be made about the country's production characteristics. Most gas reservoirs are shallower than 10,000 feet, and no significant nonhydrocarbon gases are produced along with the gas. Condensate yields vary from less than 10 barrels per MMcf in the Austral Basin to more than 30 barrels per MMcf in the San Jorge. Gas plant shrinkage is 2 or 3 percent. Fields with very high GOR's suspected to contain large gas caps overlying thin oil rims are included in this report as nonassociated gas fields. Many of these types of reservoirs have been found in the offshore Austral Basin, including the Carina, Argo, Aries, Polux, Lobo, Salmon, Vega, and Ara fields. These are recent discoveries, and little production test data have been published. Most wells are not expected to produce more than 15 MMcfd initially. Total undeveloped nonassociated gas reserves in Argentina are estimated in this study at 17.8 tcf.

The largest nonassociated gas accumulations included in the study are in the El Valle field (San Jorge Basin) and the Ramos field (Sub-Andean). Both of these fields have been partially developed for their oil and condensate reserves. Undeveloped nonassociated gas reserves and the cost of gas development are

Figure V–3 — Development Costs of Nonassociated Undeveloped Gas in Argentina



Note: Year 2000 Oil Price Basis

estimated to be 6.0 tcf, $0.25 per Mcf; and 2.7 tcf, $2.11 per Mcf, respectively. The El Valle field actually has a calculated gas development cost of zero because of its high condensate yield. The Ramos field cost is driven by the large pipeline investment assumed in this report. Most Argentine undeveloped reserves are found far from the centers of consumption or possible export locations, so pipeline costs are significant in this study.

Cost adjustments have been made to production equipment, gas plants, and offshore platforms. A 25-percent increase has been added to equipment and gas plants because of the location and infrastructure requirements. A 60-percent increase has been added to offshore platforms because of the remoteness, harsh climate, and seismic risk of the Tierra del Fuego area. Total undeveloped nonassociated sales gas available from Argentina is estimated to be about 15.6 tcf, most of which can be developed for less than $2.00 per Mcf (Figure V–3).

AUSTRALIA

Australian gas production is currently concentrated in several, mostly remote, regions of the continent. Onshore production is located in the interior deserts of South Australia and Queensland in the Cooper Basin, and in the Amadeus Basin of the Northern Territory. Production also continues from the oldest producing area of the country near Roma in Queensland. Offshore exploration has yielded large discoveries of gas in three main areas: the Carnarvon Basin (Northwest Shelf) off Western Australia near Barrow Island and Daupier; the Gippsland Basin in the Bass Strait-Tasman Sea area; and the Timor Sea, part of which is in the disputed Timor Gap area. All of the basins mentioned above are made up of sandstone sediments.

Commercial production of oil and gas did not start in Australia until the early 1960's, mainly because of the extremely remote locations of the onshore fields. Production increased rapidly after 1969 with the development of oil and gas fields in the Bass Strait area. Onshore Australian fields tend to be small accumulations with low flowrates. However, because they occur in large numbers in just a few basins, the majority of them have been developed. The Bass Strait fields have been developed because of their proximity to the large cities of Australia's southeast and much higher productivity. The large discoveries of the Northwest Shelf and Timor Sea have been developed more slowly because of the lack of a nearby market. Currently, the majority of domestic oil production is from the Bass Strait fields.

The Northwest Shelf and Timor Sea areas contain large amounts of gas, which are being developed for local domestic use and for export. Together, these two areas hold 80 percent of the known gas reserves in Australia. Both areas are several thousand miles from the main consuming areas of Australia, and the export of gas as LNG to Japan, Taiwan, and Korea is an economic development alternative. The Burrup Peninsula LNG plant came on-line in June 1989 and is now capable of processing 16,000 cubic meters per day of gas (560 MMcfd). Expansion to 900 MMcfd is planned with the completion of the third LNG train. The North Rankin 'A' platform is the source of gas for this project. A second LNG plant on Burrup Peninsula is also being considered. Increased LNG demand will be supplied by expansion of the North Rankin field and development of Goodwyn and Gordon fields.

More prospective areas in the Timor Sea will soon be explored now that a production sharing agreement with Indonesia has been approved. The agreement will cover a disputed deepwater area surrounded by the discoveries in Australian waters. The first gas fields likely to be developed in the Timor Sea area are the Tern and Petrel discoveries, which lie about 120 miles offshore Darwin. The southwest region of the Timor Sea contains some of the largest undeveloped gas discoveries, including Scott Reef and Brecknock, but these fields lie in waters up to 1,600 feet deep. Broome City, the closest onshore location with some oil infrastructure, is about 250 miles south.

The oil and gas industry in Australia is conducted entirely by private companies, while domestic gas sales and pipeline transmission is conducted or regulated by utilities in much the same manner as in the United States. Dramatic changes in government pricing regulations and royalty rates have taken place over the past five years. A rather complicated levy on profits based on a field's rate of return is the primary tax on developments in Australia.

Gas reserves in this study include some of the early estimates of probable reserves for recent offshore discoveries. These fields have not been fully delineated, and reserves estimates are subject to a great degree of uncertainty. In general, this study has used the "50-percent" probability reserves number reported by the Western Australia Department of Mines. Total undeveloped nonassociated gas reserves in Australia are estimated to be 62.4 tcf in this report. This figure is much higher than total gas reserve estimates reported in the Oil and Gas Journal Worldwide Reserves Report, but in line with *Petroleum Economist* estimates.

The largest natural gas accumulations in Australia are listed in Table V–1. Those marked with an asterisk are undeveloped and included in this study.

Condensate yields are not extremely high in most Australian gas fields, but natural gas liquids are generally in the range of 3 to 6 percent of raw gas production. The only cost adjustment made to Australian capital costs is a 50-percent increase to production equipment and plant construction costs because of the remote locations of most of the undeveloped fields.

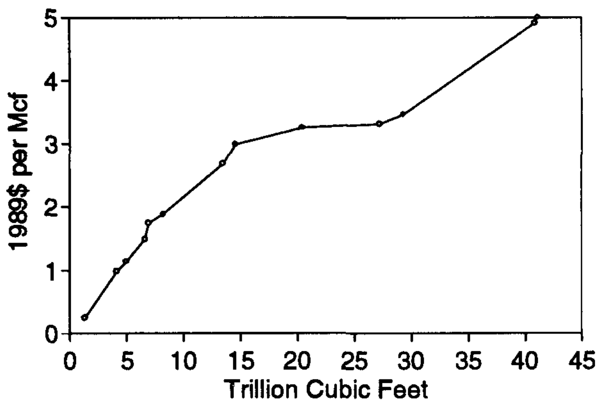
Table V–1 — Largest Natural Gas Accumulations in Australia

	EUR Gas (tcf)	Primary Product
Scott Reef	13.5	Gas*
Rankin North	8.2	Gas
Petrel	5.0	Gas*
Brecknock	4.9	Gas*
Gordon N	4.6	Gas*
Goodwyn	4.5	Gas/ Condensate*
Springton	3.5	Gas*
Tryal Rocks	2.8	Gas*
Scarborough	12.4	Gas*
Snapper	2.4	Gas/Oil

*Undeveloped

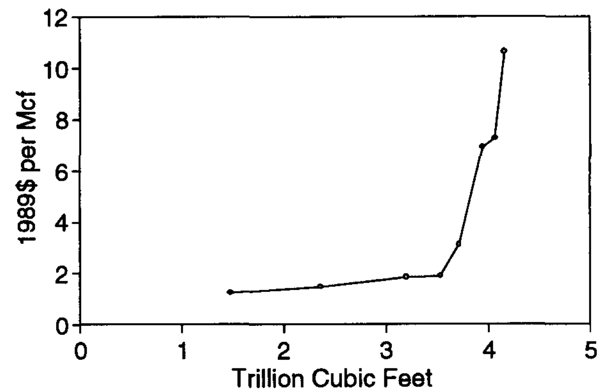
The largest undeveloped nonassociated gas field included in this study is the Scott Reef discovery, in water depths ranging from 165 to 1,000 feet about 250 miles offshore in the Timor Sea. For the purposes of this evaluation, the field was assumed to be developed in two stages: a group of shallow-water platforms over the submerged atoll (Scott Reef) and a group of tension-leg platforms in the surrounding deeper water. Development costs for this field have been estimated to be from $3.26 per Mcf to $6.67 per Mcf, depending on water depth. The Petrel and Tern fields, also in the Timor Sea in water about 300 feet deep, have estimated development costs of about $2.69 per Mcf. Scarborough field, offshore the Northwest Shelf, has probable revenues of as much as 12.4 tcf in water more than 3,000 feet deep. Although this figure is highly speculative, it is included in our inventory in order to be consistent with the inclusion of probable reserves in other Northwest Shelf fields. The largest onshore field included in our inventory, Springton, has estimated development costs of about $0.98 per Mcf. Total undeveloped nonassociated sales gas available from Australia is estimated to be about 53.5 tcf, most of which is relatively expensive offshore Northwest Shelf gas. The supply-cost curve for Australia is shown in Figure V–4.

Figure V–4 — Development Costs of Nonassociated Undeveloped Gas in Australia



Note: Year 2000 Oil Price Basis

Figure V–5 — Development Costs of Nonassociated Undeveloped Gas in Bangladesh



Note: Year 2000 Oil Price Basis

BANGLADESH

Oil and gas production in Bangladesh has progressed at a moderate pace since the earliest discoveries were made in the 1930's in the Sylhet area near the border with India. The government has adopted a policy of encouraging foreign operators since the early 1980's.

Production to date consists mostly of gas from nonassociated fields in the eastern portion of the country in folded horizons surrounding the Bay of Bengal and the Ganges River delta. Bangladesh has developed a large portion of its natural gas reserves, primarily from discoveries made in the 1950's and early 1960's. With few exceptions, condensate yields are extremely low in Bangladesh. The country has only one producing oil reservoir, a small accumulation in Sylhet field. Only one commercial gas discovery has been made to date offshore Bangladesh. This report relies mainly on information contained in the Petroconsultants data base. In general, Petroconsultants reserve estimates appear conservative.

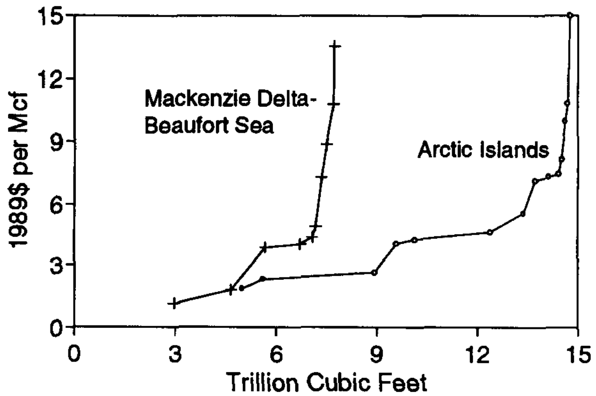
In order to bring gas to a port, it is assumed that all production is brought to Chittagong on the Bay of Bengal. Most fields, representing about 75 percent of the reserves identified in this report, are north of Chittagong and are assumed to share in the cost of a 210-mile trunkline along the eastern border of Bangladesh. Equipment costs and pipeline construction costs are assumed to require a 50-percent premium over U.S. costs because of infrastructure and terrain difficulties.

Although the estimates of development costs in this report vary widely for the various fields identified in Bangladesh, most reserves can be developed and brought to Chittagong for less than $2.00 per Mcf (Figure V–5). Total identified undeveloped nonassociated gas in Bangladesh is about 4.4 tcf, of which 4.1 tcf is estimated to be available for sales gas.

CANADA

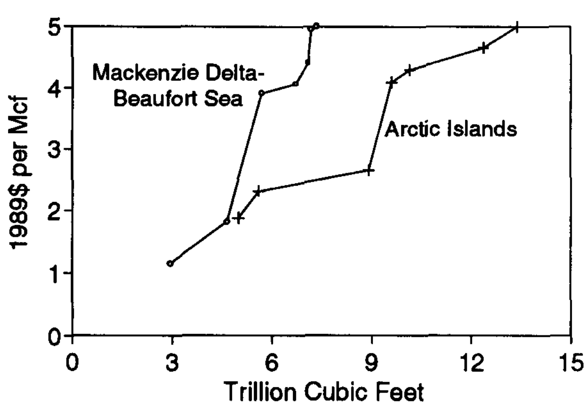
The nonassociated gas fields considered in the portion of this study devoted to Canada are the remote frontier discoveries made in the Mackenzie Delta, Beaufort Sea, and Arctic Islands areas. These regions are far removed from any existing infrastructure and will require a large investment to develop and deliver to markets. The Mackenzie Delta-Beaufort Sea fields may be hooked up to a pipeline for delivery into the Canadian transmission grid or for export to the United States as a gas, though the nearest existing pipeline is 1,400 miles away. The Mackenzie Delta-Beaufort Sea development cost reported here does not include a pipeline transmission toll and is essentially a field plant tailgate cost. The Arctic Islands cost includes only the cost of a pipeline to a liquefaction terminal on the nearest island (Figures V–6 and V–7).

Figure V–6 — Development Costs of Nonassociated Undeveloped Gas in Arctic Canada



Note: Year 2000 Oil Price Basis

Figure V–7 — Development Costs of Nonassociated Undeveloped Gas in Arctic Canada (Truncated at $5 per Mcf)



Note: Year 2000 Oil Price Basis

Several large gas accumulations have been discovered since 1963 in the Mackenzie River delta area, which is part of the Beaufort-Mackenzie Basin, which covers about 40,000 square miles on and offshore the Arctic Ocean coast of northwest Canada. The fields discovered are mainly trapped in Eocene sandstone reservoirs. In the Esso Canada application for Mackenzie Delta Export Approval (1988), nonassociated gas recoveries in the range of 80 to 90 percent were assigned to the discoveries in the region. Well productivities are very high, generally more than 20 MMcfd per well. Condensate yields vary from less than 10 to more than 40 barrels per MMcf. Gas plant liquids are also significant, averaging about 16.5 barrels per MMcf.

The Mackenzie Delta-Beaufort Sea field reserves estimates used in this study are taken from the estimates reported in the 1988 application for export by Esso, Shell, and Gulf. The National Energy Board (NEB) October 1989 Reasons for Decision that approved gas exports from the region reported NEB estimates that are very close to the applicant estimates but generally a little more conservative. Onshore development in the Mackenzie Delta area will probably be initiated with the Taglu (Esso) and Niglintgak (Shell) fields. Offshore development will probably be initiated with Amauligak (Gulf) oil production.

The reserves potential of the Mackenzie-Beaufort fields is fairly well defined, but production has been deferred because of a variety of technical and marketing difficulties. The Mackenzie Delta is more than 1,400 miles from the northern terminus of the Alaska Natural Gas Transportation System (ANGTS) Prebuild near Caroline, Alberta. Several alternative pipeline routes have been proposed to bring the gas south, but all proposals are contingent on a U.S. market for the gas. While most export policy questions have been settled through years of discussions between Canada and the United States and through a series of proposals submitted to the NEB and to FERC, the market value of gas over the past decade has not been high enough to justify the enormous investment that will be required to develop the fields and lay a pipeline to Caroline.

The Mackenzie Delta-Beaufort Sea fields will require drilling pads, artificial islands, and permafrost protection for development. Deeper water offshore in the Beaufort Sea will require protection from pack ice and ice floes with reinforced caisson construction or subsea completions. The Esso Canada export application listed drilling island costs in the range from $88 million (U.S. 1988$) to $333 million (U.S. 1988$) depending on water depth. Each field in the Beaufort Sea was assumed to require one island for development. A pipeline to Caroline will cross areas subject to severe winter weather as well as partial thawing and flooding in the spring. Numerous river crossings are also required. Cost estimates for the pipeline have been reduced significantly in the years since it was first proposed, but are still too high to compete in today's market. The Foothills Pipe Line, Ltd., application for the Mackenzie Valley Pipeline and ANGTS Prebuild Extension project submitted to the NEB in October 1989 estimated total capital cost for pipeline facilities, excluding financing costs, to be $4.4 billion Canadian (about $3.8 billion U.S. 1988$). Foothills estimated the capital cost of transportation to Caroline to be about $2.22 per MMBtu (Cdn 1988$). This pipeline toll has not been added to the field cost of gas in the supply curve following this section in order to allow comparison of Arctic Island and Mackenzie Delta gas on a similar basis. Addition of the pipeline toll to Mackenzie Delta gas will essentially be the cost of gas delivered to the U.S. border.

Pipeline fuel use is not considered in the evaluation of gas development costs in the other countries in this report; however, other fields studied have not required as lengthy a pipeline. In addition, a Mackenzie Delta pipeline will require chilling of the gas to protect permafrost. In applications to the NEB, pipeline fuel use is estimated to be about 3.8 percent of dry gas transported via the pipeline. For these reasons, an additional 2 percent is added to the lease and plant fuel consumption used in the economic analysis for both the Mackenzie Delta-Beaufort Sea and Arctic Islands areas (total of 4.5 percent).

Further north and to the east several large oil and gas discoveries have been made in the Sverdrup and Melville Basins underlying the Arctic Islands. These basins cover more than 173,000 square miles and contain up to 30,000 feet of sediments. Pan Arctic Oils, owned largely by the Canadian Government and representing a large consortium of private companies, has done much of the exploration in this area and has actually produced oil from the Bent Horn field for tanker shipment during the summer months. However, most of the discoveries have been primarily gas bearing. The Arctic Islands fields reserves estimates used in this study are taken from Pan Arctic Oils' 1986 Annual Report. The majority of the discoveries in this area are offshore in the deep channels between the islands and will require subsea completions with risers able to withstand the arctic pack ice. This region is about 600 miles south of the North Pole and is navigable by tanker only 2 or 3 weeks each year. The nearest existing airstrip is 200 miles to the southeast. A pipeline to the Mackenzie Delta area would be more than 900 miles long and would cross numerous channels 600 to 1,000 feet deep that are frozen most of the year, as well as numerous Arctic Islands.

A preliminary application to the NEB in 1981 for the Arctic Islands Pilot Project proposed LNG exports from Drake Point field. The application assumed a 100-mile pipeline to the south side of Melville Island would terminate at LNG liquefaction and loading facilities for transport to Montreal. The pipeline cost alone for this project was estimated to be $125 million (U.S. 1980$) plus $1.5 million per year pipeline operating costs. LNG liquefaction and loading facilities were estimated to cost about $750 million (U.S. 1980$), not including the cost of icebreaking LNG tankers.

Drilling and equipment costs are much higher in the Canadian Arctic than in most other regions studied because of the harsh environment, limited weather windows, remote locations, and lack of infrastructure. These costs were adjusted for the Mackenzie-Beaufort and Arctic Islands areas. An additional investment in artificial islands is also required for offshore wells in both areas. Discoveries to date in the Beaufort Sea have been in relatively shallow waters, and all development wells are assumed to be drilled from permanent artificial islands. Operating and maintenance expenses include an annual charge for maintenance of these islands in the Beaufort. Offshore wells in the Arctic Islands are assumed to be drilled from temporary ice islands and completed with subsea wellheads if water depths exceed ice scour depths. Shallow-water wells will require buried wellheads and flowlines to shore, or they may be drilled from onshore surface locations if very close to land. The cost of all offshore wells in the Arctic Islands was raised by $15 million over the cost of onshore wells to include the cost of subsea wellheads, flowlines, protective templates, and control umbilicals. Annual well operating expenses are similar to Norwegian Arctic costs, about $1.5 million per well. Production equipment, plant construction costs, and pipeline construction costs were raised 100 percent in both the Mackenzie-Beaufort and Arctic Islands areas.

The nonassociated gas reserves for each of the regions considered in this report are as follows: Mackenzie Delta (onshore) 6.9 tcf, Beaufort Sea (offshore) 2.0 tcf, Arctic Islands 15.9 tcf. The two largest nonassociated gas fields in this study are Drake Point (5.3 tcf) and Hecla (3.5 tcf) in the Arctic Islands, both of which lie partially on Melville Island, partially offshore. The largest nonassociated gas fields in the Mackenzie Delta onshore area are Taglu (3.2 tcf) and Parsons Lake (1.9 tcf). The largest offshore Beaufort Sea field is Issungnak (1.1tcf).

Sales gas after shrinkage and fuel use is estimated to be about 14.7 tcf from the Arctic Islands, and about 7.7 tcf from the Mackenzie-Beaufort area. Development costs for the largest Arctic Island field, Drake Point, is estimated to be about $1.88 per Mcf (U.S. 1989$). Again, this is only the cost delivered to a liquefaction terminal on Melville Island. Development costs in the other Arctic Islands fields range up to more than $10.00 per Mcf, delivered to the nearest potential tanker terminal location.

In the Mackenzie-Beaufort region, development cost of the Taglu field is estimated to be about $1.16 per Mcf (U.S. 1989$) and the Issungnak field is estimated to cost about $4.06 per Mcf. These costs are to a gas plant tailgate in the Mackenzie Delta.

CHILE

Chile is a net importer of oil but has developed its significant reserves of natural gas for use in the domestic petrochemical industry. The Cape Horn methanol plant near Punta Arenas began production of chemical grade methanol in 1988. Capacity is about 2,050 metric tons per day of methanol (about 60 MMcfd of natural gas feedstock), which is equivalent to about 6 percent of the world's methanol supply.

The vast majority of oil and gas in Chile is found in the sandstone Springhill formation of the Magellan Basin. This sedimentary basin is located in the Tierra del Fuego area and is now the source of more than three-quarters of Chile's total hydrocarbon production. Most of the large fields were initially produced for their crude oil and condensate reserves. Most produced gas has been reinjected in the past. With the completion of the Cape Horn plant, a market outlet for some of the gas has been created. The 10 largest gas accumulations in Chile are listed in Table V–2 (Petroconsultants data).

Data sources for this report do not indicate any significant undiscovered, undeveloped deposits of natural gas in Chile. In fact, the gas-bearing fields of Tierra del Fuego have been extensively developed for their liquids production. Large secondary gas caps now exist in these fields because of the gas reinjection programs. The investment required to produce these gas reserves is very small because nearly all the necessary wells have been drilled and producing and processing equipment is already in place. Recent discoveries in the waters of the Straits of Magellan and the creation of an outlet for gas production may spur more activity and exploration in the region.

An analysis in this report of Chile's discovered, undeveloped nonassociated gas reserves done in the same manner as the other countries yields an estimate of about 1.2 tcf of

Table V–2 — Largest Natural Gas Accumulations in Chile

	Original EUR gas (bcf)	Product	Primary Wells Drilled
Posesion	3,000	Gas/C/O	140
Daniel	1,500	Oil	147
Calafate	850	Gas/Cond	85
Cullen	800	Oil/Gas	177
Daniel Este	800	Oil	119
Chanarcillo	700	Gas/Cond	35
Tres Lagos	500	Oil	104
Canadon	350	Oil	67
Sombrero	165	Oil	30
Punta Delg E	105	Oil	24

reserves (1.1 tcf dry sales gas). A second analysis of the cost of marketing the reinjected gas has also been performed. The incremental investment required to produce this gas for export is based on the following assumptions:

- Twenty percent of wells require replacement.
- Twenty percent of wells require recompletion.
- New gas pipeline is laid to the nearest port.

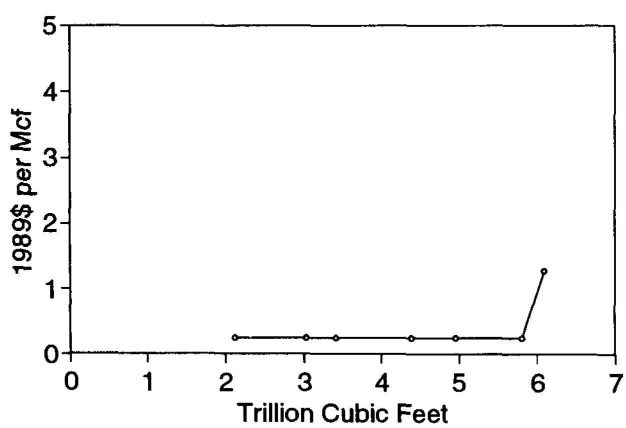
Total estimated available gas from the reinjection projects and the undeveloped portions of the known fields is about 6.45 tcf (6.1 tcf dry sales gas). This figure is based on the assumption that 75 percent of the initial gas reserves in these fields has been reinjected and can now be produced for export.

Production equipment and plant construction costs were raised 50 percent because of the distant location of these fields in Tierra del Fuego. Discoveries to date have been onshore or in nearshore waters.

The Daniel field (900 bcf) is the largest source of undeveloped nonassociated gas included in this study. Development costs are estimated to be about $0.25 per Mcf (Figure V–8). The undeveloped portions of nonassociated gas fields were estimated to cost no more than $1.28 per Mcf primarily because of the proximity of existing oil and gas infrastructure. Several other recent discoveries may hold significant amounts of nonassociated gas, but reserves estimates have not yet been published.

The sales gas development cost of the fields available for gas cap blowdown in the future is negligible after taking into account liquids revenue. A minimum cost of $0.25 per Mcf was assumed.

Figure V–8 — Development Costs of Nonassociated Undeveloped and Cycled Gas in Chile



Note: Year 2000 Oil Price Basis

CHINA

Hydrocarbon production in China from seeps and pits dates back many centuries, with natural gas produced from hand dug shafts and bamboo-cased wells in some areas. Large-scale commercial gas production did not commence until the 1950's. Gas use across the country has been rather uneven, depending on local supply and infrastructure. Technical limitations have apparently delayed development of some fields because of difficulties with low permeability or abnormally pressured reservoirs.

China's petroleum deposits are primarily distributed in the basins shown in Table V–3 (those with significant nonassociated gas production are noted with an asterisk).

The Songliao Basin in Manchuria contains China's largest oil field, Daqing. The Sichuan Basin in central China contains the largest concentration of gas-producing fields. Productive formations in Sichuan are mostly limestone deposits. Outside of Sichuan, China's other major source of gas production is associated gas from oil fields in the Songliao Basin. Recent gas discoveries have been made in the Bohai Sea and in the South China Sea near Hainan Island and onshore in the Shaan Gan-Ning and Tarim Basins. The onshore discoveries have indicated large gas potential in these areas, but they are in early stages of exploration. These basins contain both sandstone and carbonate sequences.

During the 1980's China entered into joint ventures and granted exploration concessions to several Western companies. Exploration to date, concentrated in the South China Sea and Bohai Sea, has not yielded oil and gas discoveries as large or numerous as hoped.

Table V-3 — Petroleum-Bearing Basins in China

Eastern Onshore Region	Central Region
Songliao (Manchuria)	Sichuan*
Bohai/Pohai/Huabei (near Beijing)	Shaan Gan-Ning/Eerduos/Ordos*
Subei (near Shanghai)	Zhaoshi/Ruoshui
Nanying/Xiang*	Jiuquan/Jiuxi
Jianghan*	Qaidam/Chaidamu/Tsaidam/Qinghai*
Dongpu/Zhongyuan*	Minhe
Maoming onshore	
Offshore Region	**North West Region**
Bohai Sea*	Tarim/Talimu/Xinjiang/Sinkiang*
North Yellow Sea*	Turpan/Tulufan
South Yellow Sea/Subei/Jiangsu	Junggar/Zhunger*
East China Sea/Donghai*	
Zhujiang (South China Sea)	
Yinggehai (Beibu Gulf)*	
Southeast Hainan (South China Sea)*	
Maoming/Sanshui (Pearl River mouth)	

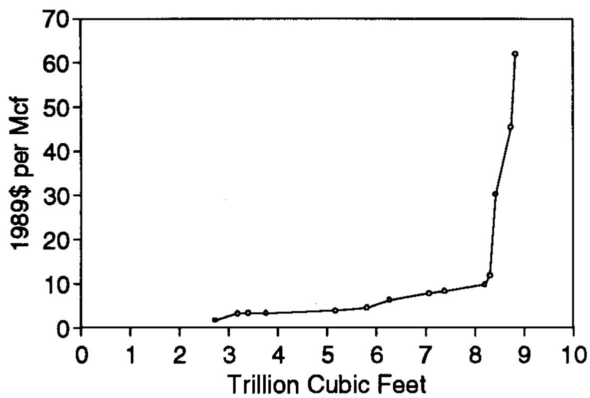
*Deposits with significant nonassociated gas production.

Natural gas has been a minor contributor to China's energy supply in the past, but the Energy Ministry has stated a desire to increase gas use and nonassociated gas supply. About 60 percent of China's gas production is available for consumption outside of oil and gas fields, but the only extensive natural gas delivery infrastructure exists in the Sichuan region. The most prospective areas for gas exploration are considered to be the onshore Sichuan, Shaan Gan-Ning, Tarim, Songliao, and Dongpu Basins and the offshore Liaodong (Bohai Sea) and Yinggehai-Southeast Hainan Basins.

Fields developed to date in China range in depth from 4,000 to more than 13,000 feet to the bottom of the deepest formation. Sichuan province, which produces nearly half of China's daily production of 1.4 bcfd, contains many reservoirs with high sulfur content in the gas. Because of the established demand in Sichuan, most fields in that area were considered to have an existing market for the purposes of this study. The 1987 Moxi discovery (897 bcf) is the one exception to this rule. Published reserves for individual fields are rare. The few data that China does release usually refer to a complex of fields in a producing region, rather than discrete fields. Extensions of existing fields and new fields are frequently found in these "complexes" and form an inventory of unexploited reserves. These fields are developed as needed to replace declining production in older fields in the same area.

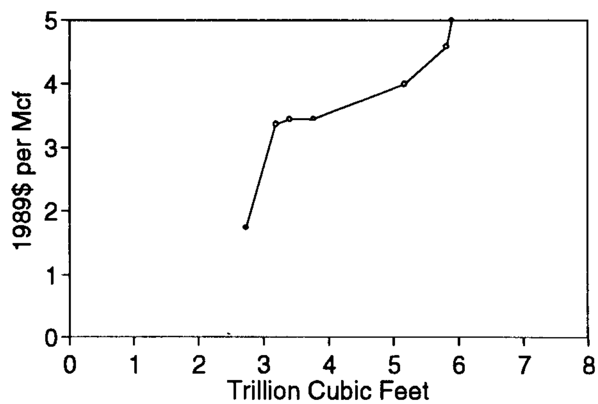
Because of the lack of a countrywide gas distribution system, many fields have probably not been fully developed even though they may have been placed on production many years ago. Some large discoveries in remote areas of western China have not been developed beyond the limited needs of nearby localities, if at all. The economic calculations assume these isolated fields share in the cost of a gas pipeline to Xianyang (Sian) on the Yellow River (Huang He). Fields in the Tarim Desert (that is, Sha and Donghe) would share the cost of a gas pipeline to Golmud (680 miles), where a junction with a Qaidam Basin line to Sian is made. Condensate is assumed to be transported to the refining center at Urumqi (350 miles). Fields in the Qaidam Basin are assumed to share in the cost of a gas pipeline to Sian (750 miles). Condensate is assumed to be transported to the refining center at Lenghu (120 miles). Newly developed fields in the Sichuan region are assumed to share the cost of a new gas pipeline to Guangzhou, near Hong Kong (630 miles). Locations of individual fields may be as much as 200 miles from any of the common trunklines. As these figures indicate, transportation is the most difficult part of any gas marketing project in China. The assumptions made in this report require

Figure V–9 — Development Costs of Nonassociated Undeveloped Gas in China



Note: Year 2000 Oil Price Basis

Figure V–10 — Development Costs of Nonassociated Undeveloped Gas in China (Truncated at $5 per Mcf)



Note: Year 2000 Oil Price Basis

extremely large pipeline investments. In some cases, pipeline costs are as much as 40 times the cost of drilling and completing wells.

Resource costs (of sales gas) calculated here range from about $1.74 per Mcf in the large offshore Yacheng field, to more than $40 per Mcf for gas in small discoveries in the Tarim desert. Most gas falls in the range from $3.50 to $8.00 per Mcf if it is to be brought to a port for export (Figures V–9 and V–10). Total identified undeveloped nonassociated gas in China is about 9.8 tcf, of which 8.8 tcf is estimated to be available for gas sales.

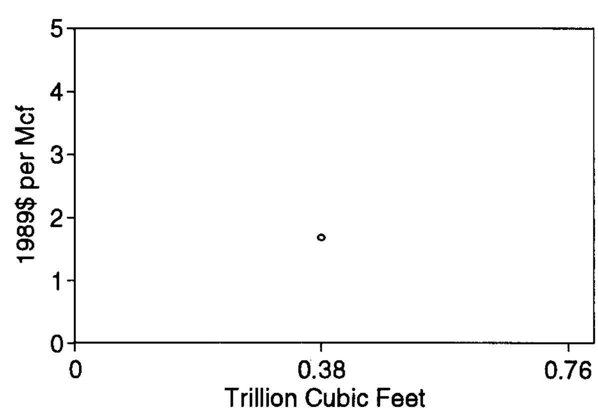
ECUADOR

Although Ecuador has produced oil for many years, very little gas, associated or nonassociated, has been produced. Early production came from fields along the coast, but virtually all production now comes from the Oriente region in the interior jungle east of the Andes. Much of the production is relatively heavy oil.

The only announced discovery of nonassociated gas in Ecuador is the Amistad field offshore, discovered in 1970, but still not developed. Proved reserves are 118 bcf, with estimates of total reserves ranging up to 400 bcf. Relatively little exploration appears to have taken place in offshore areas.

Amistad is in shallow water in the Gulf of Guayaquil. Test data indicate a very dry gas. Development costs are estimated to be about $1.67 per Mcf (Figure V–11).

Figure V–11 — Development Costs of Nonassociated Undeveloped Gas in Ecuador



Note: Year 2000 Oil Price Basis

EGYPT

Egypt's territory covers thick sedimentary strata deposited beneath most of the country. The area is characterized by complex geology and faulting associated with the Arabian Shield. Earliest petroleum production came from the coastal areas of the Gulf of Suez and has since moved offshore. Most producing reservoirs are sandstone traps. The offshore Gulf remains the most important Egyptian producing region. The western desert has also yielded numerous smaller oil discoveries in a series of folded structures. This area is the most open to foreign operators and has become more attractive recently after the completion of a gas pipeline to Alexandria. The Nile delta region has proven to be the most prolific gas-bearing region in the country, with numerous discoveries onshore and offshore.

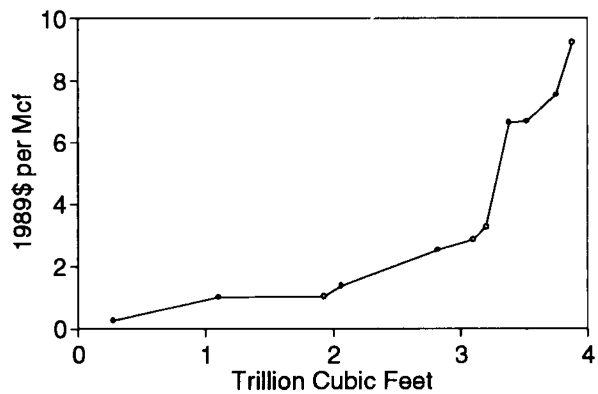
Egyptian oil production increased dramatically during the 1970's and has continued to grow at a slower pace during the 1980's. During the 1980's, gas production and consumption swiftly increased. Egypt consumes most of its gas production, and little gas is flared or reinjected. The government has encouraged gas production by addressing associated gas sales in production-sharing contracts with operators and has encouraged gas consumption to substitute for domestic electricity and oil use. Egypt's new concessions also cover production and sales of nonassociated gas by foreign companies and have encouraged development of gas-prone areas. Egypt has entered into take-or-pay gas contracts with producers that provide gas prices based on international fuel oil prices. However, the government has supplied gas to consumers at greatly subsidized prices that do not reflect the true costs of the gas.

The majority of large nonassociated gas fields in Egypt identified in this study are either developed or are included in plans for future incorporation into the country's gas grid. Fields with no production as of yearend 1990 were considered undeveloped and included in the inventory of gas available for export.

Cost assumptions utilized in resource cost calculations in this report include a 25-percent equipment premium. No other cost adjustments were made to Egyptian industry costs because of the established production history of the country and the relatively uniform terrain, with the exception of the Nile Delta marsh area.

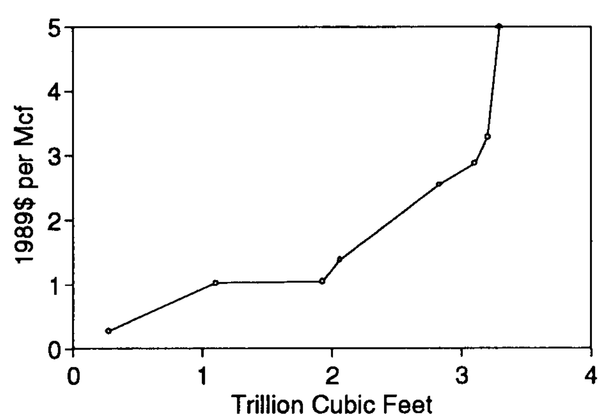
Resource costs of gas calculated here range from about $0.28 per Mcf for moderate sized discoveries with high condensate yields in the western desert, to about $9.00 per Mcf for small fields in the offshore Gulf of Suez (Figures V–12 and V–13). Most undeveloped fields are of small or moderate size. Production from fields in the western desert or offshore Mediterranean was assumed to be

Figure V–12 — Development Costs of Nonassociated Undeveloped Gas in Egypt



Note: Year 2000 Oil Price Basis

Figure V–13 — Development Costs of Nonassociated Undeveloped Gas in Egypt (Truncated at $5 per Mcf)



Note: Year 2000 Oil Price Basis

transported to El Hamra or Alexandria for export; Gulf of Suez fields were transported to either Port Said or Ras Gharib. Total identified nonassociated undeveloped gas in Egypt is about 4.2 tcf, of which 3.9 tcf is estimated to be available for gas sales.

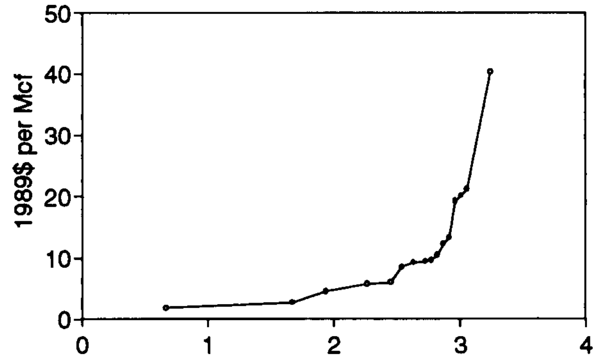
INDIA

Over the past decade, India has embarked on an intensive exploration and production program with the aim of reducing its dependency on imported energy. Future plans are as aggressive: the preliminary 1990–95 5-year plan includes $19.5 billion for exploration, compared to $7.1 billion spent in 1985–90. In 1989, India's petroleum industry surpassed Canada's as the second most active drilling rig operator. Despite these efforts, India still imports about 40 percent of its oil. Gas production increased dramatically during the 1980's. Production in 1988 increased 100 percent over 1984. Gas production in 1990 was about 1.0 bcf per day.

India is making an effort to replace imported petroleum with domestically produced natural gas, and gas consumption increased sixfold from 1980 to 1988. However, flaring still consumes over 30 percent of gross production. The Gas Authority of India recently completed a 1,094-mile, 36-inch gasline from Hazira (near the Bombay High offshore area) to Kanpur-Jagdishpur to encourage greater use of gas in both industrial and residential-commercial markets. Plans have been announced for construction of a 935-mile gas pipeline from the Bombay High area across the southern portion of the country to Madras.

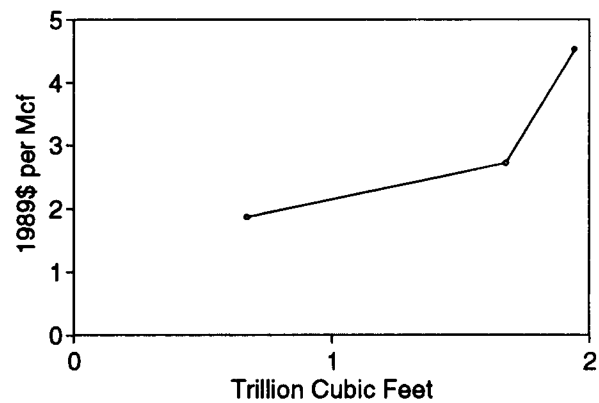
The Indian subcontinent is primarily a crystalline shield, but several sedimentary basins lie along the circumference. Oil and gas production is centered in three main basins, all of which have onshore and offshore deposits: the Bombay-Cambay Basin, which is mostly offshore in the Gulf of Cambay and which produces almost two-thirds of India's oil; the Krishna-Godavari Basin in Andra-Pradesh state on the east coast; and the Cauvery Basin in Tamil Nadu state. Other basins include the Assam Basin in the northeast provinces and the Jaisalmer Basin in the northwest near the Pakistani border. Few individual fields have very large reserves. Most gas discoveries are of moderate-to-small size (less than 100 bcf) with moderate productivity.

Figure V–14 — Development Costs of Nonassociated Undeveloped Gas in India



Note: Year 2000 Oil Price Basis

Figure V–15 — Development Costs of Nonassociated Undeveloped Gas in India (Truncated at $5 per Mcf)



Note: Year 2000 Oil Price Basis

Because most Indian fields are near the coast, no common trunklines were assumed necessary for development for export. A 50-percent premium for equipment and pipeline construction was assumed because of infrastructure difficulties. No other construction premiums were added to Indian costs. Export points were assumed to be located at the nearest existing port to each group of fields in this study. In the

Bombay-Cambay area, production was assumed to be transported to either Bombay, Bharuch, or Daman. Kakinda and Negapatam were assumed to be the gathering points for production in the Krishna-Godavari and Cauvery basins, respectively. Fields in the northeastern state of Tripura were assumed to be able to export through the Bangladesh port of Chittagong, the most direct route to the sea.

Primarily because of the relatively small field size and large investment in pipelines assumed here, development and transportation costs for the identified Indian fields are rather high. Most reserves cost more than $2.70 per Mcf (Figures V–14 and V–15). Total identified undeveloped nonassociated gas in India is about 3.8 tcf, of which 3.2 tcf is estimated to be available for sales gas.

INDONESIA

Oil production in Indonesia started in the 19th century from numerous onshore fields on Sumatra and on Java near Jakarta. Subsequent exploration and development established Indonesia as one of the world's largest oil producers before World War II. Large volumes of associated gas and nonassociated gas discoveries in the 1970's have allowed Indonesia to become the world's largest exporter of LNG, mainly to Japan. State-owned Pertamina has awarded numerous production-sharing contracts with foreign operators in an effort to stem forecasted oil production declines.

The majority of hydrocarbon deposits occur in groups of relatively small, discontinuous, and stacked reservoirs. While much of the oil produced is light, significant quantities of onshore oil must share heated pipelines because of the low pour point of the crude. Many gas fields have significant reserves, but development has been delayed because of low flowrates and remoteness from populated areas of consumption. Offshore reserves also are distributed across numerous reservoirs, but accumulations generally are somewhat larger than onshore. Offshore field development is similar in style to the Gulf of Mexico off the U.S. coast.

The Indonesia island system encompasses two very large arcs of islands (an inner, volcanic origin arc and an outer, tertiary island arc) surrounding several relatively shallow seas. The major sedimentary basins are listed in Table V–4.

Because of declining oil reserves during the 1980's, Indonesia is attempting to diversify its exports and encourage domestic consumption of gas rather than oil. Gas reserves tripled during the 1980's. Indonesia currently exports more than 725 bcf of LNG to Japan each year, which accounts for about 50 percent of the country's total gas production. Indonesia expects earnings from LNG exports to exceed those from crude by the mid- to late 1990's. Arun, one of the largest gas fields in southeast Asia and capable of very high flowrates, currently is being produced at over 2 bcfd. At that rate, the field will be depleted sometime between 2010 and 2020. Two large LNG plants process most of Indonesia's exports: the Bontang plant in East Kalimantan, which liquefies gas from the coastal-offshore Badak field, and the Lho Seumawe plant in North Sumatra, which liquefies gas from the Arun field. At yearend 1990, the Lho Seumawe plant was capable of processing 2 bcf per day, producing 39,000 tons of LNG per day from six LNG trains. Plans to construct a sixth train at Bontang are also under way. Pertamina is exploring the feasibility of placing an LNG plant on Natuna Island to tap the large reserves in that area. A methanol plant is located on Bunyu Island in northeast Kalimantan, and Pertamina is also planning

Table V–4 — Major Sedimentary Basins in Indonesia

	Area (sq km)	Thickness (ft)
North Sumatra	25,000	25,000
Central Sumatra	50,000	9,000
South Sumatra	75,000	15,000
East Java	18,000	18,000
Southeast Kalimantan	100,000	10,000
Northeast Kalimantan	20,000	10,000
West Irian	20,000	8,000
West and East Natuna	38,000	13,000

construction of LPG plants near the Arun and Bontang plants.

Most nonassociated gas fields included in this study are found at depths shallower than 12,000 feet. Initial well deliverabilities range from 4 to 20 MMcfd. Nonhydrocarbon gases generally are low except for some large concentrations of CO_2 in North Sumatra and the South China Sea. Condensate yield varies from less than 5 barrels per MMcf to more than 40 barrels per MMcf. The Arun field was considered fully developed and has not been included in this report. The largest undeveloped nonassociated gas field identified in this study is the offshore "AL" discovery in the Natuna Island area. That field is reported to contain about 70 tcf of gas but is mostly CO_2. Because of the remote location and low hydrocarbon content, development costs for the field were calculated to be more than $16.00 per Mcf. The largest hydrocarbon gas field included is Tunu, located in shallow waters in marshland off the coast of Kalimantan. That field is producing oil and some gas, but the nonassociated gas reserves are mostly undeveloped. About 6.0 tcf of undeveloped nonassociated gas was estimated to be contained in Tunu, with a development cost of $0.34 per Mcf. Total undeveloped nonassociated gas reserves in Indonesia have been estimated in this study at 60.4 tcf (including only the hydrocarbon portion of the AL/Natuna field).

Estimates of the cost of developing any field are highly dependent on transportation (that is, pipeline costs) for each field or group of fields. Currently, the largest infrastructure for oil and gas development exists in Java, near Jakarta; in Northern Sumatra, near the Arun field; and in East Kalimantan, near the Bontang LNG plant and the Bunyu Tapa methanol plant. The extent of infrastructure development in other areas, particularly the large deposits found offshore in the South China Sea near Natuna, is highly variable. The 110 fields included in this study were grouped into about 40 developments to share pipeline costs. Pipelines were assumed to be laid to the nearest port. Location cost adjustments were made for production equipment, gas plant construction, and offshore platforms. Equipment and construction costs were increased 50 percent; platform costs were decreased 20 percent.

Total nonassociated sales gas available from Indonesia is estimated to be about 54.9 tcf. Costs of development vary widely, but generally are below $3.00 per Mcf (Figures V–16 and V–17).

Figure V–16 — Development Costs of Nonassociated Undeveloped Gas in Indonesia

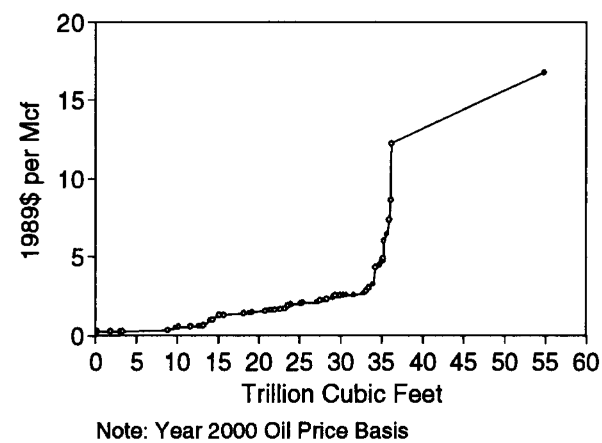
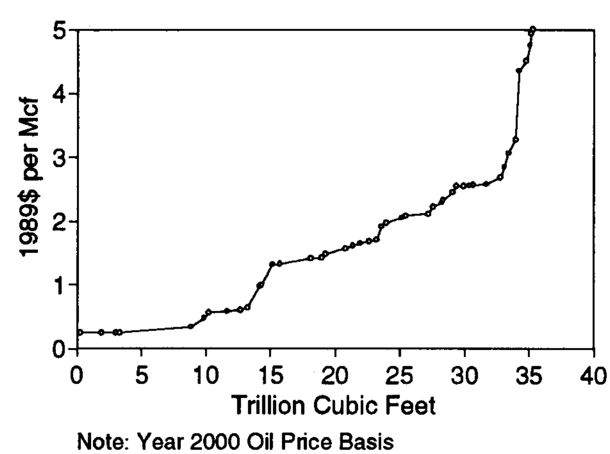


Figure V–17 — Development Costs of Nonassociated Undeveloped Gas in Indonesia (Truncated at $5 per Mcf)



IRAN

Iran has been host to one of the oldest petroleum industries in the Middle East. The first commercial oil field in Iran was discovered in 1908 (Masjid-i-Sulaiman). Most Iranian fields contain oil deposits in the Asmari limestone or its equivalent, an Oligocene-Lower Miocene limestone that has fairly low porosity but high secondary permeability. The majority of Iran's major fields are located in Khuzestan Province in the southwest portion of the country. Most deposits are anticlines paralleling the folds of the Zagros Mountains. To the west, more sandstone formations are intermixed with the Asmari. Many of the more recent oil and gas discoveries (post-1970) are located in the Persian Gulf. These fields produce from one of two trends: a shallow trend similar to the onshore Iranian fields, or a deeper trend related to the formations of the Arabian Peninsula.

Below the Asmari, large gas accumulations have been found in Lower Cretaceous, Jurassic, and Permian Khuff formations. Kangan, just off the Bushire Coast, has estimated reserves of 100 tcf in the Khuff. Most of the oil fields in Iran have very large primary gas caps that have been supplemented by secondary gas accumulation after oil production commenced. In addition, at least one instance of significant gas channeling to the Asmari from a deeper gas reservoir has been reported. Poor cement in the 1964 gas discovery well at Masjid-i-Sulaiman channeled an estimated 350 MMcfd from the gas horizon to the Asmari. Individual well productivity is very high in most Iranian fields, similar to that seen in the Khuff formation of Saudi Arabia. The *Oil and Gas Journal* reported total gas reserves for Iran as of January 1, 1991, to be more than 600 tcf. A large portion of these reserves were not included in this study because of their associated gas nature.

Iran exported gas to the Soviet Union prior to the Islamic Revolution and has also developed a high rate of domestic utilization. Gas sales to the U.S.S.R. were resumed in 1990 at peak rates of more than 285 MMcfd. Iran currently has two main trunklines to carry gas from the southwestern producing regions: IGAT–1, which connects with Soviet transmission lines for sales to the U.S.S.R. and backhaul arrangements for sale to Europe, and IGAT–2, which currently extends only as far as Isfahan but also has proposed links to the Soviet Union. Recent proposals to ship gas to Europe via a pipeline across Turkey have also been announced. Produced gas from nonassociated gas fields is also used for injection into oil reservoirs.

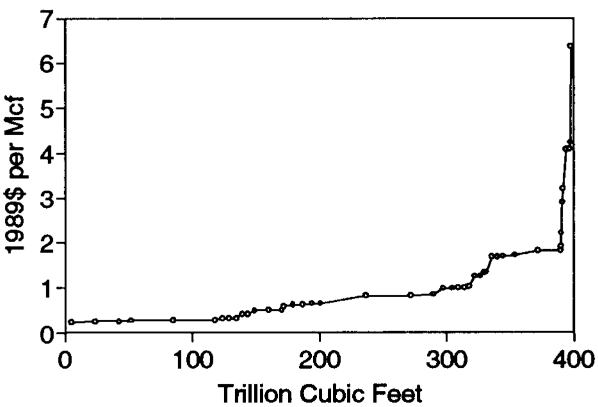
The Iran-Iraq war severely disrupted Iran's petroleum industry, and exploratory drilling reportedly was limited to deeper tests in established fields. Very little exploration and production data dating from after the Islamic Revolution are available from Iran. The analysis here assumes little new development has occurred since that time. Now that the Iran-Iraq war is over and the demand for Iranian crude has increased, Iran's recovery is well under way. In 1989, Iran announced a huge gas discovery at Lamard, with reserve estimates of 282 tcf. For purposes of this analysis, a risked volume of 71 tcf was used for economic evaluation. New development of both oil and gas fields may rapidly accelerate.

Iran's offshore potential has already been proven to be extremely large. Pars, a gas discovery just off the coast near Kangan, has estimated reserves of 100 tcf. As much as 30 percent of the North Field structure off Qatar also extends into Iranian waters.

Much of Iran's oil and gas production contains significant amounts of H_2S, and costs have been modified to reflect this fact where appropriate. Although Iran has a well established petroleum industry, it is distant from most equipment manufacturers. Equipment and pipeline costs have been increased by 50 percent over U.S. standards because of infrastructure problems.

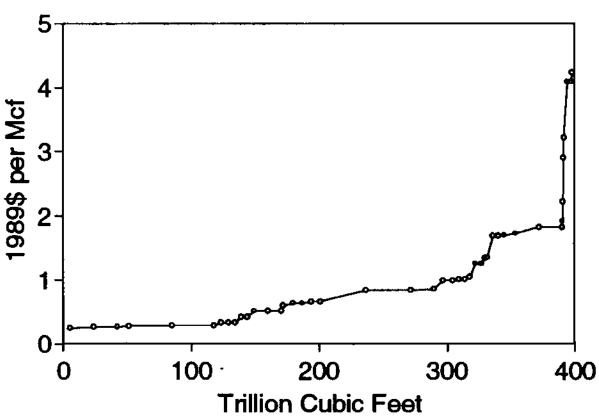
Iran contains the largest accumulations of inexpensive natural gas of any country in this study. Numerous fields capable of high flowrates are located in the south and west of the country near the Persian Gulf. Approximately 439 tcf of undeveloped nonassociated gas was identified in this study, about 397 tcf of which is sales gas. Nearly all the gas is estimated to cost less than $3.00 per Mcf to develop and transport to the coast, and about

Figure V–18 — Development Costs of Nonassociated Undeveloped Gas in Iran



Note: Year 2000 Oil Price Basis

Figure V–19 — Development Costs of Nonassociated Undeveloped Gas in Iran (Truncated at $5 per Mcf)



Note: Year 2000 Oil Price Basis

297 tcf is estimated to cost less than $1.00 per Mcf (Figures V–18 and V–19).

IRAQ

The oldest and largest oil field in Iraq, Kirkuk, was discovered in 1925 near the "Eternal Fires" gas seepages north of Baghdad that have been known since ancient times. The Rumaila field, discovered in 1953, in southern Iraq potentially contains even larger reserves within Iraqi territory and extends into Kuwait. Prior to its invasion of Kuwait, Iraq was exporting 300 MMcfd of Rumaila associated gas production to Kuwait. Iraq covers a portion of the Arabian-Iranian basin and contains hydrocarbon reservoirs similar to those in Saudi Arabia. Most fields in the north are large carbonate anticline traps with prolific well rates and significant sulphur content. Fields in southern Iraq have similar producing characteristics but are mostly sandstones. The majority of gas reserves exploited to date are associated gas.

Iraq nationalized most of its production in the early 1970's. Iraq National Oil Company became the sole operator in Iraq in 1980 after the remainder of foreign interests were nationalized. Little exploration or production data have been available from Iraq since nationalization. Iraq has claimed that it has pursued an aggressive exploration program that has yielded many new discoveries and identified numerous undrilled structures. In 1988 Iraq increased its published estimates of the country's gas reserves by 170 percent, after increasing its estimate of crude oil reserves by 39 percent the previous year.

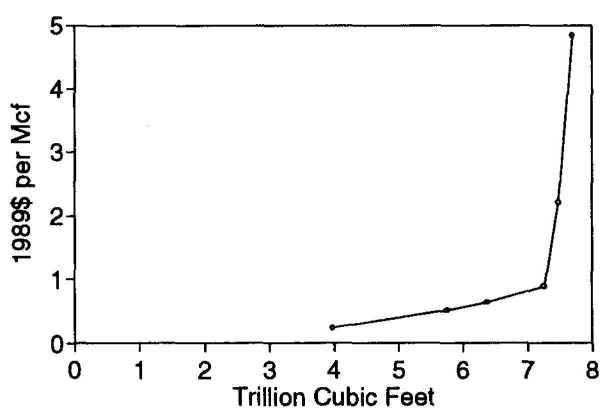
Until the late 1980's, Iraq flared most of its gas production. Flaring has been reduced but still amounted to 42 percent of gas production in 1988. No large accumulations of nonassociated gas have been reported in the sources to which this study had access. Several fields appear to have reservoirs that are predominately gas with light oil or that have oil reservoirs with large gas caps. Mention of gas reserves in any description of these fields is usually only in passing. Bai Hassan, one of the very large associated gas deposits in Iraq, has been included in this report's gas resource inventory in much the same manner as undeveloped nonassociated gas reserves. The associated gas that may be available for development independent of the field's oil reserves has been assumed to require new wells in the gas cap, new gas handling facilities, and a new gas pipeline for marketing. Total gas reserves from this field amount to 7.5 tcf, of which 2.0 tcf has been included in this report as excess gas available for immediate sale. Other oil fields in Iraq may also have very large gas caps that are available for production; Bai Hassan should be a representative example.

The largest nonassociated gas accumulation identified is Anfal field, which is located near Kirkuk. Condensate and natural gas liquids production appear to be very high in Iraqi gas reservoirs; thus, the cost of development allocated to sales gas can be very low. Distance from a trunkline to the field and the resultant pipeline costs are the main factors influencing the estimated resource cost. In most cases, the cost of new pipelines makes up nearly 90 percent of estimated development cost.

All of the fields identified here are in northern Iraq. Pipeline investments are assumed to require lines from each field to the Baghdad area and common gas and condensate trunklines from there to the port of Basra, about 250 miles to the southeast. Costs of the common trunkline have been allocated among the six fields in this study.

The four nonassociated gas fields and one gas cap included in this study have estimated sales gas resource costs ranging from less than zero to nearly $5 per Mcf (Figure V–20). The large accumulations have very low development costs because of liquids that provide more than $2 per Mcf of revenue. The economics of smaller fields with high estimated development costs are hampered by pipeline investments.

Figure V–20 — Development Costs of Nonassociated Undeveloped Gas in Iraq



Note: Year 2000 Oil Price Basis

Total available gas identified in this report amounts to about 8.7 tcf, of which about 7.1 tcf is sales gas.

KUWAIT

Kuwait, one of the world's largest oil exporters, has also expanded into large-scale downstream operations outside of the country. The national oil company, Kuwait Oil Company (KOC), conducts all field operations in Kuwait. KOC assets were fully nationalized in 1975.

Production mainly comes from large domal sandstone structures including Burgan Field, which is probably the world's second largest oil field, after Ghawar in Saudi Arabia. Burgan is part of a structure that includes the Magwa and Ahmadi Fields. Total reserves estimates for these fields range from 66 billion to 85 billion barrels. Cumulative oil production of over 19 billion barrels from Burgan makes it the world's most prolific oil field. All production is from onshore fields. Relatively little offshore exploration has taken place because of boundary disputes with Iraq and Iran.

Gas production has historically been all associated gas, the majority of which is marketed. Some nonassociated Khuff gas exploration has taken place in recent years according to some reports, but virtually no data are released by the government other than total country aggregate reserve and production volumes. Some reports also hint at the existence of nonassociated gas reservoirs in oil fields. Because of Kuwait's gas requirements, it is likely that any significant source of natural gas in these areas has been developed.

Eighty-nine percent of produced gas in Kuwait is consumed, and only a little more than one percent is reinjected. Kuwait imported large volumes of gas from Iraq prior to the invasion to supply its refining and petrochemical industry. Plans for further expansion of the petrochemical industry were being explored that would have required increased gas imports or increased production from recently developed light oil fields capable of providing associated gas. Total associated gas reserves in Kuwait are reported to be 48 tcf.

LIBYA

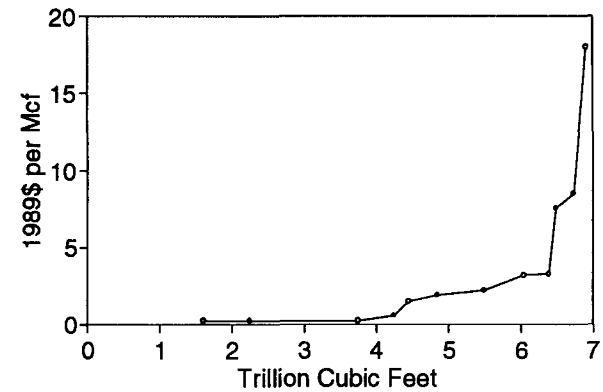
Although primarily an oil producer, Libya has significant nonassociated gas deposits that have not been exploited. Natural gas fields have been discovered in four main regions: the southwest near the border with Algeria; the Hamada Al Hamrah Plateau south of Tripoli; offshore Tripoli; and to the east, the major oil-producing region of the Sirte Basin, which also extends offshore into the Gulf of Sidra.

Little descriptive information about Libya's fields is available. Gas well productivity in Libyan fields appears to be moderately high, with high condensate yields. Reserves data are scarce, and Petroconsultants estimates have been used for most fields. The estimates are probably very conservative. Libya also produces large volumes of associated gas from its oil fields. Over half of all gas production is either flared or reinjected. In 1988, flaring amounted to more than 20 percent of gross gas production. Libya is evaluating projects to increase domestic gas use, as well as expand imports of gas as LNG or as gas via a pipeline to Italy.

Political problems have hindered foreign companies' participation in Libya during the past few years, but the Libyan government is making an effort to encourage the return of foreign involvement in exploration and production. Production volumes have fallen well below their peak in the early 1980's, and excess pipeline capacity currently exists. Fields near the Algerian border were assumed to send production to pipelines in Algeria. Fields in the Sirte basin were assumed to send production to existing pipelines, while offshore fields and fields in the Hamada Al Hamrah were assumed to require new pipeline construction. The petroleum industry in Libya is well established, and the only adjustment made to investment costs in this analysis is a 50-percent equipment installation premium.

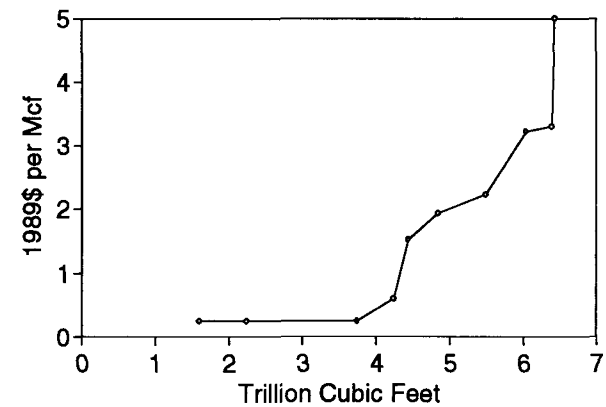
A total of 6.9 tcf of undeveloped nonassociated gas was identified in this study, 5.9 tcf of which is sales gas. Individual field reserves are reported to be fairly small, yielding rather high development costs (Figures V–21 and V–22). However, the high condensate and NGL production allows for moderate gas production costs. About 4.1 tcf of Libya's

Figure V–21 — Development Costs of Nonassociated Undeveloped Gas in Libya



Note: Year 2000 Oil Price Basis

Figure V–22 — Development Costs of Nonassociated Undeveloped Gas in Libya (Truncated at $5 per Mcf)



Note: Year 2000 Oil Price Basis

nonassociated gas is estimated to cost less than $2.00 per Mcf.

MALAYSIA

Virtually all Malaysian production is from offshore fields discovered during the last 20 years. Production is split between the continental shelves of the two main regions of the country: the Malay Basin offshore Trengganu state of peninsular Malaysia and the Sarawak and Sabah states in the northwest of Borneo island. Water depths range from 110 to 350 feet.

Most oil fields have large gas caps and produce at high GOR's. Production from offshore Sarawak fields is transported to shore via a common two-phase flow pipeline to the LNG plant at Bintulu. Malaysia is a major supplier of LNG to Japan, exporting about 300 bcf per year from Bintulu. Production from offshore Trengganu is brought ashore at Kerteh, then sent via pipeline to consuming areas for domestic consumption. The national oil company, Petronas, currently is not yet allowing significant gas export. Multinational oil companies operating under production sharing contracts with Petronas normally produce only the oil rim of reservoirs. Strict regulations limit the amount of associated gas production. A large percentage of associated gas production is reinjected for pressure maintenance. A major expansion of the domestic gas distribution network is planned to bring gas to Kuala Lumpur, the west coast of peninsular Malaysia, and to Singapore. Pipeline cost calculations in this project assume a new offshore pipeline from each group of fields developed is constructed to a common trunkline starting about 20 miles from shore. Location cost adjustments were made for production equipment, gas plant construction, and offshore platforms. Equipment and construction costs were increased 50 percent; platform costs were decreased 20 percent.

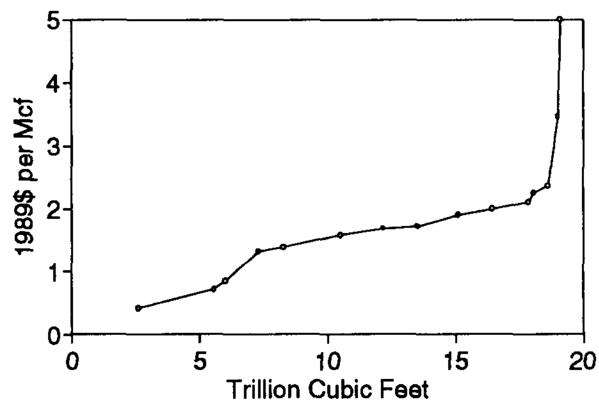
Most nonassociated gas reservoirs in Malaysia are rich in condensate and natural gas liquids (NGL's) (on the order of 6 to 8 percent NGL). Reservoirs are very similar to U.S. Gulf Coast reservoirs. That is, numerous reservoirs are stacked on top of each other in Miocene sandstones. Initial well capacities are 9 to 20 MMcfd, and reservoir depths generally are less than 9,000 feet. Nonhydrocarbon gas content generally is low.

Development of two large discoveries—Pilong, expected to be mainly nonassociated gas, and Mid-Ridge, expected to be mainly oil-bearing—has been delayed because they lie in a disputed area of the Gulf of Thailand. Total gas in the two fields is expected to be up to 9.5 tcf of the original gas in place (OGIP). Thailand and Malaysia are negotiating a split of production from those fields. Pilong field has been included in this study (Malaysia's estimated share). The largest undeveloped nonassociated gas field included in this report is the Jemeh field offshore Trengganu, in 250 feet of water. Jemeh is typical of most fields in Malaysia, with numerous stacked reservoirs, but appears to contain more nonassociated gas than most. The field was discovered in 1969, but development has been delayed because of the lack of a market for the gas. As of this writing, Petronas and Esso, the operator, were close to an agreement that would allow development of Jemeh to proceed. Startup date is tentatively scheduled for April 1992. Estimated reserves are 3.0 tcf, with development costs of $0.43 per Mcf.

Other large fields included in this report are the F6, F13, F14, and M3 fields. Nonassociated gas reserves in these fields averages about 1.2 tcf. Some of these fields are partially developed or have large amounts of both associated and nonassociated gas. Total estimated undeveloped nonassociated gas reserves in Malaysia identified in this report amount to about 21.5 tcf.

Total nonassociated sales gas available from Malaysia is estimated to be about 19.1 tcf. Costs of development vary widely, but generally are less than $2.00 per Mcf (Figure V–23).

Figure V–23 — Development Costs of Nonassociated Undeveloped Gas in Malaysia



Note: Year 2000 Oil Price Basis

MEXICO

Mexico contains several important sedimentary basins, most of which are primarily oil-bearing carbonates:

- *Tabasco-Campeche*—onshore Reforma Basin, offshore Bay of Campeche.
- *Tampico-Tuxpan*—central Gulf of Mexico coastal plain, "Golden Lane" limestones.
- *Isthmus of Tehuantepec*—highly faulted Tertiary sandstones.
- *Veracruz*—thick Tertiary sediment, some gas production.
- *Burgos*—part of Rio Grande embayment, mostly gas-bearing sandstones.
- *Sabinas*—Lower Cretaceous dolomite and Jurassic sandstone, mainly gas reservoirs in Nuevo Leon and Coahuila states.

Mexico has a long history of oil and gas production, dating back to the 19th century. Mexico nationalized oil and gas exploration and production in 1938, and all operations since then have been conducted by Pemex. Pemex has been successful in its exploration and development efforts, particularly in oil, the main focus of its efforts. Oil and gas provide more than 80 percent of Mexico's energy needs. Pemex has had problems financing its exploration expenses and has made tentative contact with private industry for joint ventures. Exports of oil and gas to the United States have always been highly dependent on political considerations, and gas exports have not been pursued by Pemex because of local demands.

Early oil production in Mexico came from the highly permeable limestone reef structures of the "Golden Lane" along the Gulf Coast south of Tampico. More recent oil and gas development has occurred in discoveries in the Reforma Basin onshore and the Campeche Platform in the Bay of Campeche. Fluid qualities vary widely, but generally reservoirs contain medium-density oil and 3 to 4 percent sulfur. Onshore gas accumulations are generally located in numerous small fields that deplete in less than 15 years in the Burgos and Sabinas Basins. Recent offshore discoveries have been mainly concentrated in the Bay of Campeche, with a few fields found offshore Veracruz and Baja California.

Pemex has not released much information on discoveries or production from individual fields, and, as a result, the data base for Mexico is extremely sketchy in this report. Reserves estimates are probably very conservative.

Most of Mexico's large accumulations of gas reserves are contained in the solution gas of the offshore oil fields. These fields appear to contain virtually all oil-bearing reservoirs with limited gas caps. Onshore fields in the Tabasco and Veracruz states bordering the Bay of Campeche contain larger gas caps and some nonassociated gas reservoirs. The only other region with significant accumulations of nonassociated gas is the Rio Grande embayment, which is a continuation of the onshore south Texas sandstone basins. Most major discoveries in these areas were made in the 1940's and 1950's.

The large oil and gas resource held in the Chincontepec trend has been mostly uneconomic to date because of low well productivity. The mostly sandstone reservoirs cover an area of 4,300 square miles in the states of Vera Cruz, Puebla, and Hidalgo. Potential oil-in-place is estimated to be about 110 billion barrels, along with gas-in-place of 40 tcf. However, poor porosity and permeability development limits estimated recovery to less than 10 percent of the hydrocarbons in place. Less than 250 wells are producing, most of which required fracturing. This area may benefit from horizontal completion technology in the future. No Chincontepec gas reserves are included in this report because of their apparent association with oil.

The table below highlights the largest natural gas reserves in Mexico as reported by Petroconsultants. As the list indicates, the vast majority of gas reserves are associated gas. Some reinjection has taken place for pressure maintenance or conservation purposes, but the majority of the produced gas has been flared or consumed.

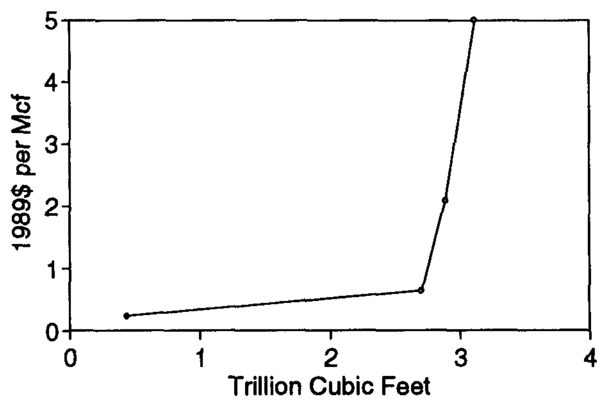
The 10 largest gas accumulations in Mexico are listed in Table V–5 (Petroconsultants data).

The largest undeveloped nonassociated gas identified in this report is the deep extension of

Table V–5 — Largest Natural Gas Accumulations in Mexico

	EUR (bcf)	Primary Product	Wells Drilled
Akal-Nohoch	8,000	Gas/Oil	64
Jose-Colomo	2,837	Gas	200
Reynosa	2,620	Gas	171
Poza Rica	2,400	Oil	249
Samaria (Berm)	2,000	Oil	83
Abkatun	2,000	Oil	35
Hormiguero	1,500	Gas	70
Cardenas	1,000	Oil	34
Cunduacan (Bm)	770	Oil	42
Arenque	750	Oil	40

Figure V–24 — Development Costs of Nonassociated Undeveloped Gas in Mexico



Note: Year 2000 Oil Price Basis

the Reynosa field slated for development during 1989 and 1990. The reserves and deliverability estimates used here are representative of the characteristics of fields in the area. It is not known how much of the gas is committed. Numerous other smaller nonassociated gas discoveries are made each year in Mexico, but they are generally small, with individual well productivity less than 4 MMcfd. The reserve size cutoff of 100 bcf per field used in this report excludes these small discoveries. These fields are generally in established producing areas and development costs will be similar to the Reynosa Profundo estimate.

Development costs in Mexico are very similar to costs in the United States. A 15-percent increase to production equipment and plant construction costs was made in this study because of potential local infrastructure or transportation difficulties. Because of the high degree of gas utilization in Mexico, few undeveloped nonassociated gas fields were identified. The largest field included in this report, Reynosa-Profundo, is a deep extension of the existing Reynosa field. Development costs for Reynosa-Profundo are estimated to be about $0.65 per Mcf (Figure V–24). A total of 3.5 tcf of nonassociated undeveloped gas is identified in this study.

NEW ZEALAND

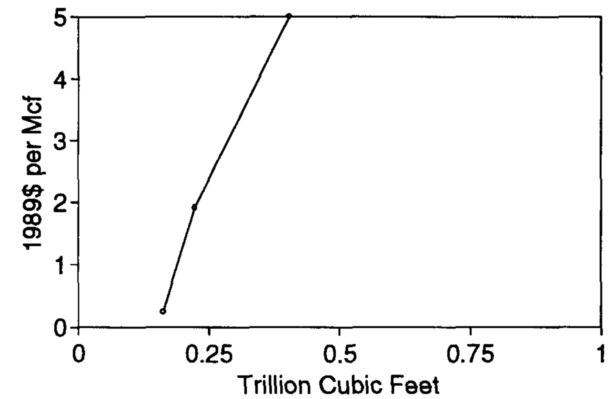
Gas and condensate production from several fields in the Taranaki Basin initiated commercial hydrocarbon production in New Zealand. Subsequent exploration has yielded small discoveries in other areas, but the primary petroleum region of New Zealand remains the Taranaki Basin, both onshore and offshore in the area between the North and South Islands.

Condensate yields have generally been very high in fields discovered to date. A gas cycling project was initiated at Kapuni field (discovered in 1959) in 1980, when condensate yield was more than 60 barrels per MMcf. Current production yields about 40 barrels per MMcf. Production from Maui field (discovered in 1969) contains from 22 to 59 barrels per MMcf of condensate. The majority of the production from Maui supplies nearby urea and methanol plants. Some production is also used as feedstock for a synthetic gasoline manufacturing plant. Maui field came on line in 1979 and since then has provided most of New Zealand's gas supply. Production peaked at 635 MMcfd in the late 1980's from one 14-well platform. Plans to add another platform by 1992 are being developed.

Recent discoveries in the offshore region of the Taranaki Basin have tested at rates of more than 20 MMcfd with more than 120 barrels of oil and condensate per MMcf (GOR: 2,200 to 8,700). However, field reserves appear to be very small, and, in general, exploration results have been disappointing.

The inventory of undeveloped nonassociated gas fields in New Zealand is very small, and only three such fields were identified in this

Figure V–25 — Development Costs of Nonassociated Undeveloped Gas in New Zealand



Note: Year 2000 Oil Price Basis

study. None of the three is very large, and development costs range from less than $0.25 per Mcf for Kupe South (200 bcf) because of its high condensate yield, to nearly $20 per Mcf for Kawau (200 bcf) because of its location 160 miles offshore the South Island in extremely deep water (Figure V–25).

Total undeveloped nonassociated sales gas in New Zealand is estimated to be about 0.4 tcf.

NIGERIA

Exploration for oil in Nigeria was spurred by surface seeps in the early 20th century. The first large commercial field was discovered at Oloibiri in 1955. Most Nigerian production comes from fields in the marshy Rivers Region and offshore the eastern half of the country. Almost all announced discoveries of nonassociated natural gas have been onshore. The largest population center, Lagos, is in the western end of Nigeria, 220 miles away from the main producing areas. A natural gas pipeline to Lagos only recently has been completed, despite discussion starting in 1978. Gas from the Utorogo field will be the primary source of gas for transmission to Lagos. In the past, the majority of associated gas has been flared and there has been little development of nonassociated reservoirs. In 1987, about 80 percent of Nigerian gas production was flared.

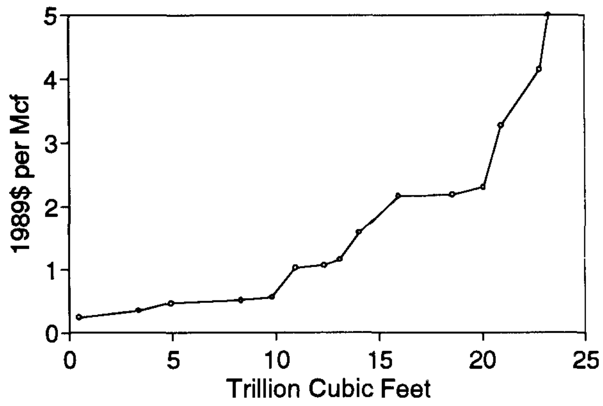
Although the government has stated a goal of developing a natural gas infrastructure to reduce waste of associated gas, it has been relatively unsuccessful in its efforts to date. The domestic natural gas use that has been developed utilizes mostly nonassociated gas production of independent oil companies operating in Nigeria. The government has placed stringent regulations on the sale and ownership of associated gas by private companies.

Nigerian fields typically contain numerous stacked reservoirs, both oil and gas, within a single field. Reservoirs typically are highly porous Tertiary sandstones, and depths range from 5,000 to 14,000 feet. Individual wells initially can produce 5 to 12 MMcfd. Condensate yields generally are in the range of 12 to 30 barrels per MMcf. Gas plant shrinkage is expected to be rather high because of the high proportion of heavy hydrocarbons in the gas. An average 8.0-percent shrinkage was assumed in this report. Most of the fields identified in this report as containing nonassociated gas have been developed for their oil reserves.

Reserves estimates in this report assume the nonassociated gas reservoirs within a developed oil field have not yet been developed. Total undeveloped nonassociated natural gas reserves in Nigeria are estimated to be about 29.0 tcf. The largest field included in this report is the Soku field, discovered in 1958. The field is producing because of its very large crude oil reserves, but nonassociated gas reserves are estimated at 3.3 tcf. Development costs are estimated to be about $0.35 per Mcf.

Development costs are relatively high in Nigeria for several reasons. The lack of infrastructure and distance from any oilfield equipment manufacturing area raises the cost of any operations or materials. In addition, most fields are located in the marshes of the Niger delta. Production equipment and plant construction costs were raised 50 percent because of Nigeria's location and lack of infrastructure, and an additional 60 percent because of the marsh location. Drilling costs were raised by the same amount. Platform costs were doubled because of the great distance from construction yards and the lack of management and support industry. Pipeline costs were raised 80 percent for all of the reasons stated above.

Figure V–26 — Development Costs of Nonassociated Undeveloped Gas in Nigeria



Note: Year 2000 Oil Price Basis

Pipeline cost calculations assume a new nonassociated gas pipeline is laid to Qua Iboe, Escravos, Bonny, or Port Harcourt for processing and export. Refineries, petrochemical plants, fertilizer plants, and export facilities are located in the Port Harcourt-Bonny area.

Total nonassociated sales gas available from Nigeria is estimated to be about 23.9 tcf. Costs of gas development vary widely, distributed evenly between $5.00 per Mcf and $0.25 per Mcf (Figure V–26).

NORWAY—NORTH OF 62 DEGREES

The first oil discoveries offshore Norway were made in the late 1960's in the Norwegian North Sea. Extensive exploration and development has continued since then, primarily for oil objectives. All production to date has come from developments in the North Sea, though development plans for Draugen, the first oil field likely to be developed in the Haltenbanken area, are moving forward. This report has concentrated on the reserves and development costs of fields in the Norwegian and Barents Seas because no development plans exist for discoveries in these areas, and they are the most likely source of uncommitted gas for export to the United States.

During the 1980's, significant oil and gas discoveries were made offshore mid- and northern Norway in the Haltenbanken (Norwegian Sea) and Tromsoflaket (Barents Sea) regions. This section of the report deals with the discoveries made north of 62 degrees. Only fields with significant amounts of nonassociated gas are included. Oil fields with gas reinjection programs have not been included.

Norwegian oil and gas development is conducted by both private companies and the state oil company, Statoil. All production is offshore in the sedimentary basins of the Norwegian Continental Shelf. All Norwegian gas is exported, currently supplying about 12 percent of total Western European consumption. Total reserves offshore Norway, as estimated by the Norwegian Petroleum Directorate, are more than 60 percent gas. Thirty-eight percent of these gas reserves are estimated to lie in the mid-Norway and Barents Sea areas, north of 62 degrees latitude. This includes the Haltenbanken and Tromsoflaket regions in the Norwegian Sea and the disputed Svalbard zone in the Barents Sea. Unlike production in the North Sea regions, which is exported via pipeline to St. Fergus, Scotland, or Zeebrugge, Belgium, through the Zeepipe pipeline project (under construction), the fields in the remote areas north of 62 degrees most likely will be pipelined to shore near Trondheim and processed onshore. Most fields are in very deep water (deeper than 300 m), and any pipeline must cross the rough seafloor of the Norwegian Trench and the nearshore fjords. The water is ice-free year-round in both the Norwegian and Barents Sea, except for occasional icebergs in the far north.

The Haltenbanken area fields are about 150 miles northwest of Trondheim and are mostly gas, except for the Draugen oil discovery (EUR 428 MMbbl) and the Heidrun oil/gas discovery (EUR 549 MMbbl, 1.3 tcf). These two fields will be the first to be developed, with Draugen slated to commence production in 1993. Plans for Heidrun, the first field with significant gas production likely to be developed in the Haltenbanken area, have been approved. Heidrun development plans include a concrete tension-leg platform (TLP) and a gas pipeline to shore at Tjeldbergodden. Gas production will supply a $400 million methanol plant capable of producing 840,000 tons per year. Heidrun oil production will be tanker-loaded. The Heidrun platform will be oversized in order to accommodate production from future developments in the area. The largest gas fields in the area, Smoerbukk (EUR 2.3 tcf) and Midgard (total gas reserves 4.2 tcf, of which about 2.8 tcf is nonassociated), do not yet have firm development plans. Agat, a gas discovery just south of the 62nd parallel about 140 miles north of Troll, is included in this section of the report. Reserves in the Haltenbanken area are equally split between oil and gas (1.68 Bbbl, 8.5 tcf).

Discoveries in the Tromsoflaket area of the Barents Sea are clustered about 100 miles northwest of Hammerfest. Fields in this area are nearly all nonassociated gas and no development plans have been made yet. The largest fields, Snoehvit (EUR 2.6 tcf) and Askellad (EUR 2.1 tcf), have been considered as the base for an LNG export project, but low gas prices in the United States, the most likely market, have rendered these plans uneconomic. Barents Sea discoveries have been mostly nonassociated gas (41 MMbbl, 8.8 tcf).

Twenty fields have been included in the northern Norway section of the World Gas Resource Cost data base. Nearly all these fields lie in water depths well over 600 feet and are assumed to be developed with TLP's. Haltenbanken fields exhibit high porosity and permeability and flow potential of up to 100 MMcfd per well. Initial well deliverabilities used in this report are in the range from 15 to 25 MMcfd. Condensate yield ranges upward from 25 barrels per MMcf. Liquids production also is very high (more than 50 barrels of NGL per MMcf). Most oil fields have large gas caps that will be available for future blowdown. Total undeveloped nonassociated gas reserves north of 62 degrees are estimated to be about 18.2 tcf.

Field developments in the Norwegian offshore utilize a wide range of options. Conventional steel platforms, large concrete gravity-base structures, subsea manifolds linked to nearby platforms, and floating or tension-leg platforms have all been used for field developments. Heidrun will employ a concrete tension-leg platform tied to the rocky seafloor of the Haltenbanken, with tanker loading of oil and condensate. Draugen will use a concrete monotower. Saga's preliminary plans for Midgard also include a concrete monotower. "Traditional" concrete gravity-base platforms used in Norwegian oil field developments cost roughly five times conventional steel platforms. Their common use in Norwegian fields has been as an anchor for areawide developments and as a means of storing large volumes of liquids. As the offshore infrastructure grows and technology improves, smaller platforms (including conventional steel and concrete monotower), and subsea developments become more common.

Excluding pipeline costs, recent cost estimates for concrete monotower developments are similar to the conventional platform cost estimates used in this study. This study's cost estimates are consistent with what the Norwegians have termed "minimal" developments in the past. This report assumes new Norwegian North Sea gas field developments will tie into the existing gas pipeline grid and platform construction will be optimized for minimal manning requirements. Haltenbanken and Tromsoflaket developments are assumed to utilize similar platform concepts, with fields in each area sharing in the cost of a common gas trunkline to shore. The onshore terminus of the trunkline is assumed to connect to either an overland pipeline to Sweden, or to a LNG or methanol plant and tanker loading facility. Although few firm plans have been made, gas export development schemes appear to favor onshore liquefaction rather than construction of large offshore plants.

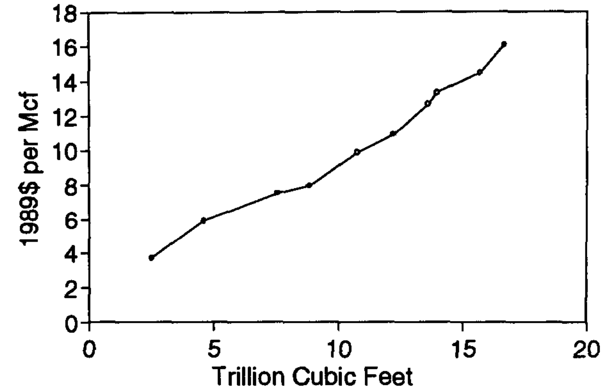
This study has assumed conventional steel platforms will be utilized in moderate water depths and steel tension-leg platforms will be used in deeper waters. Most fields in the Halten-banken and Tromsoflaket are in very deep water (deeper than 300 m), and any pipeline must cross the rough seafloor of the Norwegian Trench and nearshore fjords. The water is ice-free year-round in both the Norwegian and Barents Sea, except for occasional icebergs in the far north. Northern Norway conventional platform and platform topsides costs are based on estimates for North Sea gas fields, with an additional location factor of 33 percent added to Barents Sea fields because of the very remote location and corresponding increase in fabrication, equipping, and installation costs. Tension-leg platform costs are based on Gulf of Mexico deepwater TLP costs with a separate accommodations TLP (as used at Veslefrikk). A location factor cost increase of 70 percent for TLP's is used to raise U.S. Gulf estimates to estimated Haltenbanken costs. A factor of 133 percent was used for Barents Sea estimated costs. Total topsides costs for the TLP's are assumed similar to a single conventional platform.

Drilling costs are based on use of a jackup rig or platform rig for all wells except subsea completions, which require a semisubmersible. All deepwater fields are assumed to require about a quarter of the wells to be satellite subsea completions. Additional costs of $15.5 million per well are used to reflect the costs of subsea wellheads, and the average per-well costs of a subsea manifold, flowlines, risers, and control umbilicals. An additional 33 percent was added to drilling operations in the Barents Sea.

As mentioned earlier, Saga has released preliminary cost estimates for Midgard development. Excluding costs of a pipeline to Frigg (Saga's preferred development plan), and assuming gas is processed to sales quality at Midgard, Saga has estimated a concrete monotower development will cost about $1.75 billion (11.1 billion NKr). This study's cost estimates, including 50 percent overhead for a conventional platform with subsea satellite wells, is about $1.73 billion, or about $2.2 billion for development utilizing a pair of TLP's as in this study's other deepwater estimates. Given the uncertainty in drilling plans and overhead requirements, this estimating procedure appears to yield a reasonable approximation of total development costs. Midgard development with a conventional platform ($1.73 billion) was assumed for inclusion in the data base.

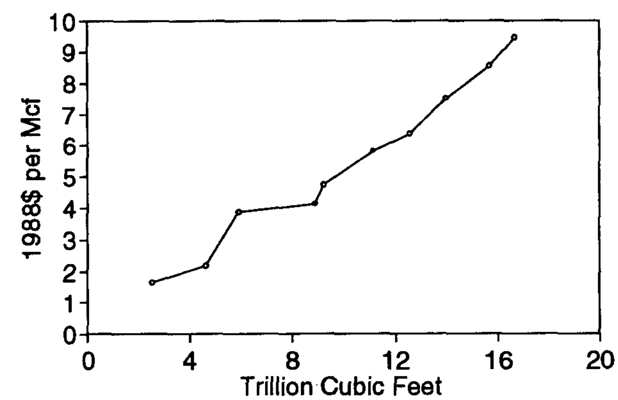
Haltenbanken and Tromsoflaket developments are assumed to require pipelines to tie into a common trunkline to Tjeldbergodden/Trondheim or Hammerfest, respectively. Because of the deepwater, ice-scoured seafloor, and remoteness, pipeline costs were assumed to be twice that of other offshore areas. A pair of gas and condensate pipelines from the Haltenbanken fields to shore was assumed to cost about $500 million; pipelines from the Barents Sea fields to Hammerfest about $400 million. As in the North Sea section of this report, costs of onshore receiving terminals, offshore riser or compression platforms, or pipeline tie-ins have not been estimated.

Figure V–27 — Development Costs of Nonassociated Undeveloped Gas in Arctic Norway



Note: Year 2000 Oil Price Basis

Figure V–28 — Development Costs of Nonassociated Undeveloped Gas in Arctic Norway (Zero Royalty Case)



Note: Year 2000 Oil Price Basis

Total nonassociated sales gas available from fields north of 62 degrees is estimated to be about 16.7 tcf. Development costs under the same conditions used in the other countries range from a minimum of $3.70 per Mcf to $16.00 per Mcf (Figure V–27).

A second calculation for Norwegian gas was made assuming a zero royalty rate (versus 40 percent in the rest of the costs presented here). This may represent the cost of development in Norway more realistically because of the concessions the government is making in recognition of the high cost of development offshore Norway. In this case, development costs range from $1.66 per Mcf to $9.46 per Mcf. In any case, the arctic Norwegian gas is the most expensive source of gas studied in this report (Figure V–28).

OMAN

Oman, in contrast to most other countries in the region, is not a member of OPEC and has allowed foreign companies to explore for and sometimes operate oil and gas fields in its territory. The first commercial discovery of oil in Oman was not made until 1962. The largest productive formations are oil-bearing limestone structures located in the central section of Oman. Gas fields are distributed throughout the country, primarily in the middle and northern portions of Oman. The northern tip of Oman is separated from the rest of the country by the Oman mountains and territory of the United Arab Emirates. Several large nonassociated gas fields are located in the Persian Gulf offshore of the northern region (Musandam), which straddles the offshore border with Iran. The Bukha field in this area has recently been slated for development.

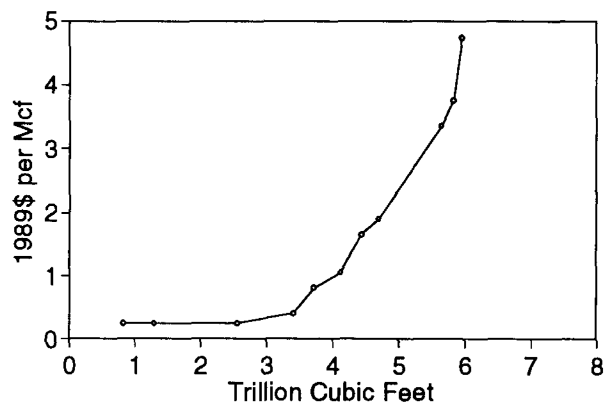
Numerous relatively small gas discoveries were made in Oman throughout the 1980's, generally in established producing areas. Many of the nonassociated gas fields are in shallow sandstone formations. In addition, many oil fields contain nonassociated gas reservoirs. Individual wells do not appear to have extremely high flowrates, with the exception of a few large fields such as Bukha. Condensate yields are fairly high.

In partnership with operators such as Occidental, Wintershall, Chevron, and Amoco, Oman has pursued a steady exploration and development program. The government of Oman has emphasized development of a national gas grid and has retained exclusive rights to revenues from gas. An offshore methanol plant to process gas from Bukha or nearby oil fields is scheduled for startup in 1991. The plant will produce 1,300 to 2,200 tons per day (41 to 61 MMcfd) of methanol. Another large discovery in Omani waters, West Bukha, is believed to be part of a structure that extends from an earlier discovery in Iranian territory. Any development of this field depends on a unitization agreement with Iran.

Most of the fields identified in this report are in established producing areas of Oman. Fields in Oman are much smaller and deplete much more rapidly than fields in the neighboring United Arab Emirates and Saudi Arabia. It has been assumed that existing gas pipelines will be able to handle the production of gas from these fields. The only pipeline investments included are costs to construct gas and condensate lines to the nearest major trunkline of the Omani system. Production from the offshore fields of the Musandam Peninsula is assumed brought ashore at Bukha.

Undeveloped nonassociated gas reserves identified here total 6.45 tcf, of which 6.1 tcf is estimated to be marketable as sales gas. The largest single field included is Bukha, with nonassociated gas reserves of about 1,000 bcf. Estimated development costs are less than $0.25 per Mcf of sales gas because of its high condensate production. Yibal, a large onshore field, is estimated to cost $0.41 per Mcf to develop. Most of the fields in Oman are estimated to cost less than $2.00 per Mcf to

Figure V–29 — Development Costs of Nonassociated Undeveloped Gas in Oman



Note: Year 2000 Oil Price Basis

develop because of their proximity to existing infrastructure and significant condensate production (Figure V–29).

PAKISTAN

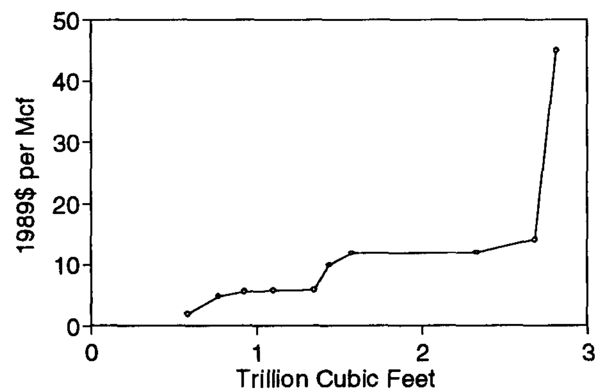
Pakistan produces both oil and gas but still imports about 75 percent of the oil it consumes. The majority of production comes from fields located in two areas: the northern part of the Indus Basin southwest of Rawalpindi (where Pakistan's largest oil fields are found) and the southern portion of the Indus Basin, along the Indus River, where several large nonassociated gas fields are located. To date, the largest gas fields have been found in the Jacobabad-Sukkur region, with smaller accumulations found closer to the river delta.

During the 1980's, exploration activity shifted from the northern Punjab and Potwar regions to the southern Sind area. Numerous small gas discoveries have been made by foreign operators as well as the state's Oil and Gas Development Corporation. The government has plans to extend the already well developed Pakistan gas transmission infrastructure to more remote regions of the country. Smaller gas fields are commonly developed for use in local industry, while larger fields are tied into the national transmission grid that links Karachi and Islamabad to the producing areas. Gas prices in Pakistan have been kept low by the government ministries that control pricing at all levels of production and distribution in the country. Recent efforts have been made to bring gas prices up to competitive international fuel prices to provide incentives for exploration and production. The government has also discussed plans to import gas from Iran or Qatar to supplement domestic production.

Pakistan produces about 1.4 bcfd, and recent estimates place natural gas as the supplier of about 35 percent of the country's energy demand. In general, condensate yields are fairly high. The Dhodak field, a large field in west-central Pakistan, may be developed initially for its condensate and liquids, with dry gas reinjected for future production. A large portion of the gas accumulations in Pakistan contain significant amounts of CO_2 and nitrogen (N_2). The presence of these nonhydrocarbon gases has delayed development of many fields. Little offshore exploration success has been reported.

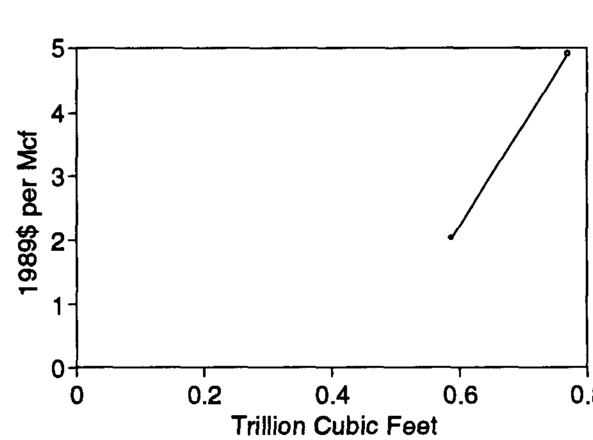
To bring gas to a port, it has been assumed that all production is brought to Karachi on the Arabian Sea. Most fields, representing about 75 percent of the reserves identified in this report, are assumed to utilize a new 350-mile trunkline along the western bank of the Indus River. Equipment costs and pipeline construction costs are assumed to require a 50-percent premium over U.S. costs because of infrastructure and terrain difficulties.

Figure V–30 — Development Costs of Nonassociated Undeveloped Gas in Pakistan



Note: Year 2000 Oil Price Basis

Figure V–31 — Development Costs of Nonassociated Undeveloped Gas in Pakistan (Truncated at $5 per Mcf)



Note: Year 2000 Oil Price Basis

Most of the undeveloped nonassociated gas reserves identified in Pakistan would be very costly to develop and bring to a port. The largest undeveloped gas fields are either in the remote western provinces (Dhodak and Jandran) or have extremely high nonhydrocarbon gas content (Khairpur and Uch). Consequently, the unit cost per Mcf of sales gas is estimated to be more than $5.00 for the purposes of this study (Figures V–30 and V–31). Total identified undeveloped nonassociated gas in Pakistan is about 6.3 tcf, only 2.8 tcf of which is estimated to be available for gas sales.

PAPUA NEW GUINEA

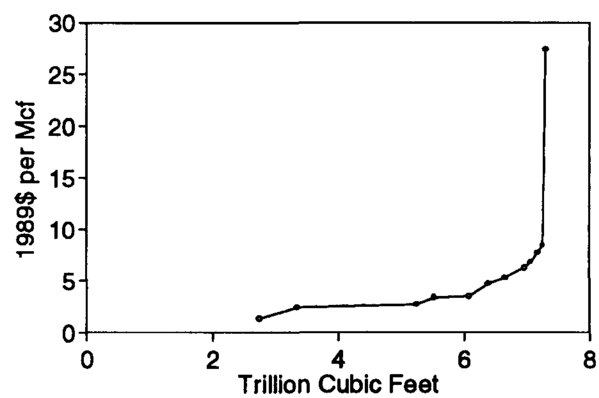
Significant oil and gas discoveries have been made throughout Papua New Guinea interior highlands and southern foothills and in the Gulf of Papua. Onshore fields are folded sandstones, while offshore fields tend to be marine carbonate structures. Several foreign producers operate exploration programs in Papua New Guinea, but development of discoveries has proceeded slowly because of the difficult terrain and lack of infrastructure or markets.

As of early 1991, no commercial production has commenced in Papua New Guinea, but several fields are slated to come on-line in the next few years. The Katubu project, which will initially include the Iagifu-Hedinia fields oil production, has been formally approved for development. This project includes an oil export pipeline extending to an offshore tanker loading berth in the Gulf of Papua. The Hides gas field, 50 miles northwest of Iagifu, will be utilized to supply fuel for electrical power for a gold mining operation. That project is planned for startup in late 1991.

Drilling costs in Papua New Guinea are very high, with most onshore exploration to date supplied by helicopters. Well costs were increased in this analysis to a level similar to Nigerian costs. A premium of 140 percent was added to development well costs because of mountainous, jungle-covered terrain and lack of infrastructure. Equipment and pipeline costs were increased 75 percent for the same reasons, similar to the increases that were used in the analysis of arctic regions. An increase of only 25 percent was made to offshore platforms because of their location in the relatively calm Gulf of Papua and proximity to Far Eastern fabrication facilities.

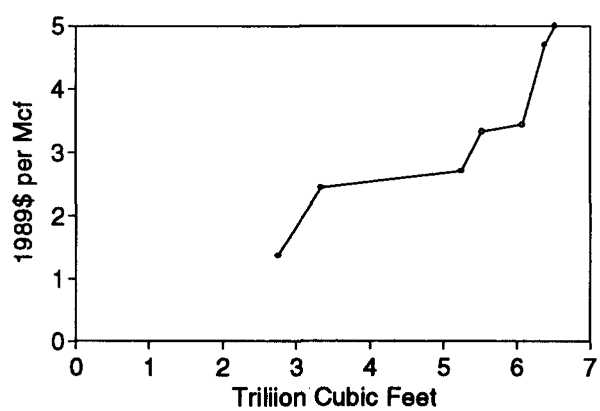
Roughly two-thirds of the fields identified here, including the Iagifu-Hedinia onshore fields and the offshore Pandora discovery, were assumed to be tied into a pipeline to the Kerema area on the Gulf of Papua. The remainder of discoveries to date, including Juha and Hides, were assumed to produce to Daru Island on the southwest coast of the Gulf. As in other remote developments, pipelines were the greatest cost

Figure V–32 — Development Costs of Nonassociated Undeveloped Gas in Papua New Guinea



Note: Year 2000 Oil Price Basis

Figure V–33 — Development Costs of Nonassociated Undeveloped Gas in Papua New Guinea (Truncated at $5 per Mcf)



Note: Year 2000 Oil Price Basis

of development in these fields. Estimated development and transportation costs ranged from about $1.37 per Mcf to more than $27.00 per Mcf, with the majority of reserves in the under-$3.50-per-Mcf range (Figures V–32 and V–33). Pandora, the largest gas discovery to date in Papua New Guinea (3.0 tcf), has estimated development costs of $1.37 per Mcf. The large onshore discovery at Hides has estimated development costs of $2.71 per Mcf.

Total identified undeveloped nonassociated gas in Papua New Guinea is about 8.6 tcf, of which 7.3 tcf is estimated to be available for gas sales.

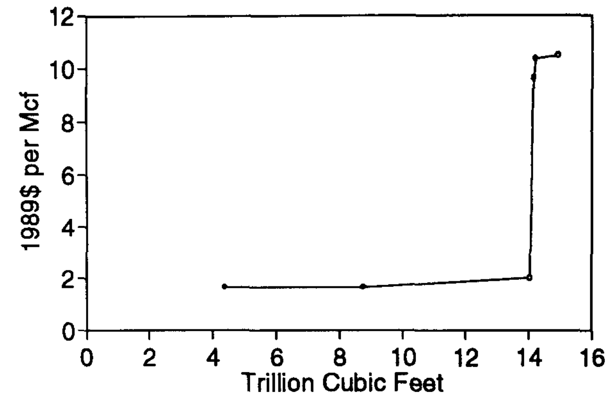
PERU

Peru's hydrocarbon reserves have been found in three areas of the country: the coastal Talara Basin, the offshore Talara Basin, and the eastern jungle regions, including the Marauan-Montana Basin and Corrientes Shelf areas. The continental shelf and coastal producing belt are narrow folded zones that contain primarily oil accumulations in complexly faulted fields. The largest producing fields are now located in the Amazonian jungle provinces, with discoveries throughout the north-south length of the country. These fields are several hundred miles from the Pacific and separated from the coast by the Andes.

The jungle region has also yielded the largest nonassociated gas discoveries in Peru. The discoveries at Aguaytia, San Martin, and Cashiriari are expected to yield from 54 to 84 barrels of condensate per MMcf. Petroperu, the national oil company, has developed plans to produce at Aguaytia, in the central jungle, for liquids production and local gas use, with over half the gas production to be reinjected. These plans are currently suspended because of guerilla activity in the area. The San Martin-Cashiriari discoveries in the south-central jungle are the basis for plans for a pipeline to Lima, but implementation has been delayed because of financial and contractual problems.

Petroperu is hindered by cash-flow problems that are caused by domestic price controls and foreign exchange problems. The government has recently stated a policy objective of attracting foreign investment in oil and gas exploration and development, but internal

Figure V–34 — Development Costs of Nonassociated Undeveloped Gas in Peru



Note: Year 2000 Oil Price Basis

political opposition may delay any contractual reforms. Peru is nominally self-sufficient in crude oil production, but some imports are required to balance refinery runs. Production has declined 30 percent since the mid-1980's.

Equipment and pipeline installations have been assumed to require a 50-percent premium in coastal areas of Peru, and a 75-percent premium in jungle locations. Offshore platforms are assumed to require a 60-percent premium because of earthquake risks. Production from the jungle fields is assumed to be transported to the Lima area for export, and all fields are assumed to share in the cost of a trunkline from the Camisea area to the coast. The offshore fields in the north are assumed to produce to a facility in the Tumbes area.

Although the undeveloped fields in Peru are in extremely remote and expensive areas, the unit cost of development may be moderate because of the large reserves and high liquids yield attributed to the fields. Most of the reserves identified in this report are estimated to cost less than $2.00 per Mcf to develop and transport to a port (Figure V–34). Total identified nonassociated undeveloped gas in Peru is estimated to be about 17.1 tcf, of which 14.9 tcf is estimated to be available for sales gas.

QATAR

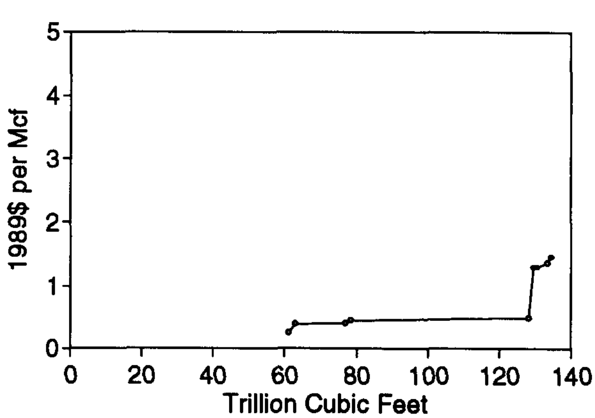
Oil was discovered in the onshore Dukhan Field in Qatar in 1939. All other oil and gas discoveries have been in offshore waters surrounding the peninsula. The vast majority of Qatar's gas is located in the offshore North Field, with at least 150 tcf of recoverable gas in Permian limestone Khuff Reservoirs at depths from 7,000 to 13,000 feet. Similar to other Khuff deposits in the Persian Gulf, the Khuff in North Field contains significant amounts of CO_2 and H_2S. Test data indicate CO_2 volume may range up to 10 percent, and H_2S up to 6 percent. Condensate yield may range from 4 to more than 40 barrels per MMcf. Well productivity is very high. For this report, initial production of 50 MMcfd per well was assumed.

Several other fields in Qatar contain large amounts of gas in nonassociated reservoirs or in gas caps, most notably the Idd el Shargi northern dome Khuff formation (3.8 tcf, discovered in 1960) and the Maydan Mazham Field area and Izhara formations (3.6 tcf, discovered in 1963). Total undeveloped nonassociated gas reserves in Qatar have been estimated in this report at 160.8 tcf.

The first phase of development of North Field is under way, with first deliveries of gas expected in 1991. The first phase is intended to supply 800 MMcfd of gas from 16 wells for domestic use. Later expansion is expected to supply other states in the Gulf Cooperation Council and possibly LNG markets in the Far East. Gas liquids produced in the first phase are expected to be about 40,000 barrels per day. The field is located under Qatar concessions formerly held by Shell and concessions currently held by a group led by Wintershall, and extends across the Persian Gulf median line into Iranian waters. Total possible reserves are believed to be as much as 300 tcf. Sales gas from the fields reservoirs is estimated to cost from $0.26 to $0.41 per Mcf to develop based on year-2000 liquid values.

The only cost adjustment made to Qatar investments is a 25-percent addition to the cost of production equipment and gas plant construction. Total nonassociated sales gas available from Qatar is estimated to be about 133.1 tcf, the majority of which will come from North Field at development costs below $0.50 per Mcf (Figure V–35).

Figure V–35 — Development Costs of Nonassociated Undeveloped Gas in Qatar



Note: Year 2000 Oil Price Basis

SAUDI ARABIA

Saudi Arabia's vast reserves of oil and natural gas originally were discovered by predecessors of Chevron, Texaco, Exxon, and Mobil on Aramco concessions granted in the 1930's and 1940's. The government gradually nationalized the operations, until the Aramco concessions became 100 percent Saudi-owned in 1980. The state oil company, still named Aramco, has recently made significant discoveries in areas outside the original concession area, most notably in the Empty Quarter south of Riyadh. Exploration still is in the early stages in these areas. The majority of Saudi production comes from offshore fields and fields in a narrow band within a couple of hundred miles of the Persian Gulf coast.

Saudi Arabia contains by far the world's largest accumulation of oil reserves and a significant amount of associated gas. The majority of the oil is contained in the Jurassic limestone reservoirs of the Arab formations. Nonassociated gas is produced primarily from the Khuff formation at 12,000 to 17,000 feet. Khuff gas contains as much as 11 percent N_2, 6 percent CO_2, and significant amounts of H_2S. The Khuff contains extremely corrosive fluids and abnormally pressured reservoirs. The productivity of individual Khuff gas wells is 50 MMcfd plus. One well in the Uthmaniyah region of

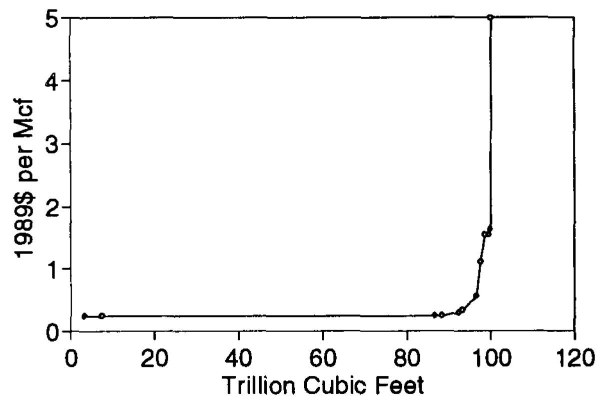
Ghawar field tested at rates of 130 MMcfd. The Khuff extends across the Persian Gulf and onshore under the coastal areas of Saudi Arabia. The full extent of Khuff deposits onshore is not yet known, but the formation appears to thin and pinch out at some point inland.

The Master Gas System, created to support the large Saudi petrochemical industry and the growing residential demand for gas, is designed to utilize 95 percent of the associated gas that would be produced with oil output of 12.5 MMB per day, about 3.5 to 4.5 bcfd. Saudia Arabia's OPEC quota on crude oil production limits the volume of associated gas supply, which has caused problems in meeting domestic gas demand for air conditioning and desalinization plants, especially during the summer. Present gas demand can be met entirely by associated gas only if production is at 7.5 MMB per day. Moreover, domestic gas demand is expected to rise 90 percent by the year 2000. In 1987 domestic gas use averaged more than 2.0 bcfd.

Saudi Arabian Basic Industries Corporation (SABIC) is expanding methanol and methyl tertiary butyl ether (MTBE) capacity in anticipation of rapidly increasing demand in the 1990's. By yearend 1989, Saudia Arabia is expected to be capable of producing 2.1 bcfd of nonassociated Khuff gas for internal consumption. Additional deliverability of 400 MMcfd from the Abqaiq field gas cap has been developed for peak demand gas requirements.

Total undeveloped nonassociated gas reserves in Saudi Arabia have been estimated in this report at 121.5 tcf. This includes the majority of the estimated Khuff reserves underlying the Ghawar field, the world's largest oil field. Although production capacity of nonassociated gas in Saudi Arabia now is about 2.1 bcfd, even at full capacity that production could be satisfied by as few as 40 gas wells with reserves amounting to about 7 tcf. That is only about 6 percent of the country's total estimated nonassociated reserves. For these reasons, the majority of Saudia Arabian nonassociated gas was classified as undeveloped in this study. This report assumes undeveloped nonassociated gas in the Ghawar Khuff alone is about 95 tcf.

Figure V–36 — Development Costs of Nonassociated Undeveloped Gas in Saudi Arabia



Note: Year 2000 Oil Price Basis

Condensate production is fairly high from Saudi nonassociated gas reservoirs. An average yield of 40 barrels per MMcf was assumed in this study. Gas plant liquids were estimated to average about 1.8 percent of production. Based on the year-2000 liquids prices used in this report, Ghawar field Khuff formation gas could be developed with the sales gas bearing no costs. An opportunity cost of $0.25 per Mcf was used in the supply-cost curves.

Other significant accumulations of undeveloped nonassociated gas occur in the Abqaiq field Khuff formation (5.0 tcf estimated nonassociated gas), the Berri field Khuff (5.0 tcf estimated nonassociated gas), and the Qatif field Khuff (4.0 tcf estimated nonassociated gas).

The only adjustment made to Saudi Arabian investments is a 25-percent increase to the cost of production equipment and gas plant construction. Total nonassociated sales gas available from Saudi Arabia is estimated to be about 99.4 tcf, the majority of which can be developed for less than $0.50 per Mcf (Figure V–36).

TRINIDAD AND TOBAGO

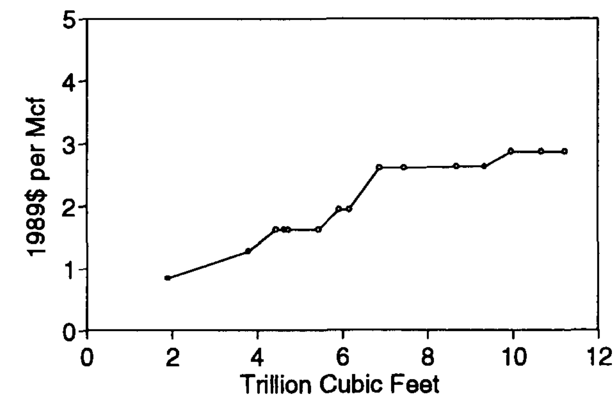
Trinidad's oil production industry dates from the 19th century, when numerous small oil fields were discovered onshore and placed into production. The geology of Trinidad is similar to eastern Venezuela because the southern part of the island is a continuation of the Maturin Basin, and the northern part is a continuation of the Venezuelan Andes. All production to date has come from the island of Trinidad and the waters surrounding it. The island is characterized by an intricate system of folding and faulting, and the petroleum geology is dominated by complex stratigraphy and small accumulations.

Significant amounts of nonassociated gas were discovered in the Miocene sandstones offshore Trinidad in exploration programs through the 1970's and 1980's. Reservoirs in these fields are highly faulted with numerous noncommunicating sand stringers and fault blocks. For these reasons, decline rates tend to be relatively high here, similar to the U.S. Gulf Coast. An average 15-percent-per-year decline for individual wells was assumed in this study. Initial well deliverability ranges from 12 to 30 MMcfd, and condensate yield averages approximately 25 barrels per MMcf.

The country still produces plenty of crude oil, more than enough to satisfy local demand, and little development of gas reserves has taken place. All of the nonassociated gas reserves included in this study are from offshore fields discovered since 1970. Water depths range from 160 to 550 feet. Reservoir depths range from 5,000 to 17,000 feet. No reports of significant sour gases were found, and plant shrinkage was assumed to average about 1.7 percent. Total undeveloped nonassociated gas reserves in Trinidad have been estimated in this study at 11.9 tcf.

The two largest fields included in our development cost estimates are the Poinsettia and Dolphin fields, each with reserves estimated at about 2.0 tcf. The cost of development for these fields is $0.85 per Mcf and $1.28 per Mcf, respectively. Exploration to date seems to indicate most fields offshore Trinidad contain several hundred bcf each, and cost of development is similar. The costs for each field estimated in this report generally are close together and vary primarily because of a field's proximity to other fields and the resultant opportunity for shared costs.

Figure V–37 — Development Costs of Nonassociated Undeveloped Gas in Trinidad and Tobago



Note: Year 2000 Oil Price Basis

The only cost adjustments made to Trinidad investments are a 60-percent increase to offshore platform costs because of earthquake risks. Total nonassociated sales gas available from Trinidad and Tobago is estimated to be about 11.2 tcf, all of which can be developed for less than $3.00 per Mcf (Figure V–37).

UNITED ARAB EMIRATES—AJMAN, DUBAI, UMM AL QAWAIN, RAS AL KHAMAIH, SHARJAH

The United Arab Emirates (U.A.E.) consists of seven kingdoms joined together in a political confederation, but whose petroleum exploration and production is carried out separately. All of the emirates have control over some offshore waters, and most have some offshore production. The capital of the U.A.E., Abu Dhabi, is discussed separately in this report.

Field distribution among the remaining emirates is very similar to that of Abu Dhabi. Nonassociated gas fields are found at various depths in the Thamama, Mishrif, Arab, and Khuff formations. Little demand internally exists for gas, and some reservoirs are produced for their condensate production. The first oil discovery outside of Abu Dhabi was the Fateh field in Dubai in 1966. Subsequent exploration yielded discoveries in all the kingdoms through the 1970's and 1980's. Sharjah and Dubai contain the largest gas reserves found to date.

Condensate production generally is in the 60-to-100-barrels-per-MMcf range in most of the gas reservoirs in the U.A.E. As a result, few of these gas deposits are left undeveloped. Initially, gas production was flared, but domestic consumption and reinjection has reduced flaring to less than 15 percent of produced gas. Total undeveloped nonassociated gas reserves in the U.A.E., excluding Abu Dhabi, have been estimated to be 9.6 tcf in this report. Gas plant shrinkage is estimated to be a little under 3.5 percent on average. Nonhydrocarbon gases generally are about 5 to 6 percent, except in the Khuff, which contains up to 20 percent CO_2, N_2, and H_2S. Initial well productivity was estimated to average 10 to 20 MMcfd.

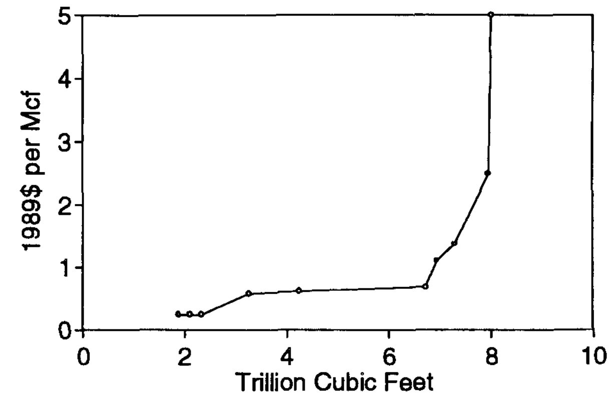
The largest U.A.E. reservoir included in the study is the Fateh field Khuff in Dubai. Estimated undeveloped nonassociated gas in that formation is 3.2 tcf. The field is located in 160 feet of water; near Fateh Island. Sales gas from the field is estimated to be 2.45 tcf, with development costs of $0.69 per Mcf.

Other major nonassociated gas deposits included in the study are the Sharjah Sajaa field 14,500-foot formation (1.2 tcf, discovered in 1980), the Dubai Margham field Thamama formation (2.1 tcf undeveloped, discovered in 1982), and the Ras al Khamaih A-Structure field Ilam-Mishrif formations (1.1 tcf, discovered in 1972).

Portions of Sajaa and Margham were included in this report even though production has been initiated from those fields. Production from Margham started in 1984, with a capacity of about 400 MMcfd. The undeveloped reserves estimate used here is about 70 percent of the field's total reserves. Sajaa field production started in 1982, at about 400 MMcfd. Initially, all gas production was flared until the 1983 construction of an LPG plant and gas distribution network. Production is assumed to be from the Thamama formation, with estimated reserves of 6 tcf. Sajaa Thamama reserves were not included in the report.

The only adjustment made to U.A.E. investments is a 25-percent increase to the cost of

Figure V–38 — Development Costs of Nonassociated Undeveloped Gas in the United Arab Emirates



Note: Year 2000 Oil Price Basis

production equipment and gas plant construction. Total nonassociated sales gas available from the U.A.E. excluding Abu Dhabi is estimated to be about 8.0 tcf, the majority of which is priced below $1.00 per Mcf (Figure V–38).

UNION OF SOVIET SOCIALIST REPUBLICS (COMMONWEALTH OF INDEPENDENT STATES)

At the time of this writing, the constituent republics of the former U.S.S.R. are forming independent governments. These republics are forming the Commonwealth of Independent States, which will coordinate some economic and military matters of common interest. Oil and gas mineral rights will be controlled by the separate republics. These republics are Armenia, Azerbaijan, Belarus, Georgia, Kazakhstan, Kirgistan, Moldavia, Russia, Tadzhistan, Turkmenia, Ukraine, and Uzbekistan.

During the 1980's, Soviet gas production increased rapidly, from about 15.4 tcf in 1980 to more than 28 tcf in 1990. Total gas reserves in the republics (former U.S.S.R.) as of January 1, 1991, were estimated to be 1,600 tcf, about 38 percent of the world total, according to the *Oil and Gas Journal.* The Gas Ministry of the former U.S.S.R. claimed its gas resources totaled more than 40 percent of the world's total. Soviet gas use rose in step with production and made up about 37 to

40 percent of the country's primary energy consumption. The two largest gas fields developed to date in the former U.S.S.R., Urengoi and Yamburg, both in Western Siberia, each contain reserves greater than the entire North Sea. Russia, Azerbaijan, Kazakhstan, and several of the other republics formerly comprising the Soviet Union have long been major oil exporters and have also become very important sources of gas for Europe. Gas exports accounted for more than 11 percent of production in 1987 (nearly 3 tcf). Urengoi has been exporting gas to Western Europe since 1984, while Yamburg has recently commenced production for export.

As is true for oil production in the former U.S.S.R., most of this increased gas production is coming from fields in the Tyumen province of Western Siberia. The vast territory of the former U.S.S.R. encompasses several major producing regions in various stages of exploration and development maturity. Basins in European Soviet republics and around the Caspian Sea were first developed more than 100 years ago. Several Paleozoic basins located west of the Ural Mountains from the Ukraine to the Arctic in western Siberia were first developed during the 1930's and provided most of the Soviet Union's production after World War II. The Mesozoic West Siberia Basin (east of the Urals) contains many fields that have been brought on-line during the last 20 years as exploration has moved further north and further away from the main consumption areas in Europe. The West Siberia Basin is geologically similar to the North Sea but is approximately six times the areal extent.

Russia and the other republics also have significant hydrocarbon resources in their extensive offshore continental shelf areas. The continental shelf encompasses approximately 6 million square kilometers. For comparison, the Western and Central Gulf of Mexico shelf plus slope areas of the United States cover only about 360,000 square kilometers. The offshore areas of the former U.S.S.R. include the inland Caspian and Black Seas, the far eastern Asia Okhotsk and Bering Seas, and the seas along the northern arctic shoreline. The majority of the Continental Shelf areas lie offshore Russia. Most of the offshore areas are only lightly explored, especially in the Arctic, but very large discoveries of gas have already been made in the Kara Sea and Barents Sea areas offshore Tyumen province.

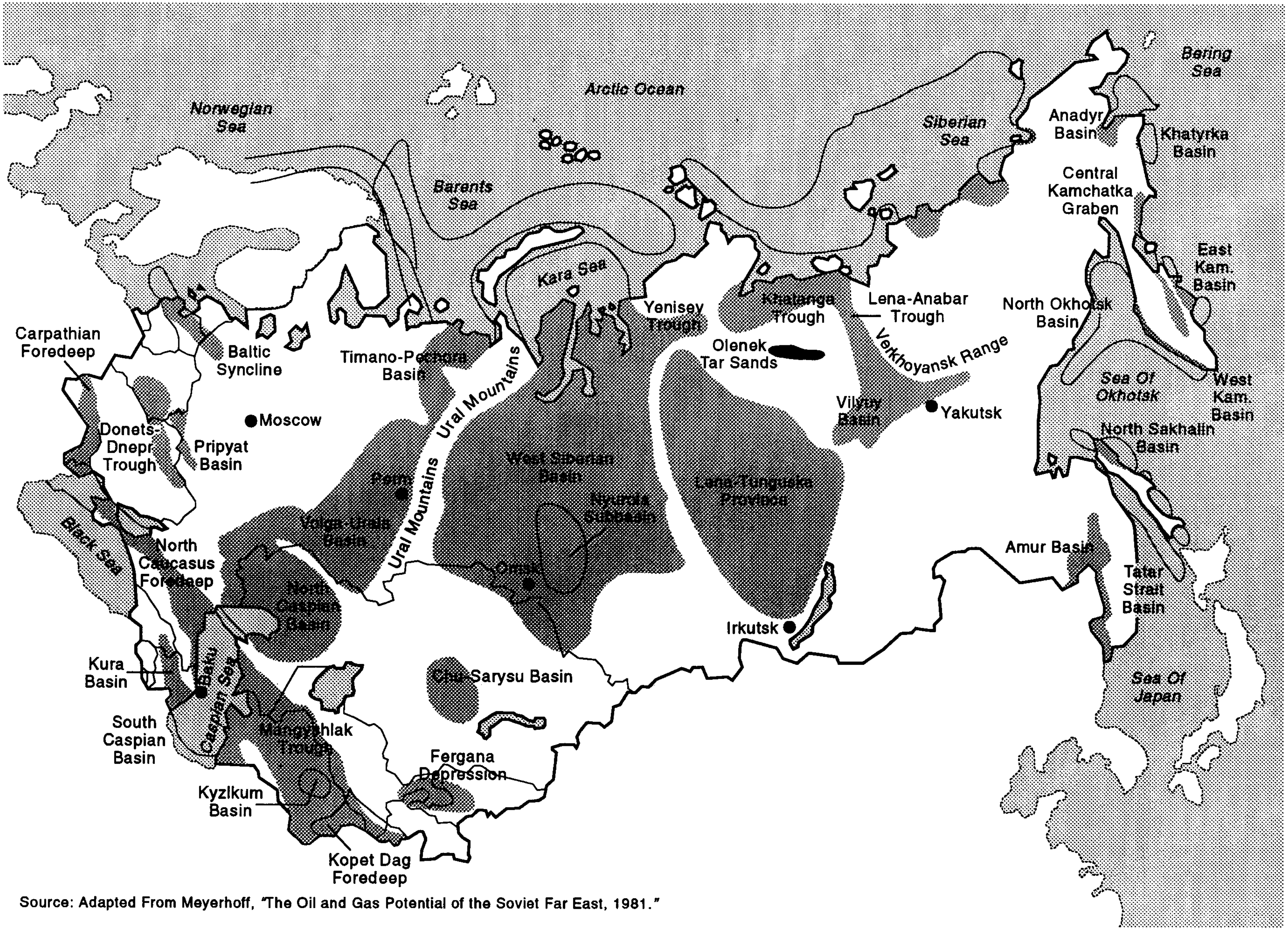
Production data concerning the former Soviet Union was not easily available in the past, so depletion rates are difficult to estimate. Some of the large gas fields that have been developed since World War II appear to have R/P ratios in the range of 30 to 60 years. The oil and gas production industry has been experiencing increasing difficulties in development and distribution of reserves discovered in increasingly remote and operationally difficult regions. These problems are probably due to the extremely remote regions of some of these developments, production equipment manufacturing and maintenance shortages, the general difficulties of the Soviet infrastructure and economy, as well as technology deficiencies. Dynamic changes took place in 1991 as joint ventures with foreign companies became more commonplace and more of the former U.S.S.R.'s oil and gas production was sold for hard currency in the world market. Recently, Turkmenia became one of the first republics to open oil and gas leases for competitive bid.

Several regions, including the North Caucasus Foredeep (near Volgograd and Stavropol), the Ukraine, and the onshore areas bordering the Caspian Sea, are in a relatively mature stage of exploitation, with infrastructure and costs similar to northern Alberta, Canada, or Australia. The majority of Eastern Russia and regions outside established oil production areas surrounding the Caspian Sea, including most of Siberia and the offshore, is lightly explored, with costs and infrastructure similar to the Canadian Arctic or the Norwegian Barents Sea.

Figure V–39 and Table V–6 outline the locations and characteristics of the former Soviet Union's constituent republics' main producing areas. The following paragraphs highlight some of the outstanding features of each area.

The enormous West Siberian Basin (Russia) underlies the steppes from the Urals to the Yenisei River (about 1,200 miles) and covers an area of about 1.75 million square kilometers onshore, and about one-quarter million square kilometers offshore in the Kara Sea. The majority of the basin underlies sparsely

Figure V–39 — Petroleum-Bearing Basins in the Former U.S.S.R.



Source: Adapted From Meyerhoff, "The Oil and Gas Potential of the Soviet Far East, 1981."

Table V–6 — Geologic Basins in the Former U.S.S.R.

Basin Name	Political Province(s)	Geologic, Production Characteristics	Exploration Level	Surface Description	Number of Large Undeveloped Gas Fields in Basin (# / bcf)
Carpathian Basin	W. Ukraine	Folded overthrust sediments, highly faulted primarily Eocene sandstones, oil and gas fields	Mature	Well-developed infrastructure 50 degrees north latitude	
Donets-Dnepr Trough	Ukraine	Sedimentary trough trending northwest-southeast, primarily gas, Jurassic sandstone, Permian carbonate	Mature	Well-developed infrastructure 48 degrees north latitude	4 / 660
Baltic Syncline	Kaliningrad	Small oil accumulations Middle Cambrian sandstones Carboniferous sandstones	Mature	Baltic coast	
Pripyat Basin	Belarus	Fractured, faulted carbonates, underlying salt, primarily oil	Mature	Well-developed infrastructure 50 degrees north latitude	
Timano-Pechora Basin	Nenets, Komi	Upper Devonian sandstone, Lower Carboniferous carbonates, oil and gas, including major gas fields	Moderate	Primarily north of 64 degrees, east of Urals from Ukhta to Barents Sea	11 / 9,800
	Offshore Nenets, Barents Sea, Novaia Zemlia Island	Lower Jurassic, Cretaceous sandstones, very large gas accumulations	Early	Novaia Zemlia Island: continuous permafrost Offshore: mostly ice free	1 / 140,000 (Offshore)
Volga Urals Basin	Perm	Permian dolomites, Lower Carboniferous sandstones/limestones, primarily small oil accumulations	Mature	East of Urals, 58 degrees north Perm Province, Udmurtia	4 / 2,900
	Tatar	Gently dipping large oilfields mainly Carboniferous sandstones	Moderate/ mature	Primarily east of Volga, central Tatar Republic (55 degrees north latitude)	
	Kuybyshev	Oil and gas, faulted structures, Shiguli-Puhatschev uplift, Permian limestones, Carboniferous/Devonian sandstones	Mature	Near Volga at Kuybyshev (in Tatar)	
	Bashkiria	Kama-Bielaya depression, northwest-southeast structural trend, Lower Carboniferous/Devonian sandstones, Permian limestones, primarily oil	Mature	East of Tatar Republic	

Table V–6 — Geologic Basins in the Former U.S.S.R. (continued)

Basin Name	Political Province(s)	Geologic, Production Characteristics	Exploration Level	Surface Description	Number of Large Undeveloped Gas Fields in Basin (# / bcf)
Volga Urals Basin (continued)	Orenburg	Devonian, Carboniferous, Permian oil reservoirs, Krasny Kholm (Orenburg) gasfield in Lower Permian limestone	Moderate/ mature	Southeast of Tatar (52 degrees north latitude)	
	Saratov	Large gas fields in Middle Carboniferous sandstones, oil in Carboniferous/ Devonian sandstones	Mature	Saratov area, both sides of Volga	
	Volgograd	Mostly gas fields in Jurassic sandstones, Devonian/ Carboniferous sandstones	Mature	East of Volga, between Saratov and Volgograd (50 degrees north latitude)	
Pre Caspian (North Caspian)	Kazakhstan	Small oil/gas fields in Triassic/Jurassic sand-stones above saltdomes, large gasfields in Permian carbonates under salt horizon	Moderate/ Mature	North/northwest shore regions of Caspian Sea, Kazakhstan SSR, Astrakhan	2 / 1,100
North Caucasus Foredeep	Krasnodar, Stavropol, Crimea	Oil/gas production from sandstones and carbonates in Miocene-Oligocene formations	Mature	Between Black and Caspian Seas, 45 degrees north latitude	3 / 1,100
	Dagestan, Kalmyk Georgia	Mostly oil production from folded Miocene/Cretaceous sandstones	Mature	Western shore of Caspian Sea 44 degrees north latitude	
Baku District	Azerbaijan, Georgia	Complex stratigraphy, crescent-shaped folds slumping toward Caspian Sea, mostly oil from Pliocene sandstones	Mature	Western shore of Caspian Sea, Baku area, 40 degrees north latitude	1 / 200
Mangyshlak Trough	Turkmenia	Eastern shore extension of Baku District folded sediments, oil and gas from Pliocene sandstones	Moderate	Eastern shore of Caspian Sea	41 / 19,000
North/South Caspian	Caspian Sea Offshore	Northern Caspian Jurassic/ Cretaceous sediments, Southern Caspian Pliocene sediments	Moderate	Deeper waters off Apsheron Sill in early stages of exploration	

Table V–6 — Geologic Basins in the Former U.S.S.R. (continued)

Basin Name	Political Province(s)	Geologic, Production Characteristics	Exploration Level	Surface Description	Number of Large Undeveloped Gas Fields in Basin (# / bcf)
Kizyl-Kum Basin	Uzbekistan	Large gas accumulations, Cretaceous sandstones	Moderate/ Mature	Hilly desert, southeast Uzbekistan 40 degrees north latitude	3 / 2,600
Fergana Depression	Kazakhstan, Kirglzia	Oil production from Oligocene, Eocene, Cretaceous limestones and sandstones	Moderate/ Mature	Mountainous, southeast Kazakhstan	1 / 1,100
Kopet Dag Foredeep	Tadzhikistan	Smail oil accumuiations	Moderate/ Mature	Mountainous, along border with Afghanistan	
West Siberia	South: Tyumen, Omsk, Novosibirsk, Tomsk, Krasnoyarsk	Lower Cretaceous, Jurassic sandstone domal structures, mostly oil (including Samotlor), some gas	Moderate	Entire basin covers 1.75 million square kilometers onshore—generally featureless steppe. Southern perimeter stretches from Tyumen to Krasnoyarsk	72 / 550,000
	West: Tyumen, Nenets	Jurassic sandstones, oil and gas structures, some stratigraphic oii accumulatlons	Moderate	West: Urals foothills to Ob River 58 to 64 degrees north latitude	
	North: Tyumen, Nenets	Lower Jurassic, Cretaceous sandstones, very large gas accumulations, including Urengoi	Early	North: Tyumen to Surgut (58 to 61 degrees north latitude), sporadic permafrost. Surgut to Nadym River delta (61 degrees north latitude to Arctic Circle). Seasonal discontinuous thawing	
	Offshore: Nenets, Kara Sea	Very large gas accumulations, Jurassic/Cretaceous sediments	Early	Yamal, Taz, Taimyr Peninsulas: continuous permafrost. Offshore: year-round ice	2 / 150,000 (Offshore)
Yenisey Trough	Lena-Tunguska Nenets	Western edge of Eastern Siberia Platform, gas/ condensate sandstone structures over salt, oil stratigraphic traps	Early	Southwest Taimyr Peninsula: continuous permafrost	

Table V-6 — Geologic Basins in the Former U.S.S.R. (continued)

Basin Name	Political Province(s)	Geologic, Production Characteristics	Exploration Level	Surface Description	Number of Large Undeveloped Gas Fields in Basin (# / bcf)
Vilyuy Basin	Lena-Tunguska Yakutia	Eastern edge of Eastern Siberia Platform, gas/condensate production from Triassic/Jurassic sandstones	Early	East of Verkhoyansk Mountains, near Yakutsk, 62 to 65 degrees north latitude	4 / 9,100
Irkutsk Amphitheater	Lena-Tunguska Irkutsk	South and west of Eastern Siberia Platform, small gas and oil deposits in Liassic sandstones	Early	South and west of Lena River, from Yakutsk to Irkutsk (Arctic Circle to Lake Baikal)	1 / 1,500
Khatanga Trough	Nenets Offshore: Laptev Sea	Triassic/Permian reservoirs over salt domes, oil discoveries to date	Early	East of Taimyr Peninsula, permafrost, year-round ice offshore	
Anadyr/ Khatyrka Basins	Far East Siberia	Generally gas-prone Pliocene, Miocene, Eocene discoveries to date	Early	Mostly offshore Pacific/Bering Seas (64 degrees north latitude), winter ice floes	
North Okhotsk Basin	Sea of Okhotsk	Cenozoic sandstone folds, small oil accumulations found to date	Early/ Moderate	Mostly offshore west of Kamchatka Peninsula, winter ice floes	
North Sakhalin Basin	Sakhalin island	Miocene sandstone folds, oil and gas accumulations found on- and offshore	Moderate	Offshore discoveries east of island, 53 degrees north latitude, mostly ice free	4 / 16,400

populated regions with arctic climates. Political regions are the provinces of Tyumen, Nenets, and Komi. The largest known oil field in Russia (Samotlor) and the largest known gas field in the world (Urengoi, with EUR of about 280 tcf) are located in this region. Reservoirs appear to have moderate porosities but very high permeabilities and flowrates. Condensate yields are generally high. Water-drive gas reservoirs are reported in many fields. Large gas hydrate accumulations are known, and some production is reported. The largest undeveloped nonassociated gas field in West Siberia included in this study is Bovanenko, located on the Yamal Peninsula in far northern Tyumen Province. Bovanenko reserves are estimated to be at least 122 tcf. Bovanenko development drilling started in 1988 with initial production originally slated for sometime in 1991. Cost estimates in this report assume the pipeline proposed to run the length of the Yamal Peninsula is built and available for transportation of gas from the numerous discoveries on Yamal. Production from any field north of Taz (78.9 degrees) or Yamburg (75.6 degrees) is assumed to be transported through pipelines proposed but not yet constructed for those areas. Other undeveloped fields are assumed to be able to transport production through the existing pipeline grid. Nine other fields in Tyumen included in this report have estimated reserves of more than 10 tcf. In total, Tyumen Province reserves account for about 90 percent of all undeveloped nonassociated gas reserves identified in this report. Nenets Province contains numerous large, relatively recent discoveries that have undergone extensive delineation drilling, but have not yet been placed on production. Petroconsultants reserves estimates for fields in this area appear to be somewhat generous based on physical descriptions in the data base. Production is assumed to be carried by pipeline to a location on the coast near Kumzhinskoye, though this area is surrounded by pack ice much of the year. Exploration to date indicates that very large productive structures are also located offshore.

Some of the other onshore areas in the non-European regions of the former U.S.S.R. have been heavily explored for oil, but only in the last couple of decades have they seen extensive gas development. These areas include the central Asian Republics of Turkmenia, Tadzhikistan, Kazakhstan, and Uzbekistan, which share geologic features with neighboring Iran and Afghanistan. Turkmenia, which also borders the Caspian Sea, has numerous large gas fields that have been developed onshore, including Shatlyk (EUR estimates range from 127 to more than 300 tcf) and Sovetabad (EUR about 45 tcf). Condensate yields are generally somewhat low. Turkmenia's geology is part of the same structure, the Mangyshlak Trough, that contains the extensive deposits of the Azerbaijan region. The offshore area of Turkmenia is in a relatively early stage of development.

The Barents Sea coast of Russia is part of the prolific Timan-Pechora Basin, which contains several large discoveries in a trend that includes Kolguyev Island. Little exploration has been performed to test for offshore fields in the area. Shtokmanovskoye, a 1988 discovery 350 miles northeast of Murmansk, is believed to contain 88 to 140 tcf of gas, making it the second largest offshore gas field in the world, after Qatar's North Field. Water depth is reportedly up to 985 feet. A joint venture including CONOCO, Norsk Hydro, and Neste Oy has announced preliminary plans to start production from the field before 2000. The Kara Sea, east of Novaia Zemlia, is surrounded by very large discoveries onshore the Yamal Peninsula. The icebound waters of the Kara have permitted little exploratory drilling, but work to date has identified numerous very large structures that have a high likelihood of containing gas. The former Soviet Government indicated that Rusanovskoye field, about 100 miles west of the northern tip of the Yamal Peninsula, may contain as much as 280 tcf of gas. If this figure is correct, it may be the largest gas field in the world. Leningradskaya, about 50 miles south of Rusanovskoye, is also described as a "supergiant" discovery. Risked reserves of 140 tcf and 10 tcf have been assigned to these two fields for purposes of this analysis. The icebound waters of the arctic seas bordering Siberia (Laptev, East Siberian, Chukchi, and Bering) are virtually unexplored. The deeper waters of the Caspian and Black Seas are also in early stages of exploration.

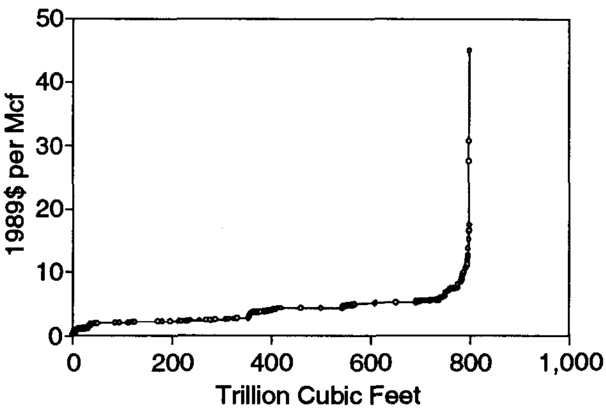
The edges of the vast Eastern (or Central) Siberian Platform contain lightly explored structures that are favorable for hydrocarbon accumulations. The platform covers an area of about 1.75 million square kilometers and is ringed by the Yenisei, Irkutsk, Khatanga, and Vilyuy Basins. Production in the Soviet Far East has been concentrated on Sakhalin Island. The area is underlain by several basins containing both oil and gas, primarily onshore and offshore to the north and east of the island. The fields are typically shallow (less than 7,000 feet) sandstones. Development in the area is expected to be spurred by the completion in 1987 of a gas pipeline from Okha field to Komsomolskna-Amure. Future development may include construction of a gas pipeline to Japan or Korea.

The development costs assumed in this report are consistent with those estimated for other countries. Cost estimates are based on the typical long-run costs that would be required for an international producing company to operate a field and send production to the nearest port or major trunkline. No additional costs of bureaucratic inefficiency were added.

In general, onshore operations in developed regions of the former U.S.S.R. were assumed to require an infrastructure premium of 50 percent for equipment costs. Most new developments in the republics are in relatively remote areas in which producing operations cannot rely on the local power and transportation networks. For example, initial development of the Yamburg field required 6 days' travel time to deliver equipment from Medvezhoye field, only 125 miles to the south. Arctic regions (north of 64 degrees latitude) are far from any significant populations and present extreme weather conditions as well. These areas were assumed to require a 100-percent premium for equipment and pipeline installations. Arctic fields were also assumed to consume an additional 2.0-percent of sales gas in gas gathering line (including delivery to trunklines) cooling for permafrost protection. This is similar to estimates used in the Canadian Arctic. Normal fuel consumption in fields is assumed to be 2.5 percent of residue gas.

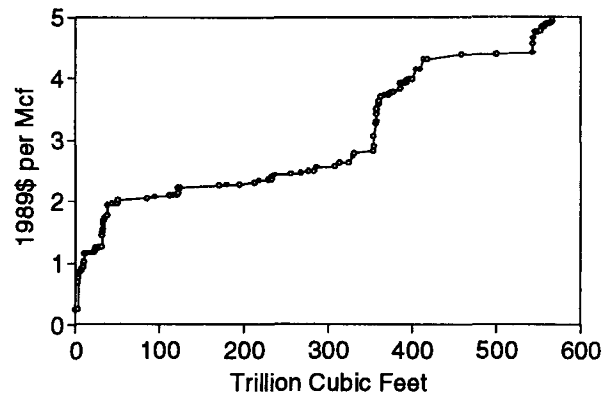
The gathering system for each field is assumed to be extended to the nearest existing or proposed gas trunkline or coastal city. A unit (dollars per Mcf) transportation charge was added to account for expansion of the

Figure V–40 — Development Costs of Nonassociated Undeveloped Gas in the Former U.S.S.R.



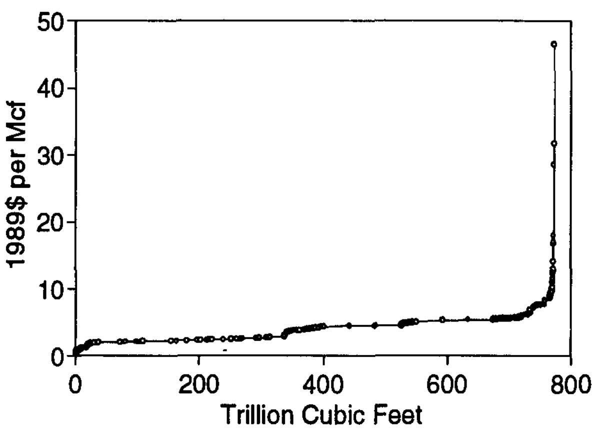
Note: Year 2000 Oil Price Basis

Figure V–41 — Development Costs of Nonassociated Undeveloped Gas in the Former U.S.S.R. (Truncated at $5 per Mcf)



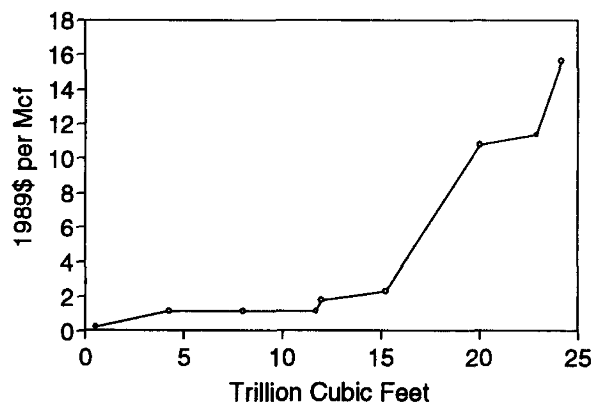
Note: Year 2000 Oil Price Basis

Figure V–42 — Development Costs of Nonassociated Undeveloped Gas in the Former U.S.S.R. (European Delivery)



Note: Year 2000 Oil Price Basis

Figure V–43 — Development Costs of Nonassociated Undeveloped Gas in the Former U.S.S.R. (Pacific Delivery)



Note: Year 2000 Oil Price Basis

Soviet continental transmission grid from remote production areas to the coast. No additional charge was added to development costs in areas such as Azerbaijan or Sakhalin. The charge was estimated to be $0.60 per Mcf for fields in Kazakhstan and Turkmenia, and $1.00 per Mcf for fields in Komi, Nenets, Gydan Peninsula, Tomsk, Tyumen, and in the Barents and Kara Seas. The estimated charge is based on the amortized cost of a 52-inch line carrying 1 tcf of gas per year over 1,500 and 2,000 miles, respectively. These distances are based on transmission to a port on the Black Sea. Additional fuel use of 3 percent of sales gas was assumed for transmission. The approximate location of existing and proposed pipelines were taken from Pennwell's International Petroleum Encyclopedia maps. Some extremely remote fields where only local pipelines exist, such as those in Yakutia in eastern Siberia, were assumed to share in the cost of a pipeline to the Sea of Okhotsk (to Magadan or Vladivostock) on the Pacific Ocean.

Offshore arctic wells, platforms, and artificial islands were estimated to cost the same as investments in the Canadian Beaufort Sea or Norwegian Barents Sea. In areas where year-round ice is a problem, which includes most of the arctic seas except the Barents, subsea wells drilled from temporary artificial ice islands or surface wells drilled from permanent gravel islands were assumed. Deeper water fields (greater than 65-feet water depth) in arctic waters were assumed to require ice-resistant steel or concrete platforms. Costs for gravity base platforms in these fields were extrapolated from gravel island construction costs.

Reserves estimates for individual fields were mainly derived from Soviet government estimates reported in Petroconsultants or industry literature. If such an estimate were not available, an estimate of recoverable gas was made using data contained in Petroconsultants reservoir descriptions. Some very large fields identified in this report, including the supergiant discoveries in the Barents and Kara Seas, were not in Petroconsultants as of mid-1990. Preliminary reserves estimates for these fields have been used; these probably include some significant probable reserves. Numerous smaller gas discoveries are listed in Petroconsultants but no reserves or geologic descriptions are available. Most of these small discoveries were not included in the inventory of undeveloped gas fields. Also excluded from this report were all presently producing fields. These include some of the giant fields such as Urengoi, Yamburg, and Taz (Tyumen); Sovetabad (Turkmenia); Karachaganak (Kazakhstan); and Sredne-Vilyuyoskoye (Yakutia), that probably have excess capacity that is not fully exploited. However, long-term exports to Europe (or Japan) will most likely preclude any dedication of reserves in these fields to U.S. imports. Total raw undeveloped nonassociated gas reserves included in this study are 905 tcf. Estimated sales gas is about 798 tcf.

Estimated gas costs delivered to a trunkline range from less than $0.25 per Mcf (the assumed cost floor in this analysis) for fields in established producing areas such as Uzbekistan, Turkmenia, and Sakhalin Island, to as much as $30 or $40 per Mcf from small fields in remote areas of Russia (Siberia) (Figures V–40 through V–43). Including the transmission pipeline tariff, approximately 38 tcf may be developed and brought to a port for less than $2.00 per Mcf, approximately 353 tcf for less than $3.00 per Mcf, and approximately 556 tcf for less than $5.00 per Mcf. The large onshore Siberian fields such as Bovanenko and Urengoi Severnyy have estimated development costs of between $2.10 and $2.60 per Mcf. The offshore discoveries in the Barents and Kara Seas have estimated costs of $4.50 to $7.50 per Mcf.

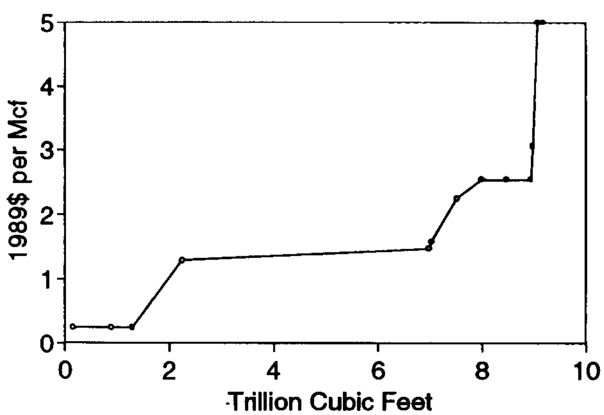
VENEZUELA

Venezuela's first oil concession was granted in 1866, and numerous shallow wells were drilled near seepages through the rest of the 19th century. After the turn of the century, fields around and in Lake Maracaibo were rapidly developed. Other major sedimentary basins in Venezuela include the Maturin Basin near the Orinoco River delta and extending offshore toward Trinidad, the Orinoco heavy-oil belt on the southern flank of the East Venezuela basin, and the lightly explored Gulf of Venezuela Basin in the west. Venezuela contains mostly oil-bearing provinces, with a few significant gas accumulations in some fields. Numerous oil reservoirs have large primary or secondary gas caps that may not have been exploited. Most of these have been excluded from this study. Seven of the ten largest gas-bearing fields in terms of estimated recoverable gas are primarily oil fields. Large gas accumulations are found in all of the previously mentioned basins, but the largest accumulation of strictly nonassociated gas reservoirs occurs in the Maturin Basin.

The recent discoveries of light oil in the western portion of the country have allowed those provinces to become self-sufficient in gas, and plans to send additional supplies of gas from the eastern fields have been changed. Major expansion of the Eastern Venezuela Cryogenic Complex, with current capacity of 800 MMcfd, is being studied. Long-range objectives are to boost domestic production of petrochemical products, which will require increased use of natural gas. Venezuela was one of the first countries to nationalize exploration and production operations. Recently, because of lagging exploration programs and a shortage of cash available for investment, the national company, Petroleos de Venezuela SA, has begun negotiations with foreign companies interested in Venezuelan operations.

Most recent gas discoveries have been offshore, mainly in the eastern portion of the country. Light-oil and high-GOR reservoirs have been discovered in Lake Maracaibo. Most associated gas production is consumed or reinjected for pressure maintenance in oil reservoirs. Several fields with very high GOR's have been included in this report as nonassociated gas fields. Large gas caps overlying thin saturated oil rims are suspected to exist in these fields (Dragon, EBC, and SLE). Most fields have very high condensate yields, averaging more than 40 barrels per MMcf. Gas plant liquid production is highest in the onshore fields in the east (assumed to be 14 percent in this report), while offshore fields near Trinidad were assumed to have a shrinkage after processing of about 1.7 percent. Nonhydrocarbon gases generally are less than 3 percent of raw gas production. Total undeveloped nonassociated gas reserves in Venezuela have been estimated in this report at 9.9 tcf.

Figure V–44 — Development Costs of Nonassociated Undeveloped Gas in Venezuela



Note: Year 2000 Oil Price Basis

Well deliverability ranges from just a few million cubic feet per day to more than 45 MMcfd in some of the newer offshore fields. The largest nonassociated gas formation included in this report, the offshore Patao field in 350 feet of water, has an estimated 5.0 tcf of reserves. Development cost is estimated to be about $1.48 per Mcf. Most offshore fields carry gas development costs of between $2 and $3 per Mcf, while gas from onshore fields can be developed at a much lower cost because of the location and liquids production.

Cost adjustments have been made to production equipment, gas plants, and platforms. A 20-percent increase has been added to equipment and gas plants because of the location and infrastructure requirements. A 60-percent increase has been added to offshore platforms because of the risk of earthquake loads offshore Venezuela. Total undeveloped nonassociated sales gas available from Venezuela is estimated to be about 9.2 tcf, most of which can be developed for less than $3.00 per Mcf (Figure V–44).

YEMEN

The first hydrocarbon discoveries in Yemen were not made until very recently. Hunt Oil Company pioneered exploration work in the territory formerly comprising North Yemen during the early 1980's. Development of fields accelerated in the late 1980's in both Yemens. After unification in 1990, Yemen has continued to grant concessions to foreign operators.

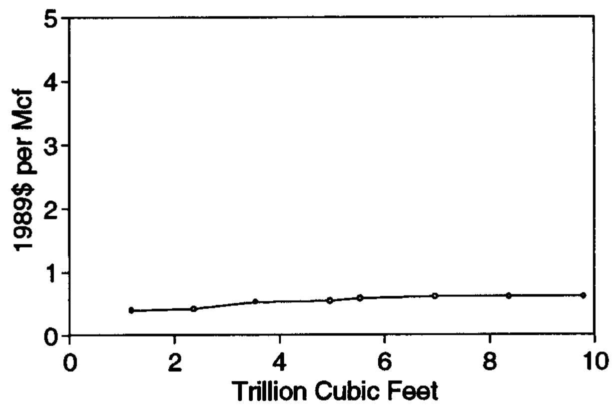
Hunt's Alif field discovery in 1984 was the first field to be placed on production (an earlier discovery by Agip in South Yemen in 1982 was not developed.) Production from Alif commenced at the end of 1987. Several other discoveries have been made since then, including some nonassociated gas fields in both North and South Yemen. Almost all current oil production is exported.

All hydrocarbon accumulations in Yemen appear to be concentrated in the Ma'rib-Jawf Basin, a deep sedimentary sandstone basin in the desert beyond the mountainous central part of the country, on the southern edge of Saudi Arabia's Empty Quarter. The area straddles the former border of South and North Yemen.

Most of the oil fields in Yemen produce large amounts of associated gas. Currently there is no outlet for this gas, and much of it is reinjected or flared. The government would like to initiate domestic use of gas to displace other local fuel sources, especially wood. Azal and Raydan fields are much gassier than Alif and may contain some nonassociated gas. The large gas accumulations at As'ad Al-Kamil and Yah may consist of both nonassociated gas and large gas caps. The very large reserves figure for Yah estimated by Petroconsultants cannot be independently confirmed, and this study has reduced it to a value similar to the other Yemen gas fields. Yemen Hunt has announced plans to cycle gas production from three recently discovered fields (Al-Rajah, Dostour Al-Wihdah, and Al-Saidah) for condensate recovery. Dry gas is to be reinjected until a market for gas develops.

For purposes of resource cost estimation, it has been assumed all fields share in the cost of a gas trunkline to Salif, near Kamaran

Figure V–45 — Development Costs of Nonassociated Undeveloped Gas in Yemen



Note: Year 2000 Oil Price Basis

Island on the Red Sea, which is the terminus of the crude-oil line from Alif field. A direct route across the mountains is about 175 miles. The estimated cost of a new gas pipeline and liquids pipeline from the fields is about $270 million. This investment has been allocated among the several fields according to their reserves.

Most of the nonassociated undeveloped gas fields identified here are in very early stages of development, and little information is available concerning their reserves extent and producing characteristics. Uniform condensate production of 30 barrels per MMcf was assumed for all fields. All of the development costs calculated for Yemen fields are less than $0.60 per Mcf of sales gas (Figure V–45). Total nonassociated gas reserves are about 10.4 tcf, of which about 9.8 tcf is marketable as gas.

APPENDIX A: A BRIEF SUMMARY OF GAS RESERVES IN ANGOLA, BOLIVIA, BRUNEI, MYANMAR, THAILAND, AND TUNISIA

To conclude this study, a quick look at the estimated gas reserves in Angola, Bolivia, Brunei, Myanmar (Burma), Thailand, and Tunisia was made. Table A–1 summarizes the remaining total gas reserves in each country as reported by the *Oil and Gas Journal* and the potential undeveloped nonassociated gas reserves that may be inferred from Petroconsultants data.

Bolivia and Brunei already have natural gas export programs in place; Thailand is studying the feasibility of exports. Angola and Myanmar are in relatively early stages of exploration for oil and gas. Both of these countries expect to discover significant amounts of hydrocarbons that will provide self-sufficiency in energy and potentially allow oil or gas exports. Tunisia currently imports gas.

No cost estimates were made for development of the unutilized nonassociated gas in each country, nor was Petroconsultants data checked for reasonableness.

ANGOLA

Angola has benefited from an active exploration program conducted by Gulf (now Chevron) over the past 2 decades. Several new discoveries have been made, and some production has been initiated. According to Petroconsultants, 13 known nonassociated gas fields are undeveloped with total gas reserves of about 2.1 tcf. Most of these reserves are contained in one field—Etele, discovered in 1975.

BOLIVIA

Bolivia has exported gas to Argentina since the early 1970's under the terms of a contract that is due to expire in 1992. Bolivia's economy is highly dependent on gas exports, and the government is negotiating further gas exports to Argentina or Brazil. Because of the long history of exports and local use, Bolivia has little undeveloped gas reserves. According to Petroconsultants, 17 known nonassociated gas fields are undeveloped, with total gas reserves of about 0.15 tcf.

Table A–1 — Estimates of Undeveloped Nonassociated Gas
(Trillion cubic feet)

Country	*Oil and Gas Journal* Total Gas Reserves (Assoc. & Nonassoc.) 1/1/91	Petroconsultants Inferred Undeveloped Nonassociated
Angola	1.8	2.1
Bolivia	4.1	0.15
Brunei	11.2	2.9
Myanmar	9.4	5.0
Thailand	5.9	7.6
Tunisia	3.0	2.0
Total	35.4	19.8

BRUNEI

Brunei has large reserves of oil and gas located beneath its small surface area, mostly offshore. The kingdom exports more than 250 bcf each year, primarily in the form of liquefied natural gas (LNG) to Japan. Nearly all of this gas is associated with oil production. Some significant nonassociated gas fields remain undeveloped. According to Petroconsultants, 13 known nonassociated gas fields are undeveloped, with total gas reserves of about 2.9 tcf.

MYANMAR

Myanmar (Burma) has recently offered new concessions to foreign operators to spur new exploration activity. Oil and gas exploration in Myanmar dates back many years to its time as a British protectorate. Most older discoveries have been developed, while some large, relatively recent gas discoveries have not yet been placed in production. According to Petroconsultants, nine known nonassociated gas fields are undeveloped, with total gas reserves of about 5.0 tcf. Most of these reserves are contained in one field—3DA, discovered in 1983.

THAILAND

Thailand has stepped up development plans for discoveries made by Unocal in the offshore Gulf of Thailand and Esso in the northern highlands. Thailand's demand for energy is growing rapidly, and gas production from the existing offshore fields has supplied much of the growth, most notably Erawan. As new discoveries have been made further from shore, Thailand has explored the possibility of LNG exports to Japan or Korea. According to Petroconsultants, 18 known nonassociated gas fields are undeveloped, with total gas reserves of about 7.6 tcf. This figure may include some or all of the reserves associated with the Pilong structure. The production split from this discovery (estimated reserves of 3.6 tcf) is the subject of negotiations with Malaysia because of its location under a disputed section of the Gulf.

TUNISIA

Tunisia apparently holds some significant gas reserves, much of which are offshore. The Miskar field, which contains about 1 tcf of gas, was discovered in 1975 but remains undeveloped because of territorial disputes with Libya and problems with project financing. Tunisia imported more than 31 bcf of gas in 1988. Discussions with Algeria regarding expansion of export pipelines through Tunisia and then offshore to Italy may spur development of these offshore fields. According to Petroconsultants, 14 known nonassociated gas fields are undeveloped, with total gas reserves of about 2.0 tcf.

APPENDIX B: OVERVIEW OF NATURAL GAS CONCESSION ARRANGEMENTS AND TAX STRUCTURES

INTRODUCTION

This appendix provides an overview of concession arrangements and tax structures for natural gas exploration, development, and production for 13 of the countries reviewed in this study. The appendix is in two parts:

- A general introduction to natural gas concession arrangements and recent trends in such arrangements.
- A table containing country-specific information on concession arrangements in 13 countries.

The focus of the concession review has been on terms for nonassociated gas. However, terms specific to nonassociated gas have not been developed or are not readily available for many of the countries covered in this study. For such countries, general petroleum concession terms are reviewed.

Concession arrangements have been identified through reviews of literature for each country. Primary sources include Barrows' *World Petroleum Arrangements 1989,* various books, and periodicals, including *Offshore* magazine, the *Oil and Gas Journal,* and *Energy Policy.*

STATUS OF NATURAL GAS CONCESSION ARRANGEMENTS

Most international exploration and development agreements are oriented toward exploration and development of oil resources. In these agreements, natural gas is usually treated in only a few sentences or clauses if at all. The references to natural gas generally state that either it does not remain part of the concession arrangement, is to be treated in the same manner as oil, or shall result in a renegotiation of contract terms.

The secondary treatment of potential natural gas discoveries in petroleum concessions and contracts results from the nature of the natural gas market. Because gas developments require a dedicated and expensive transportation infrastructure between wellhead and end-user, a natural gas industry is much more difficult to develop than an oil industry. The necessary infrastructure is difficult to justify without a guaranteed market, which in turn is hard to develop without assured supplies. This impasse results in initially slow growth of domestic markets, particularly in developing countries such as Nigeria and Malaysia. Several of the countries in this review suffer from this condition and, thus, tend not to have well-developed procedures, regulations, and contract terms for the development of natural gas. The countries with more highly developed natural gas markets, such as Algeria and Indonesia, also have the most highly developed contractual arrangements for natural gas.

Nationalization of Natural Gas Resources

A number of the countries in this study have nationalized either all or part of natural gas resource development. In countries like Saudi Arabia and Venezuela, all petroleum resources, including natural gas, are owned and developed by the state. In Abu Dhabi, all natural gas resources have been declared to be owned by the State, and the state is responsible for the development of these resources, even though private oil firms still receive standard concessions for the exploration and development of oil resources. In Algeria, the standard concession contract allows the government to assume all rights to any commercial natural gas discoveries; the concession holder is reimbursed for any expenses and may receive a previously negotiated bonus.

Nigeria, Qatar, Dubai, and Trinidad have effectively nationalized all nonutilized associated gas at the wellhead. Many of the oil exploration and development contracts in these countries explicitly transfer rights to nonutilized associated gas to the state and require the producing company to install appropriate gathering and treatment facilities when requested by the state (to be reimbursed by the state).

Gas Pricing Issues

In the countries that have not nationalized their natural gas resources, the state may still have a great impact on natural gas exploration and development interest through control of natural gas purchase prices. Several of the developing countries, such as Nigeria and Malaysia, have not yet developed consistent pricing practices for produced natural gas. Other countries, such as Argentina and Venezuela, have fixed domestic natural gas prices at low levels as a social policy.

Major gas exporters appear to be much more likely to base natural gas prices on market value than nonexporters. Norway, Algeria, and Indonesia all appear to use economic criteria when determining gas purchase prices. Ecuador also appears to base prices on market considerations.

Recent Trends in Concession Terms

Most of the countries reviewed in this report have liberalized concession arrangements in the last 5 years. Tax and royalty rates or government participation shares have been decreased in several countries, including Nigeria, Norway, Indonesia, Algeria, and others. A few countries with highly nationalized petroleum industries, such as Venezuela and Argentina, have moved toward greater deregulation and privatization. The changes have been made to encourage more exploration and development activity by the multinational oil companies. The changes are the result of several factors:

- Decreases in oil prices in the mid-1980's resulted in a sharp decrease in exploration and development expenditures by multinational oil companies. Concession arrangements have been modified to make exploration and development more attractive to these companies under lower oil prices.
- Lower oil prices have caused revenue shortages in most of the exporting countries. These countries now find it more difficult to internally fund the desired level of exploration and development activity.
- The international banks and lending institutions are no longer able or willing to loan large sums of money for petroleum exploration and development.

OVERVIEW OF DIFFERENT TYPES OF PETROLEUM ARRANGEMENTS

Types of Contracts

There are four general types of petroleum agreements offered by the countries reviewed in this study by other countries:

- Concession contracts.
- Production-sharing agreements.
- Service contracts.
- Risk service contracts.

Individual countries often use more than one of these basic types of agreements. A brief summary of each agreement type is presented below.

Concessions

A concession contract generally grants the concession holder the right to explore, drill, produce, transport, and sell petroleum from the area covered by the concession. In exchange, the petroleum company generally guarantees a minimum level of exploration, provides exploration and development capital, and pays the government royalties, income tax, and other applicable taxes on any oil or gas produced. The concession holder supplies all risk capital.

Most concessions require a certain portion of the concession area to be relinquished within specified time limits if commercial quantities of oil or gas have not been found.

Concession-type agreements are the primary types of agreements used in the U.A.E., Nigeria, Norway, and Trinidad. Other countries in the study, such as Argentina, use concession agreements on occasion. Most of the countries in this study using concession agreements allow for the government to "buy in" as an equity owner in the concession if commercial oil or gas is found.

Production-Sharing Agreements

Production-sharing agreements were developed by Indonesia in the late 1960's as a means of encouraging oil and gas exploration and development by the international oil companies while maintaining a higher degree of control over resources than was found in standard concession agreements. In the basic production-sharing agreement, the petroleum company provides all risk capital for exploration, development, and production of petroleum resources. The produced oil or gas is divided between the host government and the company based on parameters negotiated in the contract.

Production-sharing agreements generally divide production into a "cost" component and a "profit" component. The cost component of production is allocated to the company to repay the exploration, development, and operating costs associated with the project. Some of the countries reviewed in this report place upper limits on the percentage of total production allowed to fall into the "cost" component. Because of the increased risk associated with natural gas development, these cost recovery components for natural gas tend to be higher than for oil, when specific natural gas terms have been worked out.

The profit component of production is determined after payment of cost production and is divided between the host government and the contracting company based on a prearranged ratio. The prearranged ratio may be either before or after consideration of income taxes. Generally, the majority of the profit production is allocated to the host government. The share of profits from production-sharing agreements is included in Table B–1 under the heading "Government Share of Profits." The share of profit production accruing to the government is generally lower for natural gas than for oil.

Occasionally, production-sharing agreements are structured such that the government profit share increases as production levels increase. Malaysia provides a 50:50 split of profit gas for the first 2 trillion cubic feet of production, and a 70:30 split (favoring the government) for any additional gas production.

Service Contracts

A service contract is generally a nonrisk contract in which the contractor is reimbursed for all costs and is paid a fee based on costs incurred. This type of contract has been widely used by national oil companies to contract for production expertise of the private oil companies. Countries such as Saudi Arabia, Abu Dhabi, Qatar, and Venezuela use this type of contract for development, operation, and maintenance of known commercial oil and gas fields.

Most oil and natural gas produced in countries with nationalized oil and gas industries is produced under this type of contract. Generally, the contractor is paid a fee based on production level. Typical fees for Middle Eastern oil fields are around $0.10 to $0.20 per barrel of oil. (Abu Dhabi in 1980, Saudi Arabia in 1981).

Risk Service Contracts

Certain countries also use modified service contracts for exploration, where the contractor provides risk capital and is rewarded with higher fees based on production from discoveries. Basic exploration agreements in Ecuador and Argentina are of this type. Saudi Arabia also uses risk service contracts to fund exploration activity.

The primary difference between a risk service contract and a production-sharing contract is ownership of produced oil and gas. In a production-sharing agreement, ownership of production is split between the producing company and the host government, while in a risk service contract, the host government assumes ownership of all produced oil and gas and pays a fee to the producing company based on production value and volume.

Government Participation

Most of the countries included in this review retain in their contracts and concessions the right for the national petroleum company to acquire an equity interest in any commercial development resulting from the contract or concession. The minimum equity share varies

Table B–1 — Summary of Natural Gas Concession Terms by Country

Country	National Petroleum Company	Private Part. in Exp. & Dev.?	Resource Ownership	Domestic Natural Gas Price	Nature of Gas Concessions: Well-Developed Natural Gas Terms?	Nature of Gas Concessions: Gas Disc. Subject to Contract Negotiation	Contract Terms: Contract Type	Contract Terms: Gov. Participation (%)	Contract Terms: Gov. Share of Profits (%)	Taxation: Income Tax (%)	Taxation: Royalty Rates (%)	Taxation: Special Petroleum Taxes (%)	Sample of Concession Owners
Abu Dhabi	ADNOC (Abu Dhabi National Oil Company)	Yes (oil)	State (gas)	—	All gas owners and developed by State		Concession service contract	Up to 60 (oil) 100 (gas)	— 100 (gas)	60	16	—	Amoco
Algeria	Sonatrach	Yes	State	1982 marginal cost	Yes	Yes	Joint vent., prod. sharing	51–100	63 (LNG)	65–80	12.5–20	—	Total, AGIP, Anadarko
Argentina	YPF (Yacimientos Petroliferos Fiscales)	Yes YPF has sole concession for 80 % of country	State	Fixed % of oil price (27 %–50 %)	All gas discoveries may be purchased by the State.		Risk service contract	15–50	—	55	50–66 (based on oil price)	—	Mobil, Exxon, BHP Texaco, Petrobras, ...
Ecuador	Petroecuador	Yes	State	Market pricing	—	Yes	Risk service contract	59–94 (oil: varies by prod.)	71.42	12.5	0–30 (oil: varies by prod.)	—	Texaco, Esso, Arco, BP, Occidental
Indonesia	Pertamina	Yes	State	Based on economic parameters	Yes (General terms; same as oil)	—	Prod. sharing	50	32 (gas before tax)	48	16 (1st tranche production)	—	44 Companies as of 1988
Malaysia	Petronas	Yes	State	Pricing policy not yet determined	No	Yes	Prod. sharing	15+	50–70 (oil: varies by prod.)	35	10	70 % of price >base price (oil)	Shell, Esso, BP Elf
Nigeria	NNPC (Nigerian National Petroleum Company)	Yes	State	No price policy in effect	No (State assumes ownership of	—	Concession	60+	—	65–85	16.66–20	All but $2/ bbl-(oil) (85+-)	Texaco, Gulf, Elf, Shell, Phillips
Norway	Statoil Export Value	Yes	—	Set by	Yes	—	Concession	51–85 (Spitzbergen area: 10% tax only)	—	50.8	0–12.5	30 in addition to income tax	—
Qatar	QGPC (Qatar General Petroleum Company)	Yes	State	—	No (State assumes ownership of associated gas)	Yes	Prod. sharing, service contracts	—	80–90 (varies by prod.)	85 (est.)	—	—	Sohio, Amoco, BP, Total

Table B–1 — Summary of Natural Gas Concession Terms by Country (continued)

					Nature of Gas Concessions		Contract Terms			Taxation			
Country	National Petroleum Company	Private Part. in Exp. & Dev.?	Resource Ownership	Domestic Natural Gas Price	Well-Developed Natural Gas Terms?	Gas Disc. Subject to Contract Negotiation	Contract Type	Gov. Participation (%)	Gov. Share of Profits (%)	Income Tax (%)	Royalty Rates (%)	Special Petroleum Taxes (%)	Sample of Concession Owners
Saudi Arabia	ARAMCO	No	State	—	State responsible for all natural gas exploration and development		Risk & non-risk service contracts	100	100	45 (suspended)	20	—	—
U.A.E. Other	DPC (Dubai Petroleum Company)	Yes	—	—	No (State assumes ownership of associated gas)		Concession	Up to 60	—	55–85 (varies by prod.)	12.5–20	—	BP, Amoco (Dubai) Arco, Gulf
Trinidad	Trintoc Trinopec	Yes	On: Split Off: State	—	No State can preempt rights to associated gas		Concession	—	—	55	Nego-tiated	5 onshore 25 offshore	Mobil, Amoco, & Tobago
Vene-zuela	Pdvsa (Petroleos de Vene-zuela	No (Subject to 1990 revisions in Government Policy)	State	Fixed	State responsible for all natural gas exploration and development		Service Contracts	100	100	82	—	—	Shell, Exxon, Mitsubishi (Joint LNG Project)

from 15 percent in Argentina and Malaysia to up to 50 to 60 percent in most of the other countries reviewed. In Norway, equity share can range from 51 to 85 percent, depending on production volume.

The cost to the government of exercising its participation rights varies for different governments. Generally, the national petroleum company can exercise its participation rights at the time a discovery is declared commercial, by assuming an appropriate share of expended exploration and development costs. Except in Norway, the national petroleum companies do not appear to be responsible for exploration expenses not resulting in discoveries of commercial oil or gas fields.

In Algeria, all hydrocarbon activities must be carried out by companies or joint ventures where at least 51 percent of all profits will accrue to the "national undertaking." Of the countries reviewed here that have not nationalized the oil and gas industry, only Trinidad does not appear to require an option for government participation.

Royalties and Taxes

In addition to production-sharing and government participation requirements, the host governments use a variety of devices to get revenues from oil and gas production. Four standard measures are reviewed here:

- Signature and production bonuses.
- Royalties.
- Income taxes.
- Special petroleum taxes.

Signature and Production Bonuses

Several of the countries reviewed in this study include signature and production bonuses in most concession agreements. Signature bonuses are fees paid at the signing of the concession agreement. Production bonuses are payments required after certain levels of production are reached. These fees generally are negotiable depending on the perceived value of the concession and are often determined on an auction basis, with the concession awarded to the highest bidder.

Barrows' *World Petroleum Arrangements 1989* includes contract summaries with either signature or production bonus requirements for Abu Dhabi, Dubai, Indonesia, Nigeria, and Qatar.

Royalties

Royalties are payments made to the mineral rights owner (for the subject countries, that is the government). Of the countries reviewed here, Abu Dhabi, Algeria, Argentina, Dubai, Ecuador, Indonesia, Malaysia, Nigeria, Norway, Saudi Arabia, and Trinidad generally require royalties to be paid on oil and gas production. Royalties normally range from 10 to 20 percent of the gross value of production. In the last few years, several of these countries have reduced royalty rates to encourage additional exploration and development. In Norway and Trinidad, royalty rates are negotiable based on specific project economics. In Algeria and Nigeria, royalty rates vary by geographic region of the discovery, and, in Dubai, royalty rates vary with production levels. Specific royalty rates for each country are shown in Table B–1.

In Argentina, the royalty on natural gas production appears to be based on the value of fuel oil equivalent even though actual prices are much lower. As a result, the effective royalty rate in Argentina ranges from 50 to 66 percent (Davidson, Hurst, and Mabro 1988).

Income Taxes

All of the countries reviewed in this study have significant corporate income tax requirements. Nominal tax rates range from 35 percent in Malaysia to 85 percent in some of the OPEC countries. Nominal corporate income taxes for each country are included in Table B–1. There may be significant differences between nominal and effective tax rates because of a wide variety of tax deductions and credits.

Special Petroleum Taxes

A few of the countries reviewed here require payment of special petroleum taxes on profits in addition to general income tax requirements. Most of these additional taxes are designed to capture economic rent from oil production and may not be applicable to natural gas.

The nature of these special taxes varies between countries. Ecuador imposes an additional tax ranging from 0 to 30 percent of profits based on field production levels. Malaysia taxes 70 percent of the difference between a specified base price and actual prices. Nigeria allows roughly a $2.00-per-barrel profit and has a special tax to recover profits above this level after all other taxes have been paid. Norway imposes an additional 30-percent tax on petroleum profits on top of its normal corporate tax of 50.8 percent. Trinidad imposes an additional 5-percent tax on onshore production and a 25-percent tax on offshore production.

Taxation in the Norwegian Arctic. The tax scheme for much of the Norwegian Arctic deserves special note. Resource development in the Svalbard Islands (including Spitzbergen) is governed by special international treaty, which does not allow royalty or income taxes to be imposed on any resource development there. Mineral operators are only required to pay a 10-percent profits tax (*Oil and Gas Journal* 1986).

IMPACT OF TERMS ON ECONOMICS

Several example calculations of the required sales gas revenue for the same field under varying contractual and tax terms are presented in this section. In each example, the field development plan and capital cost of development have been kept constant. Project financing terms and expected return on equity have also been kept the same in all cases.

The four cases presented here are the following:

- Standard—40 percent royalty, 37.5 percent income tax after expenses, 20 percent return on equity, 40 percent debt financing at 12 percent nominal interest rate, liquids value based on $27.80 per bbl crude.
- Standard with income tax reduced to zero.
- Standard with royalty reduced to zero.
- Standard with no royalty and no income tax.

The arrangement implied by these terms is a simple concession contract, in which the operator owns all the production that accrues to its working interest, assumes all risk involved, and is free to sell production on the open market. The project economics calculated here are as a result more reflective of world market prices. No portion of production is subject to politically influenced pricing or profit controls as in some types of production-sharing contracts.

Numerous variations on the examples could be made to illustrate the effects of controls on revenues or profits that accrue to the working interest. For instance, Norway has eliminated royalties on some projects but has a higher income tax rate than the 40 percent used in the standard calculations. Many countries require sales of a portion of production to the domestic market at prices fixed by the government. Sliding scale royalties based on production rates or oil prices are employed in some areas. The extreme examples shown here should encompass a wide spectrum of supply costs possible in a free market.

Table B–2 shows the economic calculation for the example field. The field is an offshore gas discovery in moderate water depths, with estimated recoverable gas of 2.6 tcf. Condensate yield is 13 bbl per MMcf; gas plant shrinkage is 2.7 percent; and nonhydrocarbon gases make up 3.0 percent of the raw production. Daily production is 285 MMcfd. Total capital costs are $517 million (1989$). Capital costs include 5 platforms and 67 wells.

As the last page of Table B–2 shows, the required revenue per Mcf of sales gas for this field is $1.41. Liquids revenue contributes $0.59 per Mcf. Liquids revenue is calculated independently of the required total hydrocarbon revenue and is the same in all examples. Income taxes are treated as costs for the calculation of required sales gas revenue and amount to $544 million over the life of the project. Royalty payments are subtracted from the working interest share of production before taxes are paid, but they represent 108 MMcfd ($1.1 billion) of potential revenue.

Table B–3 presents the required sales revenue calculation for the example without royalty or tax payments. The 108 MMcfd of

Table B-2 — Resource Cost Calculation for Natural Gas Development Project in Indonesia
(Nominal and real 1989 dollars)

Economic Parameters		Production, Costs	
Equity Ratio	0.60	Daily Prod. Cap. (Raw MMcfd)	285
Nominal Return on Equity (%)	20.0	Nonhydrocarbon Gases (%)	3.0
Equity Term (years)	15	Condensate (bbl/MMcf)	13
		Gas Plant Conversion to Liquids (%)	2.7
Debt Ratio	0.40	Total L&P Fuel Gas Use (%)	2.5
Nominal B.T. Debt Interest (%)	12.0		
Debt Term (years)	10	Platform, Equipment Costs ($MM)	79
		Pipeline, Gas Plant Costs ($MM)	83
Inflation (%)	5.0	Well Costs ($MM)	161
Income Tax Rate	0.37	Total Number of Wells	67
Nominal A.T. Cost of Capital (%)	15.0		
Real A.T. Cost of Capital (%)	9.5	Total Capital Costs, Including Overhead	
Depreciation Period	15	(million 1989$)	517
		Debt	207
Utilization Rate (%)	95.0	Equity	310
Investment Life (years)	15		
		Annual O&M (million 1989$)	10.3
		Annual O&M = 5% of Plant/Pipeline Capital Costs, Plus $125k/Well Offshore, $40k/Well Onshore	
		Value of Crude, Cond. ($/bbl)	27.80
		Value of Plant Liquids ($/MMBtu)	4.31
		Government Royalty (%)	
		Before Payout	40.0
		After Payout	40.0

Table B–2 — Resource Cost Calculation for Natural Gas Development Project in Indonesia (continued)

(Nominal million 1989 dollars)

	Debt						Taxes							
Year	Balance	Payment (C)	Princip.	Interest (E)	Equity Return (F)	Annual O&M (G)	Deprec. (H)	Annual Taxable Income (P-E-G-H)	Tax Losses Incurred	Tax Losses Realized	Losses Carried Over	Adjusted Taxable Income	Income Taxes Paid (N)	Total Costs (C+F+G+N)
1	206.7	36.6	11.8	24.8	66.3	10.3	34.4	39.7	0.0	0.0	0.0	39.7	14.8	127.9
2	194.9	36.6	13.2	23.4	66.3	10.8	34.4	46.0	0.0	0.0	0.0	46.0	17.2	130.8
3	181.7	36.6	14.8	21.8	66.3	11.3	34.4	52.8	0.0	0.0	0.0	52.8	19.7	133.9
4	166.9	36.6	16.5	20.0	66.3	11.9	34.4	60.0	0.0	0.0	0.0	60.0	22.4	137.1
5	150.4	36.6	18.5	18.0	66.3	12.5	34.4	67.7	0.0	0.0	0.0	67.7	25.3	140.6
6	131.8	36.6	20.8	15.8	66.3	13.1	34.4	76.0	0.0	0.0	0.0	76.0	28.3	144.3
7	111.1	36.6	23.2	13.3	66.3	13.7	34.4	84.8	0.0	0.0	0.0	84.8	31.6	148.2
8	87.9	36.6	26.0	10.5	66.3	14.4	34.4	94.2	0.0	0.0	0.0	94.2	35.1	152.4
9	61.8	36.6	29.2	7.4	66.3	15.1	34.4	104.3	0.0	0.0	0.0	104.3	38.9	156.9
10	32.7	36.6	32.7	3.9	66.3	15.9	34.4	115.1	0.0	0.0	0.0	115.1	42.9	161.7
11	(0.0)	0.0	0.0	(0.0)	66.3	16.7	34.4	126.7	0.0	0.0	0.0	126.7	47.2	130.2
12	(0.0)	0.0	0.0	(0.0)	66.3	17.5	34.4	134.7	0.0	0.0	0.0	134.7	50.3	134.1
13	(0.0)	0.0	0.0	(0.0)	66.3	18.4	34.4	143.2	0.0	0.0	0.0	143.2	53.4	138.1
14	(0.0)	0.0	0.0	(0.0)	66.3	19.3	34.4	152.1	0.0	0.0	0.0	152.1	56.7	142.4
15	(0.0)	0.0	0.0	(0.0)	66.3	20.3	34.4	161.4	0.0	0.0	0.0	161.4	60.2	146.8
Total			207		995	221	517	1,459	0	0		1,459	544	2,126
Present Value														812

Table B-2 — Resource Cost Calculation for Natural Gas Development Project in Indonesia (continued)
(Real 1989 dollars)

Year	Calculated PV Costs = PV Rev: Real Total Costs ($ million)	Real Required Working Int. Revenue ($ million)	Production (bcf/Year): Total	Production (bcf/Year): Royalty	Production (bcf/Year): Working Interest	Resource Cost ($/Mcf Raw)	Required Project Revenues ($ million): Total	Required Project Revenues ($ million): Royalty	Required Project Revenues ($ million): Working Interest	Allocation of W.I. Share ($ million): Real Income Taxes	Allocation of W.I. Share ($ million): Real O&M	Allocation of W.I. Share ($ million): Real Interest	Allocation of W.I. Share ($ million): After Inc. Tax Int. & O&M
1	127.9	109.2	98.8	39.5	59.3	$1.84	181.9	72.8	109.2	14.8	10.3	24.8	59.3
2	124.6	109.2	98.8	39.5	59.3	$1.84	181.9	72.8	109.2	16.3	10.3	22.3	60.3
3	121.4	109.2	98.8	39.5	59.3	$1.84	181.9	72.8	109.2	17.9	10.3	19.8	61.3
4	118.5	109.2	98.8	39.5	59.3	$1.84	181.9	72.8	109.2	19.3	10.3	17.3	62.3
5	115.7	109.2	98.8	39.5	59.3	$1.84	181.9	72.8	109.2	20.8	10.3	14.8	63.3
6	113.1	109.2	98.8	39.5	59.3	$1.84	181.9	72.8	109.2	22.2	10.3	12.4	64.3
7	110.6	109.2	98.8	39.5	59.3	$1.84	181.9	72.8	109.2	23.6	10.3	9.9	65.4
8	108.3	109.2	98.8	39.5	59.3	$1.84	181.9	72.8	109.2	25.0	10.3	7.5	66.4
9	106.2	109.2	98.8	39.5	59.3	$1.84	181.9	72.8	109.2	26.3	10.3	5.0	67.6
10	104.2	109.2	98.8	39.5	59.3	$1.84	181.9	72.8	109.2	27.7	10.3	2.5	68.7
11	80.0	109.2	98.8	39.5	59.3	$1.84	181.9	72.8	109.2	29.0	10.3	-0.0	69.9
12	78.4	109.2	98.8	39.5	59.3	$1.84	181.9	72.8	109.2	29.4	10.3	-0.0	69.5
13	76.9	109.2	98.8	39.5	59.3	$1.84	181.9	72.8	109.2	29.7	10.3	-0.0	69.2
14	75.5	109.2	98.8	39.5	59.3	$1.84	181.9	72.8	109.2	30.1	10.3	-0.0	68.8
15	74.1	109.2	98.8	39.5	59.3	$1.84	181.9	72.8	109.2	30.4	10.3	-0.0	68.5
Total	1,535	1,637	1,482	593	889		2,729	1,092	1,637	363	154	136	985
Present Value	853	853	772	309	463		1,421	569	853	173	80	97	503

Table B-2 — Resource Cost Calculation for Natural Gas Development Project in Indonesia (continued)
(Real 1989 dollars)

Annual Balances		Volumes	Required Revenues ($ million)	Sales Gas Revenues ($/Mcf)	
	Raw Production (bcf)	98.8			
	Non-H.C. Gases (bcf)	3.0			
Gas:	Net H.C. Gases (bcf)	95.8			
	Plant Shrinkage (bcf)	2.6			
	L&P Fuel Use (bcf)	2.4			
	Net Natural Gas Sales (bcf)	90.8	128.4	$1.41	Final Result ($/Mcf Sales Gas)
Liquids:	Condensate (MMbbl)	1.28			Sales Gas/Raw Gas: 0.920 (Ratio)
	Condensate (Btu 10^{12})	5.93			
	Plant Liquid (Btu 10^{12})	6.47			
	Total NGL's (Btu 10^{12})	12.40	53.5	$0.59	($/Mcf Equiv. Liquids)
	Total Hydrocarbons:		181.9	$2.00	

Note: Totals do not add because of rounding.

*Required working interest revenue is levelized.

Table B-3 — Resource Cost Calculation for Natural Gas Development Project in Indonesia Without Royalty or Tax Payments
(Nominal and real 1989 dollars)

Economic Parameters		Production, Costs	
Equity Ratio	0.60	Daily Prod. Cap. (Raw MMcfd)	285
Nominal Return on Equity (%)	20.0	Nonhydrocarbon Gases (%)	3.0
Equity Term (years)	15	Condensate (bbl/MMcf)	13
		Gas Plant Conversion to Liquids (%)	2.7
Debt Ratio	0.40	Total L&P Fuel Gas Use (%)	2.5
Nominal B.T. Debt Interest (%)	12.0		
Debt Term (years)	10	Platform, Equipment Costs ($MM)	79
		Pipeline, Gas Plant Costs ($MM)	83
Inflation (%)	5.0	Well Costs ($MM)	161
Income Tax Rate	0.00	Total Number of Wells	67
Nominal A.T. Cost of Capital (%)	16.8		
Real A.T. Cost of Capital (%)	11.2	Total Capital Costs, Including Overhead	
Depreciation Period	15	(million 1989$)	517
		Debt	207
Utilization Rate (%)	95.0	Equity	310
Investment Life (years)	15		
		Annual O&M (million 1989$)	10.3
		Annual O&M = 5% of Plant/Pipeline Capital Costs, Plus $125k/Well Offshore, $40k/Well Onshore	
		Value of Crude, Cond. ($/bbl)	27.80
		Value of Plant Liquids ($/MMBtu)	4.31
		Government Royalty (%)	
		Before Payout	0.0
		After Payout	0.0

Table B-3 — Resource Cost Calculation for Natural Gas Development Project In Indonesia Without Royalty or Tax Payments (continued)
(Nominal 1989 dollars)

	Debt						Taxes							
Year	Balance	Payment (C)	Princip.	Interest (E)	Equity Return (F)	Annual O&M (G)	Deprec. (H)	Annual Taxable Income (P-E-G-H)	Tax Losses Incurred	Tax Losses Realized	Losses Carried Over	Adjusted Taxable Income	Income Taxes Paid (N)	Total Costs (C+F+G+N)
1	206.7	36.6	11.8	24.8	66.3	10.3	34.4	18.9	0.0	0.0	0.0	18.9	0.0	113.1
2	194.9	36.6	13.2	23.4	66.3	10.8	34.4	24.2	0.0	0.0	0.0	24.2	0.0	113.6
3	181.7	36.6	14.8	21.8	66.3	11.3	34.4	29.9	0.0	0.0	0.0	29.9	0.0	114.2
4	166.9	36.6	16.5	20.0	66.3	11.9	34.4	35.9	0.0	0.0	0.0	35.9	0.0	114.7
5	150.4	36.6	18.5	18.0	66.3	12.5	34.4	42.4	0.0	0.0	0.0	42.4	0.0	115.3
6	131.8	36.6	20.8	15.8	66.3	13.1	34.4	49.4	0.0	0.0	0.0	49.4	0.0	116.0
7	111.1	36.6	23.2	13.3	66.3	13.7	34.4	56.9	0.0	0.0	0.0	56.9	0.0	116.6
8	87.9	36.6	26.0	10.5	66.3	14.4	34.4	64.9	0.0	0.0	0.0	64.9	0.0	117.3
9	61.8	36.6	29.2	7.4	66.3	15.1	34.4	73.5	0.0	0.0	0.0	73.5	0.0	118.0
10	32.7	36.6	32.7	3.9	66.3	15.9	34.4	82.8	0.0	0.0	0.0	82.8	0.0	118.8
11	(0.0)	0.0	0.0	(0.0)	66.3	16.7	34.4	92.8	0.0	0.0	0.0	92.8	0.0	83.0
12	(0.0)	0.0	0.0	(0.0)	66.3	17.5	34.4	99.1	0.0	0.0	0.0	99.1	0.0	83.8
13	(0.0)	0.0	0.0	(0.0)	66.3	18.4	34.4	105.8	0.0	0.0	0.0	105.8	0.0	84.7
14	(0.0)	0.0	0.0	(0.0)	66.3	19.3	34.4	112.8	0.0	0.0	0.0	112.8	0.0	85.6
15	(0.0)	0.0	0.0	(0.0)	66.3	20.3	34.4	120.2	0.0	0.0	0.0	120.2	0.0	86.6
Total Present Value			207		995	221	517	1,009	0	0		1,009	0	1,581
														597

Table B-3 — Resource Cost Calculation for Natural Gas Development Project in Indonesia Without Royalty or Tax Payments (continued)

(Real 1989 dollars)

Calculated
PV Costs = PV Rev

			Production (bcf/Year)				Required Project Revenues ($ million)			Allocation of W.I. Share ($ million)			
Year	Real Total Costs ($ million)	Real Required Working Int. Revenue ($ million)	Total	Royalty	Working Interest	Resource Cost ($/Mcf Raw)	Total	Royalty	Working Interest	Real Income Taxes	Real O&M	Real Interest	After Inc. Tax Int.& O&M
1	113.1	88.3	98.8	0.0	98.8	$0.89	88.3	0.0	88.3	0.0	10.3	24.8	53.3
2	108.2	88.3	98.8	0.0	98.8	$0.89	88.3	0.0	88.3	0.0	10.3	22.3	55.8
3	103.6	88.3	98.8	0.0	98.8	$0.89	88.3	0.0	88.3	0.0	10.3	19.8	58.3
4	99.1	88.3	98.8	0.0	98.8	$0.89	88.3	0.0	88.3	0.0	10.3	17.3	60.8
5	94.9	88.3	98.8	0.0	98.8	$0.89	88.3	0.0	88.3	0.0	10.3	14.8	63.2
6	90.9	88.3	98.8	0.0	98.8	$0.89	88.3	0.0	88.3	0.0	10.3	12.4	65.7
7	87.0	88.3	98.8	0.0	98.8	$0.89	88.3	0.0	88.3	0.0	10.3	9.9	68.1
8	83.4	88.3	98.8	0.0	98.8	$0.89	88.3	0.0	88.3	0.0	10.3	7.5	70.6
9	79.9	88.3	98.8	0.0	98.8	$0.89	88.3	0.0	88.3	0.0	10.3	5.0	73.1
10	76.6	88.3	98.8	0.0	98.8	$0.89	88.3	0.0	88.3	0.0	10.3	2.5	75.6
11	51.0	88.3	98.8	0.0	98.8	$0.89	88.3	0.0	88.3	0.0	10.3	-0.0	78.1
12	49.0	88.3	98.8	0.0	98.8	$0.89	88.3	0.0	88.3	0.0	10.3	-0.0	78.1
13	47.2	88.3	98.8	0.0	98.8	$0.89	88.3	0.0	88.3	0.0	10.3	-0.0	78.1
14	45.4	88.3	98.8	0.0	98.8	$0.89	88.3	0.0	88.3	0.0	10.3	-0.0	78.1
15	43.7	88.3	98.8	0.0	98.8	$0.89	88.3	0.0	88.3	0.0	10.3	-0.0	78.1
Total	1,173	1,325	1,482	0	1,482		1,325	0	1,325	0	154	136	1,035
Present Value	627	627	701	0	701		627	0	627	0	73	92	462

Table B-3 — Resource Cost Calculation for Natural Gas Development Project In Indonesia Without Royalty or Tax Payments (continued)

(Real 1989 dollars)

Annual Balances		Revenues Volumes	Required Revenues ($ million)	Sales Gas ($/Mcf)	
	Raw Production (bcf)	98.0			
	Non-H.C. Gases (bcf)	3.0			
Gas:	Net H.C. Gases (bcf)	95.8			
	Plant Shrinkage (bcf)	2.6			
	L&P Fuel Use (bcf)	2.4			
	Net Natural Gas Sales (bcf)	90.8	34.8	$0.38	Final Result ($/Mcf Sales Gas)
Liquids:	Condensate (MMbbl)	1.28			Sales Gas/Raw Gas: 0.920 (Ratio)
	Condensate (Btu 10^{12})	5.93			
	Plant Liq. (Btu 10^{12})	6.47			
	Total NGL's (Btu 10^{12})	12.40	53.5	$0.59	($/Mcf Equiv. Liquids)
	Total Hydrocarbons:		88.3	$0.97	

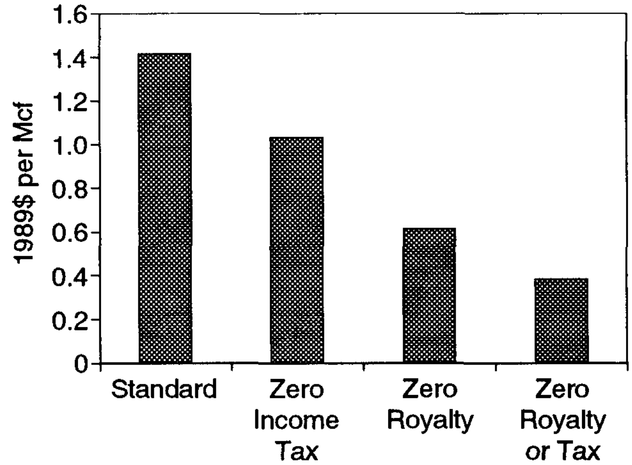
Note: Totals do not add because of rounding.

*Required working interest revenue is levelized.

production previously allocated to the royalty owner is now free to offset capital and operating costs. Income taxes are no longer a cost. Liquids revenue still contributes $0.59 per Mcf. The required revenue per Mcf of sales gas is now only $0.38.

Figure B–1 presents the two calculations discussed above as well as intermediate cases of zero royalty or zero income taxes. In this field example, gas could not be brought to market for any less than $0.38 per Mcf. Zero royalties with a 37.5-percent income tax rate raise costs to $0.61 per Mcf. A 40-percent royalty rate with no income tax brings costs to $1.03 per Mcf. Sales gas costs rise to $1.41 per Mcf under the standard concession arrangement. In the presence of even more onerous terms, such as price controls on a portion of the production, the operator's required revenue per Mcf of sales gas could rise even higher.

Figure B–1 — Typical Field Development Costs Under Various Concession Terms



Note: Costs are for a 2.6-tcf offshore field.

APPENDIX C: ASSOCIATED-DISSOLVED GAS SUPPLIES

INTRODUCTION

The primary purpose of this appendix is to present information on what quantities of associated-dissolved gas are available in selected countries and the degree to which such gas is likely to contribute to projected gas production from these countries. Future production has been estimated by allocating, by country and type of gas, larger scale production estimates made by the Energy Information Administration (EIA). Other outputs from this allocation and projection exercise are estimates of how much of future gas production will come from developed nonassociated gas reserves and what portion, if any, will come from undeveloped, discovered nonassociated gas or as-yet undiscovered nonassociated gas. This will give the reader some idea of how likely some portion of the undeveloped, discovered nonassociated gas represented in the curves shown in this report will be utilized under the EIA forecast.

The second purpose of this appendix is to present example estimates of the resource costs for developing unutilized associated-dissolved gas from oil fields that are now or were recently producing oil. This has been done by estimating the development costs for associated-dissolved gas in a few example fields.

BACKGROUND

Much of the associated-dissolved[1] gas in the countries examined is not currently utilized.

With the exception of North America and Europe, few areas have a well-developed natural gas delivery grid that makes the development of gas more economic. In recent years, and with varying degrees of success, all petroleum-producing countries have expressed a desire to implement greater use of their natural gas resources, including unutilized associated-dissolved gas.

Associated-dissolved gas has been used to supply oil field fuel requirements, for reservoir pressure maintenance projects, and for local fuel needs if convenient. Many countries, most notably Saudi Arabia and Algeria, have created a domestic market for gas that has eliminated much of the waste of associated-dissolved gas that occurred in the past. Saudi Arabia now consumes most of its gas production in its petrochemical industries. Algeria reinjects most of the gas it does not consume or export.

Table C–1 shows the disposition of each country's total gas production in 1987. The last two columns indicate how much of the gas is flared or reinjected. Each country has a unique set of circumstances that influences its use of produced gas. Nigeria, Trinidad, Ecuador, and Argentina still flare a large portion of their gas production because of the lack of gas infrastructure or market.

In some areas with large gas reserves but little market, gas is reinjected for reservoir pressure maintenance after being stripped of liquids. Norway, Algeria, Venezuela, the U.A.E., and Indonesia all reinject a significant amount of their gas production. The gas is produced from both oil reservoirs with dissolved gas and nonassociated gas reservoirs that are cycled for their condensate and NGL production.

Norway and Venezuela reinject a significant amount of associated gas for pressure maintenance in oil reservoirs. Venezuela and Indonesia have many fields that have formed secondary gas caps through pressure depletion of oil reservoirs. The large primary and secondary gas caps that exist in these reservoirs will be available for production after the oil legs of the reservoirs are depleted. Algeria and the U.A.E. reinject gas in both oil

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[1]Natural gas found in reservoirs containing oil is classified as either "associated gas" or "dissolved gas." Associated gas, sometimes called gas cap gas, is located at the top of the reservoir, separated by gravity from the oil. Gas cap gas is typically not produced while the oil is being produced because the pressure from the cap helps push the oil to the borehole, increasing oil recovery. Instead, a gas cap is produced when oil production from the reservoir ends. Dissolved gas, also called solution gas, is dissolved in the oil and must be produced along with the oil. A "secondary gas cap" may form in an oil reservoir as dissolved gas separates from the oil as pressure is reduced during depletion.

Table C-1 — 1987 Total Gas Production Disposition in Selected Countries

	Annual Production Volumes (1987)*						
Country	Gross (bcf)	Flared (bcf)	Reinjected (bcf)	Total Marketed (bcf)	Dry Gas Marketed (bcf)	% of Total Flared	Production: Reinjected (%)
Algeria	3,913	222	1,964	1,727	1,524	5.7	50.2
Argentina	683	95	33	555	527	13.9	4.8
Ecuador	13	11	1	1.4	1.4	84.6	5.4
Indonesia	1,741	131	304	1,307	1,291	7.5	17.5
Malaysia	590	26	—	556	551	4.4	—
Nigeria	583	417	35	131	131	71.5	6.0
Norway	1,247	12	129	1,106	1,071	1.0	10.3
Qatar	227	—	—	227	198	—	—
Saudi Arabia	1,385	71	58	1,257	946	5.1	4.2
Trinidad and Tobago	272	125	—	146	143	46.0	—
U.A.E. (all)	968	82	127	759	667	8.5	13.1
Venezuela	1,280	130	401	749	657	10.2	31.3
Total	12,902	1,322	3,052	8,521	7,707	10.2	23.7

* Source of production data: Energy Information Administration, *International Energy Annual 1988;* Organization of Petroleum Exporting Countries, *OPEC Annual Statistical Bulletin 1988.*

reservoirs and in nonassociated gas cycling projects.

ASSOCIATED-DISSOLVED GAS RESERVE AND PRODUCTION ESTIMATES

This section outlines the methodology employed to estimate nonassociated and associated-dissolved gas reserves by country and to project gas production through the year 2010. Published gas reserve data are available only on a total gas basis (that is, nonassociated plus associated-dissolved). Thus, it was necessary to estimate how much of this represents nonassociated versus associated gas. EIA gas projections are also on a total gas basis, and the projections have been disaggregated by gas type as well (see "Estimates of Future Gas Production," page C–3). The steps taken to allocate future production between the various sources of gas require knowledge of total gas reserves, historical gas production, and a forecast of future crude and total gas production.

Gas reserves in each category have been estimated by treating the undeveloped-nonassociated-gas-reserves estimates developed in the main body of the report as an independent subset of the total gas estimates for each country reported by the *Oil and Gas Journal.* This distinction made it possible to evaluate the demands on associated and developed nonassociated gas reserves separately from the identified undeveloped nonassociated gas. Associated-dissolved gas future production has been estimated with the use of EIA crude oil production projections and analysis of historical production patterns. Nonassociated gas production has been estimated as the difference between the EIA total gas projection and associated gas projection in this report.

"Implications of Production Estimates for Undeveloped Nonassociated Gas" (page C–7) discusses the implications of these production estimates in terms of the amounts of new gas reserves that must be developed over the projected time period.

Estimation of Reserves

Tables C–2 and C–3 summarize the crude oil, total gas, associated-dissolved gas, and nonassociated gas reserve estimates for the phase 1 and 2 countries. Some of the information shown in the tables represents published data while other figures represent estimates.

Crude oil and total gas reserves by country are published annually in the *Oil and Gas Journal* (Oil and Gas Journal 1989). Reserves estimates and annual production statistics for OPEC member countries are published in an annual publication, *OPEC Bulletin* (Organization of Petroleum Exporting Countries 1988). The crude oil reserves values on Table C–2 come from the *Oil and Gas Journal.* The cumulative production values come from data published by the U.S. Geological Survey (Masters et al. 1987), updated to end-of-year 1988 with annual production information from the *OPEC Bulletin* and other sources. This same technique was used to estimate total cumulative gas production.

Table C–2 shows two estimates for total gas (nonassociated plus associated) reserves, one published by the *Oil and Gas Journal* and the other an estimate by EEA. The EEA values are sometimes higher because they include both developed and undeveloped nonassociated reserves, while the *Oil and Gas Journal* includes only some of the undeveloped gas.

The estimates for natural gas reserves are shown in Table C–3 separately for nonassociated gas and associated-dissolved gas. The discovered, undeveloped nonassociated reserves have been estimated in the subject countries on a field-by-field basis. To this has been added the Energy and Environmental Analysis (EEA) estimates for developed nonassociated gas and the sum reported under the heading "Nonassociated Gas Reserves" in Table C–3. Reserve estimates for associated-dissolved gas were first approximated by subtracting EEA's nonassociated reserves estimates from the *Oil and Gas Journal* estimates for total gas reserves. For some countries these preliminary estimates were then adjusted upward to produce gas-to-oil reserve ratios (that is, associated-dissolved reserves divided by crude oil reserves) more consistent with historical production statistics and information available on specific large oil fields in each country.

Estimates of Future Gas Production

The foundation for the gas production forecasts presented here are the EIA projections contained in the 1990 *International Energy Annual* (Energy Information Administration 1988) and in unpublished backup information supplied by EIA. Because the EIA projections are usually made for groups of countries, projected production to individual countries had to be allocated. It was also necessary to convert the EIA projections, which are on a dry marketed basis, to a wet basis including gas that is vented and flared as well as gas that is marketed. The next step was to allocate each country's production between associated-dissolved gas and nonassociated gas. The reader should realize that the resulting forecast by country and type of gas are based on relatively simple allocation rules and are not the result of country-by-country demand analysis.

Total Gas Production Projections to 2010

EIA has projected total (nonassociated plus associated-dissolved) marketed dry gas production for *groups* of countries through 2010. These projections have been disaggregated by country by utilizing 1988 production as the allocation factor. The values for each country were then scaled up to convert from a dry basis to a wet basis (that is, including natural gas liquids removed during processing) and to account for gas that is vented or flared.[2]

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[2]Note that gas production that is reinjected is not counted in this exercise because reinjection does not deplete reserves.

Table C-2 — Crude Oil and Developed Plus Undeveloped Total Gas Reserves by Country (as of January 1, 1989)

	Crude			Developed and Undeveloped Total Gas			OGJ Total Gas
Country	Cum. (BBO)	Reserves (BBO)	Ultimate (BBO)	Cum. (tcf)	Reserves (tcf)	Ultimate (tcf)	Reserves* (tcf)
Abu Dhabi	7	92.2	—	?	183.5	—	183.5
Algeria	8.4	8.4	16.8	20.1	146.7	166.8	104.2
Argentina	4.9	2.2	7.1	11.2	36.6	47.8	26.7
Ecuador	1.4	1.4	2.7	0.7	4.4	5.1	4.0
Indonesia	13.1	8.3	21.3	19.1	88.5	107.6	83.6
Malaysia	2.0	2.9	4.9	5.8	51.7	57.5	51.7
Nigeria	12.4	16.0	28.4	8.3	85.0	93.3	85.0
Norway (north)	0	?	—	0	18.2	18.2	?
Norway (total)	3.0	10.4	13.4	8.1	99.7	107.8	85.5
Qatar	4.1	3.2	7.3	1.0	164.0	165.0	156.7
Saudi Arabia	57.6	255.0	312.6	27.8	278.1	305.9	145.9
Trinidad and Tobago	4.2	0.5	4.8	3.7	13.6	17.3	10.5
U.A.E. (except Abu Dhabi)	?	5.9	—	—	18.0	—	18.0
U.A.E. (incl. Abu Dhabi)	10.9	98.1	109.0	7.6	201.5	209.1	201.5
Venezuela	41.1	58.1	99.2	22.0	108.5	130.6	102.2
Totals	163.1	464.5	627.6	135.4	1,278.3	1,413.7	1,057.5

*As published in the *Oil and Gas Journal*, 12-26-88.
BBO = billion barrels of oil.

Because the amounts of gas that will be vented or flared in the future is very uncertain, two scenarios were created for total gas production. In both scenarios, the amount of venting and flaring declines as a percent of gas production in each country. The "low production" case assumes a more rapid decrease in venting and flaring than does the "high production" case. The results in each scenario for each country in terms of gas production over the 1989 to 2010 period are shown in Table C–4 in the sixth and seventh columns (columns "a" and "b").

Associated-Dissolved Gas Production Projections to 2010

Associated-dissolved gas production estimates were made by first projecting crude oil production through the year 2010 for each country. For non-OPEC countries, EIA provided these crude oil projections. For OPEC countries, EIA has only a total OPEC crude oil production forecast. Future crude production was estimated by using EIA projections of total OPEC productive capacity as the allocation factor among countries (Energy Information

Table C-3 — Developed and Undeveloped Reserves, Cumulative Production, and Ultimate Recovery

Country	Developed & Undeveloped Nonassociated			Associated			Total Gas		
	Cum. (tcf)	Reserves (tcf)	Ultimate (tcf)	Cum. (tcf)	Reserves (tcf)	Ultimate (tcf)	Cum. (tcf)	Reserves (tcf)	Ultimate (tcf)
Abu Dhabi	?	57.1	57.1	?	126.4	?	?	183.5	?
Algeria	10.0	131.54	141.54	10.1	15.1	25.21	20.1	146.7	166.8
Argentina	3.0	30.9	33.9	8.2	5.7	13.88	11.2	36.6	47.8
Ecuador	0.0	0.4	0.4	0.7	4.0	4.72	0.7	4.4	5.1
Indonesia	12.0	81.9	93.9	7.1	6.7	13.73	19.1	88.5	107.6
Malaysia	4.6	25.5	30.1	1.2	26.2	27.36	5.8	51.7	57.5
Nigeria	0.5	29.7	30.2	7.8	55.3	63.03	8.3	85.0	93.3
Norway (north)	0.0	18.2	18.2	0.0	0.0	0.00	0.0	18.2	18.2
Norway (total)	5.5	91.9	97.4	2.6	7.8	10.44	8.1	99.7	107.8
Qatar	?	162.8	162.8	1.0	1.2	2.18	1.0	164.0	165.0
Saudi Arabia	2.00	131.5	133.5	25.8	146.6	172.44	27.8	278.1	305.9
Trinidad and Tobago	0.1	12.9	13.0	3.6	0.7	4.29	3.7	13.6	17.3
U.A.E. (except Abu Dhabi)	2.0	14.5	16.5	?	3.6	?	?	18.0	?
U.A.E. (incl. Abu Dhabi)	2.0	71.6	73.6	5.6	129.9	135.55	7.6	201.5	209.1
Venezuela	0.2	12.1	12.3	21.8	96.4	118.3	22.0	108.5	130.6
Totals	39.9	782.7	822.6	95.5	495.6	591.1	135.4	1,278.3	1,413.7

Administration 1990). The results are shown in Table C–5.

Projections of associated-dissolved production were made by multiplying the crude production by gas-to-oil ratio (GOR) factors. Two projections were made (see Table C–5) using the following assumptions:

(1) Continuation of historical "producing GOR" for each country through the year 2010. Producing GOR is the estimate of the average solution-gas-to-crude-oil production ratio in each country. This value is used to calculate a base gas volume that will be produced over the forecast years solely from crude production operations.

(2) Ramp up over the period 1989–2010 of the "producing GOR" of 50 percent of the difference between the "producing GOR" and the "reserve GOR." The "reserve GOR" is defined as the current associated-dissolved gas reserves divided by current crude oil reserves.

Case number 1 ("Low Estimate," column 6, Table C–5) should be considered a conservative estimate of future associated-dissolved gas production because GOR's generally increase as a function of cumulative crude production and because gas caps tend to be produced or "blown down" in the later stages of an oil field's life. Gas cap production generally has not been a major component of recent historical "producing GOR's."

Table C-4 — Summary of Projected Associated and Nonassociated Wet Gas Production by Country—Selected Countries

Country	Developed Associated Reserves (tcf)	Developed NAG Reserves (tcf)	Undeveloped NAG Reserves (tcf)	Developed and Undeveloped NAG Reserves (tcf)	EIA Total Gas Projections (Wet, M,V,&F) (1989–2010)* (tcf) (a)	(b)	Associated Gas Projections (Wet, M,V,&F) (1989–2010)** (tcf) (c)	(d)	Wet Marketed Nonassociated Gas Projections (1989–2010)*** (tcf) a – d	b – c
Algeria	15.1	97.3	34.3	131.6	54.0	55.6	11.3	12.8	41.2	44.3
Argentina	5.7	13.1	17.8	30.9	26.8	27.8	5.1	5.7	21.1	22.7
Ecuador	4.0	0.0	0.4	0.4	1.5	2.5	1.1	1.3	0.2	1.4
Indonesia	6.7	21.4	60.4	81.8	42.4	43.0	6.2	7.0	35.3	36.7
Malaysia	25.7	4.0	21.5	25.5	25.0	25.0	2.4	11.0	14.0	22.6
Nigeria	54.7	0.8	29.0	29.8	15.6	22.2	7.4	16.0	-0.4	14.8
Norway	7.8	2.3	61.6	63.9	28.4	28.4	13.6	19.0	9.4	14.7
Qatar	1.2	2.0	160.8	162.8	7.0	7.0	0.8	0.9	6.1	6.2
Saudi Arabia	146.6	10.0	121.5	131.5	44.9	45.5	24.8	26.8	18.2	20.6
Trinidad and Tobago	0.7	1.0	11.9	12.9	7.8	9.1	0.5	0.6	7.2	8.5
U.A.E.	128.5	14.9	56.7	71.6	24.4	25.0	9.7	13.8	10.6	15.4
Venezuela	96.4	2.0	10.1	12.1	24.0	24.9	12.1	19.4	4.6	12.8
Totals	493.1	168.8	586.0	754.8	301.7	315.8	95.1	134.2	167.5	220.7

*Allocation based upon actual 1988 total gas production by country. Two scenarios were developed to estimate marketed, vented, and flared wet gas from dry marketed gas (see text).
**Low and high EEA associated gas projections based on different GOR assumptions (see text).
***Nonassociated projections represent difference between total gas and associated gas projections (see subheadings).
M=marketed F=flared V=vented NAG=nonassociated gas

For example, the associated gas production projections for Malaysia in Table C–4 range from 2.4 to 10.9 tcf over the forecast period. The lower estimate is based on a Case number 1 historical "producing GOR" of 580. The higher estimate utilizes (incrementally) the Case number 2 overall "reserve GOR" of 8,800. The much higher "reserve GOR" includes the possibility of significant increases in solution and associated gas production as gassier fields are brought on stream and gas caps are blown down in older fields.

Nonassociated Production Projections to 2010

The two nonassociated production projections for each country represent the differences between an EIA-based total gas projection and an associated-dissolved projection. The low nonassociated gas projection is determined by subtracting the higher associated-dissolved gas projection (the one with higher GOR's) from the low total gas projection (that is, the one based on a low amount of venting

Table C–5 — Crude Oil and Associated Gas Projections by Country—Selected Countries (1989–2010)

	Annual Volumes		Projected Cumulative Production, 1989–2010			
Country	1988 Crude Production (BBO)	Percent of 1988 Crude Production	Projected Crude Production (BBO)	Percent of Projected Crude Production	Low Estimate of Associated Production (tcf)	High Estimate of Associated Production (tcf)
Algeria	0.4	6.7	9.4	5.9	11.3	12.8
Argentina	0.2	2.8	3.0	1.9	5.1	5.7
Ecuador	0.1	1.9	2.3	1.4	1.1	1.3
Indonesia	0.5	8.6	11.5	7.3	6.2	7.0
Malaysia	0.2	3.5	4.2	2.6	2.4	11.0
Nigeria	0.5	9.3	11.9	7.5	7.4	16.0
Norway	0.4	7.4	15.5	9.8	13.6	19.0
Qatar	0.1	2.3	3.1	2.0	0.8	0.9
Saudi Arabia	1.9	33.9	55.5	35.0	24.8	26.8
Trinidad and Tobago	0.1	1.1	0.6	0.4	0.5	0.6
U.A.E.	0.6	10.4	18.7	11.8	9.7	13.8
Venezuela	0.7	12.3	22.8	14.4	12.1	19.4
Total	5.7	100.0	158.4	100.0	95.1	134.2

BBO = billion barrels of oil.

and flaring). The high nonassociated gas projection is determined by subtracting the lower associated gas projection (low GOR's) from the high total gas projection (higher percent of venting and flaring). The resulting forecasts are shown in Table C–4 in the last two columns.

Implications of Production Estimates for Undeveloped Nonassociated Gas

As shown in Table C–5, total crude oil production for the subject countries is expected to be 158.44 billion barrels over the period 1989–2010, and associated-dissolved gas production is expected to range from 95.07 tcf to 134.24 tcf. As is shown in Table C–4, given this range of associated-dissolved gas production and the expected range of total gas production (302 to 316 tcf), nonassociated gas production is expected to range from 167 tcf to 221 tcf. This compares with an estimate for developed nonassociated gas reserves of 168.80 tcf as of 1989 (column 2 of Table C–4) and an estimate of 586 tcf for undeveloped nonassociated gas reserves (column 3 of Table C–4).

Table C–6 shows the gas production forecast for several individual years. For the year 2010, nonassociated gas production is expected to range from 7.8 tcf to 11.3 tcf per year. To support the level of nonassociated gas production, about 156 to 226 tcf of developed reserves must be on the books during that year.[3] This means that total requirements for

[3]This is based on an assumed average reserve-to-production ratio of approximately 20.

Table C-6 — Production Projections—Phase 1 and 2 Countries

Country	Product	1988	1995	2000	2005	2010	Cumulative 1989–2010
		Projected Annual Production Values					
Algeria	Annual crude (BBO)	0.380	0.414	0.413	0.433	0.458	9.406
	Low assoc. gas (tcf)	0.456	0.497	0.496	0.520	0.550	11.287
	High assoc. gas (tcf)	0.456	0.536	0.563	0.620	0.687	12.770
	Low total gas (tcf)	2.034	2.316	2.438	2.645	2.829	53.981
	High total gas (tcf)	2.042	2.396	2.582	2.723	2.829	55.582
	Low nonassoc. (tcf)	1.578	1.780	1.875	2.025	2.143	41.211
	High nonassoc. (tcf)	1.586	1.899	2.086	2.203	2.280	44.295
Argentina	Annual crude (BBO)	0.164	0.155	0.136	0.115	0.096	3.016
	Low assoc. gas (tcf)	0.277	0.263	0.229	0.195	0.163	5.096
	High assoc. gas (tcf)	0.277	0.284	0.261	0.232	0.203	5.694
	Low total gas (tcf)	0.740	1.028	1.193	1.439	1.690	26.791
	High total gas (tcf)	0.743	1.072	1.280	1.492	1.690	27.757
	Low nonassoc. (tcf)	0.463	0.745	0.932	1.207	1.487	21.097
	High nonassoc. (tcf)	0.466	0.809	1.050	1.297	1.528	22.660
Ecuador	Annual crude (BBO)	0.113	0.105	0.137	0.086	0.081	2.275
	Low assoc. gas (tcf)	0.057	0.053	0.069	0.043	0.000	1.097
	High assoc. gas (tcf)	0.057	0.057	0.078	0.051	0.050	1.275
	Low total gas (tcf)	0.163	0.098	0.028	0.031	0.033	1.497
	High total gas (tcf)	0.168	0.148	0.119	0.080	0.033	2.505
	Low nonassoc. (tcf) *	0.107	0.041	0.000	0.000	0.000	0.222
	High nonassoc. (tcf)	0.112	0.095	0.050	0.037	0.033	1.408
Indonesia	Annual crude (BBO)	0.485	0.518	0.510	0.539	0.572	11.490
	Low assoc. gas (tcf)	0.262	0.280	0.275	0.291	0.309	6.205
	High assoc. gas (tcf)	0.262	0.302	0.313	0.347	0.386	7.029
	Low total gas (tcf)	1.522	1.794	1.940	2.105	2.251	42.351
	High total gas (tcf)	1.525	1.824	1.993	2.133	2.251	42.946
	Low nonassoc. (tcf)	1.260	1.492	1.627	1.758	1.865	35.322
	High nonassoc. (tcf)	1.263	1.544	1.718	1.842	1.942	36.741
Malaysia	Annual crude (BBO)	0.197	0.208	0.191	0.175	0.156	4.187
	Low assoc. gas (tcf)	0.115	0.121	0.111	0.102	0.091	2.433
	High assoc. gas (tcf)	0.115	0.393	0.539	0.658	0.734	10.978
	Low total gas (tcf)	0.615	0.927	1.145	1.382	1.623	25.012
	High total gas (tcf)	0.614	0.926	1.144	1.381	1.623	24.996
	Low nonassoc. (tcf)	0.500	0.534	0.606	0.724	0.888	14.034
	High nonassoc. (tcf)	0.499	0.805	1.033	1.279	1.532	22.563
Nigeria	Annual crude (BBO)	0.529	0.555	0.509	0.531	0.560	11.876
	Low assoc. gas (tcf)	0.331	0.347	0.319	0.332	0.351	7.434
	High assoc. gas (tcf)	0.331	0.594	0.706	0.905	1.132	16.022
	Low total gas (tcf)	1.271	0.883	0.453	0.492	0.526	15.600
	High total gas (tcf)	1.305	1.213	1.047	0.814	0.526	22.229
	Low nonassoc. (tcf) *	0.940	0.290	0.000	0.000	0.000	0.000
	High nonassoc. (tcf)	0.974	0.866	0.728	0.481	0.175	14.795
Norway (all)	Annual crude (BBO)	0.417	0.719	0.747	0.729	0.692	15.484
	Low assoc. gas (tcf)	0.368	0.633	0.658	0.642	0.609	13.642
	High assoc. gas (tcf)	0.368	0.782	0.923	1.008	1.058	19.006
	Low total gas (tcf)	1.134	1.329	1.326	1.313	1.296	28.368
	High total gas (tcf)	1.134	1.329	1.326	1.313	1.296	28.368
	Low nonassoc. (tcf)	0.766	0.547	0.403	0.305	0.238	9.361
	High nonassoc. (tcf)	0.766	0.696	0.668	0.671	0.687	14.726

Table C–6 — Production Projections—Phase 1 and 2 Countries (continued)

Country	Product	Projected Annual Production Values 1988	1995	2000	2005	2010	Cumulative 1989–2010
Qatar	Annual crude (BBO)	0.127	0.131	0.137	0.161	0.176	3.143
	Low assoc. gas (tcf)	0.031	0.032	0.033	0.039	0.043	0.767
	High assoc. gas (tcf)	0.031	0.035	0.038	0.047	0.054	0.880
	Low total gas (tcf)	0.238	0.291	0.323	0.350	0.375	6.955
	High total gas (tcf)	0.238	0.291	0.322	0.350	0.375	6.948
	Low nonassoc. (tcf)	0.207	0.256	0.285	0.303	0.320	6.075
	High nonassoc. (tcf)	0.207	0.259	0.289	0.311	0.332	6.181
Saudi Arabia	Annual crude (BBO)	1.930	2.472	2.397	2.755	2.970	55.446
	Low assoc. gas (tcf)	0.865	1.107	1.074	1.234	1.331	24.840
	High assoc. gas (tcf)	0.865	1.158	1.157	1.370	1.520	26.789
	Low total gas (tcf)	1.604	1.900	2.063	2.238	2.393	44.938
	High total gas (tcf)	1.607	1.926	2.110	2.263	2.393	45.465
	Low nonassoc. (tcf)	0.739	0.742	0.906	0.868	0.873	18.149
	High nonassoc. (tcf)	0.742	0.819	1.036	1.029	1.063	20.625
Trinidad and Tobago	Annual crude (BBO)	0.055	0.034	0.024	0.018	0.014	0.622
	Low assoc. gas (tcf)	0.047	0.029	0.020	0.015	0.012	0.530
	High assoc. gas (tcf)	0.047	0.031	0.023	0.018	0.015	0.583
	Low total gas (tcf)	0.299	0.335	0.313	0.378	0.443	7.800
	High total gas (tcf)	0.304	0.393	0.428	0.447	0.443	9.072
	Low nonassoc. (tcf)	0.252	0.304	0.290	0.360	0.429	7.217
	High nonassoc. (tcf)	0.257	0.364	0.407	0.432	0.432	8.542
U.A.E. (all)	Annual crude (BBO)	0.586	0.787	0.834	0.937	1.014	18.728
	Low assoc. gas (tcf)	0.302	0.405	0.430	0.483	0.522	9.645
	High assoc. gas (tcf)	0.302	0.505	0.611	0.771	0.926	13.782
	Low total gas (tcf)	0.908	1.044	1.108	1.202	1.285	24.425
	High total gas (tcf)	0.911	1.075	1.163	1.232	1.285	25.039
	Low nonassoc. (tcf)	0.606	0.539	0.497	0.431	0.359	10.642
	High nonassoc. (tcf)	0.609	0.669	0.733	0.749	0.763	15.394
Venezuela	Annual crude (BBO)	0.695	0.919	0.995	1.200	1.300	22.745
	Low assoc. gas (tcf)	0.369	0.488	0.528	0.637	0.690	12.078
	High assoc. gas (tcf)	0.369	0.655	0.838	1.166	1.431	19.431
	Low total gas (tcf)	0.922	1.035	1.076	1.168	1.249	23.977
	High total gas (tcf)	0.926	1.078	1.155	1.210	1.249	24.856
	Low nonassoc. (tcf) *	0.553	0.380	0.239	0.002	0.000	4.547
	High nonassoc. (tcf)	0.557	0.590	0.627	0.573	0.558	12.778
Totals	Annual crude (BBO)	5.678	7.017	7.029	7.679	8.089	158.418
	Low assoc. gas (tcf)	3.478	4.255	4.242	4.533	4.670	95.053
	High assoc. gas (tcf)	3.478	5.330	6.048	7.192	8.196	134.239
	Low total gas (tcf)	11.450	12.980	13.406	14.741	15.994	301.696
	High total gas (tcf)	11.517	13.669	14.668	15.437	15.994	315.763
	Low nonassoc. (tcf)	7.972	7.650	7.358	7.548	7.798	167.457
	High nonassoc. (tcf)	8.039	9.414	10.426	10.904	11.324	220.710

* The projection methodology used resulted in some negative nonassociated production values. Zeros have been inserted where this occurred.

nonassociated gas (cumulative production plus reserves that must be developed) will total 323 to 447 tcf through 2010. Given proved developed reserves of 168.8 tcf in 1989, this means that 154 to 278 tcf of nonassociated gas must be developed in the subject countries between now and the year 2010 to sustain the level of production consistent with the EIA forecast. The calculations behind this conclusion are recapped below:

Nonassociated gas production from 1989–2010	167–221
Plus reserves needed in 2010 to sustain production	156–226
Equals total nonassociated requirements	323–447
Less 1989 developed reserves	169
Equals nonassociated reserves that must be developed by 2010	154–278

This amount of newly developed nonassociated gas reserves could either come from the 586 tcf of discovered, undeveloped nonassociated gas identified in these countries in this study or from newly discovered nonassociated gas that may be found by the year 2010. If it were to all come from currently discovered, undeveloped nonassociated gas, 26 to 47 percent of available quantities would be used. This indicates clearly that there will likely be significant demands on the discovered, undeveloped nonassociated gas in the subject countries even in the absence of any U.S. alternative-fuels program that would create a new demand for the gas.

COST ESTIMATES FOR ASSOCIATED–DISSOLVED GAS

This section presents some examples of the costs that would be incurred to gather and bring to market the solution gas that is produced with oil in currently developed oil fields. Some additional estimates of the cost of producing associated gas from the blowdown of an oil reservoir gas cap are also presented.

Solution gas that is not otherwise utilized is typically flared or reinjected. As was shown in Table C–1, Nigeria, Trinidad, Ecuador, and Argentina still flare a large portion of their gas production because of the lack of gas infrastructure or market. Norway, Algeria, Venezuela, the U.A.E., and Indonesia all reinject a significant amount of their gas production. No new wells are required to produce flared or reinjected gas, but a substantial investment in gathering and processing facilities may be required. To bring presently flared gas to market will require gas gathering lines, compression, a gas processing plant, and a gas sales pipeline. Reinjected gas will typically require less of an investment in gathering and compression, but may still require substantial investment in gas processing and transportation.

Venezuela and Indonesia have many fields that have formed secondary gas caps through pressure depletion of oil reservoirs. The large primary and secondary gas caps that exist in these reservoirs will be available for production after the oil legs of the reservoirs are depleted. In fields with significant gas reinjection, the majority of the infrastructure for gas gathering and marketing is in place. However, gas cap blowdown will require that some new wells be drilled to the gas cap, probably some expansion of gas handling facilities, and a gas sales pipeline.

Key Cost Parameters

The unit cost (dollars per Mcf) for associated-dissolved gas is determined in large part by individual well flowrates. Solution gas production is dependent on both a well's oil flowrate and solution GOR. Older wells produce at low rates and consequently have high unit gathering and compression costs. Newer fields have higher flowrates from each well and, hence, typically have lower per unit costs for solution gas.

Gas cap blowdown investment costs are relatively low. The most significant investment is for a gas processing plant and sales pipeline. Individual well flowrates should be relatively high. Compression requirements should be less than in a low-pressure solution-gas-gathering system and could be virtually zero if a field has gas-injection equipment in place.

General Assumptions for Dissolved (Solution) Gas

The gas that is dissolved in the liquid oil in the reservoir will break out of solution as a gas at surface conditions. The proportion of gas in solution is a function of the geology, hydrocarbon source, and reservoir pressure. Solution GOR ranges anywhere from less than 100 standard cubic feet (scf) per barrel (dead oil), to more than 100,000 scf per barrel. Reservoirs that produce liquids at GOR's more than 10,000 scf per barrel are generally classified as gas.

Some amount of produced gas is required to power the equipment used to operate an oil field, and some degree of gas handling capability must be in place in order to produce and stabilize the oil. Estimates of the additional investment required to gather, process, and bring to market excess solution gas assumes that the majority of the associated gas is flared and that no processing or gathering facilities beyond primary separation exist for the gas.

Gas plant liquids recovery from solution gas is assumed to be in the range of 35 to 40 barrels per MMcf (about 4.5 percent shrinkage). The revenue received from the plant liquids is assumed to be equivalent to 90 percent of the value of crude in the year 2000 ($27.80 per barrel in 1989 dollars). No additional condensate production is assumed from the solution gas.

The following general assumptions have been made:

- No new wells are required.
- New gathering lines and dehydration required for each well are linked into the gas-gathering system.
- New compression facilities are required.
- New gas processing plant is required.
- New gas sales pipeline is required.
- No incremental well operating cost is incurred.

Consistent with the nonassociated gas field development resource cost calculations utilized in the main body of this report, the economic calculations assume a constant flowrate for 15 years, with a total field R/P of 25.

No increase in the number of oil wells dedicated to the project is assumed to be necessary during the 15-year life of the project. This assumption reflects the low decline rate typical of mature oil fields and the probability that producing GOR's will be increasing as the oil reservoirs deplete.

Gathering line costs are based on the assumption that the oil wells require about 0.3 miles of new gas gathering line for each well. Total gathering line, metering, and dehydration cost for the gas is assumed to be about $17,000 per well. Offshore oil wells were assumed to require a nominal $5,000 investment to hook up with a gas sales system. Compression horsepower is based on the assumption that inlet pressure is less than 50 pounds per square inch (psi) in older solution gas fields, and the gas must be raised to 750 psi for inlet to a gas-processing plant. In newer, or waterflooded, reservoirs, compression requirements were based on a 100-psi inlet. No additional operating costs for operating the wells have been added to the cost calculations, but an annual operating cost equivalent to 5 percent of the gas plant and pipeline capital costs has been included. The gas processing plant is assumed to be a totally new facility, as is the gas sales pipeline from the field.

General Assumptions for Blowdown of Naturally Occurring Primary or Secondary Gas Caps

The number of new wells and amount of new equipment required to produce gas from an oil reservoir gas cap is dependent on a field's specific geology and development history. A naturally occurring primary gas cap or a secondary gas cap created by pressure depletion of an undersaturated oil reservoir will require new wells for exploitation. Assuming no prior investment in gas facilities has been made, new gas processing facilities and a pipeline will also be required. Gas plant liquids are assumed to be about 35 to 40 barrels per MMcf (about 4.5 percent shrinkage). Compression from about 100 psi to 750 psi is assumed to be required. Initial flowrates of completions in a gas cap are assumed to be relatively high and similar to gas fields in the area. Individual wells decline at a rate similar to gas field completions.

In the estimates of the cost of blowing down a naturally occurring primary or secondary gas cap, the following assumptions have been made:

- Sixty percent of required wells are new or replacement wells.
- Twenty percent of required wells are recompletions in existing boreholes (at one-third the cost of a new well).
- New gathering lines and dehydration are required for each well.
- A new gas processing plant is required.
- New gas handling facilities and compression are required.
- New gas pipeline is required.
- Additional operating costs for blowdown wells are incurred.

General Assumptions for Gas Caps Formed by Injected Gas

A gas cap that has been fed by injection of gas will already be in contact with the injection wells, and fewer new wells will be required for production. Presumably, some compression and gas processing facilities will already be in place, and the greatest expense required to bring the gas to market will be a new sales pipeline. Gas plant liquids are assumed to be somewhat lower than solution gas or naturally occurring reservoir gas caps.

The following assumptions have been made for a gas cap formed by gas injection:

- Twenty percent of required wells are new or replacement wells.
- Twenty percent of required wells are recompletions (at one-third the cost of a new well).
- New gathering lines and dehydration are required for each new well.
- Some additional investment in gas plant expansion is required.
- No new gas facilities or compression are required.
- New gas pipeline is required.
- Additional operating costs for blowdown wells are incurred.

Although it has been assumed that new wells are required to drain the gas cap, the gas flowrates are assumed to be fairly high because the injected gas that is produced back should be dry. A gas cap formed by reinjection is assumed to be at a fairly high pressure and should not require compression in the field. Recompletions are assumed to cost about one-third that of a new well.

Again, the economic calculations assume a constant flowrate for 15 years, with a total field flowrate equivalent to an R/P of 25. Individual wells are assumed to decline at a typical decline rate for gas wells in the area. New wells are brought on as required to maintain a constant flowrate for 15 years.

Field Examples

Example Cost Calculation—Venezuela

Two associated gas cost estimates were made for Venezuela. They are based loosely on the La Paz field in northwest Venezuela, a large oil field that has a solution gas primary drive. The field is still producing oil with associated gas production at about 5.9 MMcfd (GOR approximately 600 scf per barrels). Large secondary gas caps have formed in the oil reservoirs, but no gas injection has taken place.

Two example cost calculations have been made. Table C–7 illustrates the production parameters and costs associated with marketing the presently produced solution gas. The field produces 5.9 MMcfd of excess solution gas from about 66 wells (89 Mcfd per well). In the example cost calculation, existing oil wells are tied into a gas gathering system and the gas is compressed, processed, and transported to a port 18 miles distant. The cost of marketing the gas is driven by the gas plant and pipeline investment. The solution sales gas is estimated to cost $3.81 per Mcf to market in this example. If the field is only 9 miles from a gas sales trunkline, costs drop to $2.32 per Mcf.

Table C–8 illustrates the example of gas produced from the secondary gas caps formed in the field. Although the reservoir is at a

Table C-7 — Venezuela La Paz Field Solution Gas
(1988 million dollars)

Development for Processing Plant Assumed
Calculations Based on 15-Year Plant Life and Required
Inlet of 6 MMcfd for 15 Years

TD 6,000′
0.0% H_2S, 1.0% CO_2, 0 bbl/MMcf Condensate
4.5% Gas Plant Liquid Shrinkage

18-Mile Onshore Pipeline to Concepcion

Input:

Total Reserves per Plant (bcf)	54
Initial Well Production (MMcfd)	0.09
Years Flat Production per Well	1
Annual Decline Rate per Well	0.000
R/P, Total Project	25
Discount Rate	0.10
La Paz Solution Gas (bcf)	54

No. of Process Plants	Total No. Prod. Wells	Developed Reserves (bcf)	Gas Prod. Equip.	PV of Well Aband.	Gas P/L	Oil P/L	Total Exc. Wells	PV of New Wells and Equip.	Gas Plant	Total	Total Incl. Overhead
1	66 Existing Wells	54 Solution Gas	1.4 Compression	0	9 Land	0 Land	10	1.1	2.0	13.6	20.4

One processing plant at 6 MMcfd

Wells at 1988 cost, $M 0.017 per well (gathering, metering, dehydration)

Well life of about 10 years.
Gas plant costs based on 20 MMcfd train size; includes NGL plant and amine plant if required.
Overhead 20%, contingency 10%, owner's cost 20% added to total development cost.

Location equipment cost multiplier:	1.20
Location platform cost multiplier:	1.60
Location well cost multiplier:	1.00
Pipeline cost multiplier:	1.00

Table C-8 — Venezuela La Paz Field Gas Cap Blowdown
(1988 million dollars)

Development for Processing Plant Assumed
Calculations Based on 15-Year Plant Life and Required
Inlet of 241 MMcfd for 15 Years

TD 6,000′
0.0% H_2S, 1.0% CO_2, 1 bbl/MMcf Condensate
4.5% Gas Plant Liquid Shrinkage

18-Mile Onshore Pipeline to Concepcion

Input:	
Total Reserves per Plant (bcf)	2,200
Initial Well Production (MMcfd)	10
Years Flat Production per Well	1
Annual Decline Rate per Well	0.140
R/P, Total Project	25
Discount Rate	0.10
La Paz Gas Cap Gas (bcf)	2,200

No. of Process Plants	Total No. Prod. Wells	Developed Reserves (bcf)	Gas Prod. Equip.	PV of Well Aband.	Gas P/L	Oil P/L	Total Exc. D & C	PV of New Wells D & C	Gas Plant	Total	Total Incl. Overhead
	Total:		Separation					New Wells			
1	72	2,200	7.7	6.7	8.6 Land	0 Land	42	10.4	20.7	74.1	111
	44 New Wells		18.6					1.2 Recompletes			
	14 Recompletes		Compression					0.3 Reworks			
	14 Reworks										

One processing plant at 241 MMcfd

Wells at 1988 cost, $M 0.33 per new well, $0.017 M gas gathering, dehydration per existing well
Number of wells assumes additional wells drilled as required to sustain capacity for 15 years.

Well life of about 10 years.
Gas plant costs based on 20 MMcfd train size; includes NGL plant and amine plant if required.
Overhead 20%, contingency 10%, owner's cost 20% added to total development cost.

Location equipment cost multiplier:	1.20
Location platform cost multiplier:	1.60
Location well cost multiplier:	1.00
Pipeline cost multiplier:	1.00

relatively low pressure, production from the gas cap should be at a good rate because of the dry gas production stream. Sixty percent of the producing wells were assumed to be new, because no gas injection wells were completed in the field. Total gas reserves are estimated to be about 2.2 tcf. At an initial R/P of 25, production from the gas caps should be about 241 MMcfd. Seventy-two wells are required, 44 of which are new. Although the gas plant investment is high in this example, the very high gas flowrate yields a low-cost source of gas. The gas cap blowdown operations are estimated to cost $0.59 per Mcf before liquids extraction. After liquids revenue is considered, the required sales gas revenue is only $0.05 per Mcf.

Example Cost Calculation—Trinidad and Tobago

Two associated gas cost estimates were made for Trinidad: an older onshore field and an offshore field. They are based loosely on the Moruga West (onshore) and the Teak (offshore) field. The onshore field produces about 3.9 MMcfd from about 120 wells at a GOR of 700. Gas production per well is only about 32 Mcfd because of the low flowrates of the oil wells. The offshore field is also assumed to produce oil with a GOR of 700, but each well produces over 580 barrels of oil per day, yielding about 0.4 MMcfd of gas. Total offshore field gas production is about 21.6 MMcfd.

Table C–9 illustrates the onshore field production parameters and costs associated with marketing the presently produced solution gas. In the example cost calculation, existing oil wells are tied into a gas gathering system and the gas is compressed, processed, and transported to a port 10 miles distant. The cost of marketing the gas is driven by the gas plant and pipeline investment. The solution sales gas is estimated to cost $3.69 per Mcf to market in this example. If the field is only 5 miles from a gas sales trunkline, costs drop to $2.44 per Mcf.

Table C–10 illustrates the example of gas produced from the offshore field. Although the gas plant and pipeline investments are higher in this example, the very high gas flowrate yields a low-cost source of gas. The offshore solution gas marketing operations are estimated to cost $1.20 per Mcf.

Cost Summary

A sampling of estimated associated-dissolved gas development costs from several countries is presented in Figure C–1 and Table C–11. In all cases, a new gas processing plant and a new gas sales pipeline were included in the investment. Compression investment was included in all examples except injected gas cap blowdowns. Some new wells and separation facilities were required in all gas cap blowdown examples. Gathering line and metering equipment cost were added to all examples. Solution gas examples did not include any new wells.

The lowest cost sources of associated gas are generally gas cap blowdowns and solution gas from younger, high-rate oil fields. For example, the estimated cost of gathering solution gas from fields in the U.A.E. (examples B and C in Figure C–1) is in the same range as the cost of blowing down a large gas cap in Venezuela (example A). Both of these gas sources produce at relatively high volumes from individual wells.

Solution gas from mature oil fields is relatively expensive to gather and treat if no gas sales processing or transportation infrastructure is in place. For example, the most expensive gas shown in Figure C–1 is the solution gas from onshore fields in Trinidad and Venezuela (examples P and Q). Although these are old, fully developed oil fields, if entirely new gas processing facilities and a sales pipeline must be constructed, the unit cost of gas development becomes very high. These same fields recalculated with only half the investment in a gas sales pipeline or with the gas plant investment eliminated yield a development cost about a third lower (examples K and L).

The development cost of associated gas in the various areas studied may range from a few cents per Mcf to nearly $4.00 per Mcf depending on well flowrates and the gas infrastructure in place. About one-half of the gas in the sample fields had costs below $1.00 per Mcf. As a natural gas infrastructure is built in these countries, the increasing availability of nearby gas pipelines and processing facilities will tend to reduce these costs.

Table C-9 — Trinidad and Tobago Typical Land Field Solution Gas Development
(1988 million dollars)

Development for Processing Plant Assumed
Calculations Based on 15-Year Plant Life and Required
Inlet of 4 MMcfd for 15 Years

TD 4,000′
0.0% H_2S, 1.0% CO_2, 0 bbl/MMcf Condensate
4.5% Gas Plant Liquid Shrinkage

10-Mile Onshore Pipeline to Moruga

Input:	
Total Reserves per Plant (bcf)	36
Initial Well Production (MMcfd)	0.04
Years Flat Production/Well	1
Annual Decline Rate per Well	0.000
R/P, Total Project	25
Discount Rate	0.10
Solution Gas (bcf)	36

No. of Process Plants	Total No. Prod. Wells	Developed Reserves (bcf)	Gas Prod. Equip.	PV of Well Aband.	Gas P/L	Oil P/L	Total Exc. Wells	PV of New Wells and Equip.	Gas Plant	Total	Total Incl. Overhead
1	99 Existing Wells	36 Solution Gas	0.8 Compression	0	5 Land	0 Land	5.8	1.7	1.3	8.8	13.2

One processing plant at 4 MMcfd

Wells at 1988 cost, $M 0.017 per new well (gathering, metering, dehydration)

Well life of about 10 years.
Gas plant costs based on 20 MMcfd train size; includes NGL plant and amine plant if required.
Overhead 20%, contingency 10%, owner's cost 20% added to total development cost.

Location equipment cost multiplier:	1.00
Location platform cost multiplier:	1.60
Location well cost multiplier:	1.00
Pipeline cost multiplier:	1.00

Table C-10 — Trinidad and Tobago Typical Offshore Field Solution Gas Development
(1988 million dollars)

Field Development for Processing Plant Assumed
Calculations Based on 15-Year Plant Life and Required
Inlet of 22 MMcfd for 15 Years

TD 10,000′
0.0% H_2S, 1.0% CO_2 0 bbl/MMcf Condensate
185-Foot Water Depth 4.5% Gas Plant Liquid Shrinkage
23 Miles Offshore Pipeline
5 Miles Onshore Pipeline

Input:	
Total Project Reserves (bcf)	197
Initial Well Production (MMcfd)	0.45
Years Flat Production per Well	1
Annual Decline Rate per Well	0.000
R/P, Total Project	25
Discount Rate	0.10
Solution Gas (bcf)	197

No. of Process Plants	No. of Prod. Wells	No. Platf.	No. Slots/ Platf.	Developed Reserves (bcf)	Cost* Per Platf.	Total Platf. Costs	Platf. Rig Mobil.	Gas Prod. Equip.	PV of Well Aband.	Gas P/L	Oil P/L	Total Exc. Wells	PV of New Wells and Equip.	Gas Plant	Total	Total Incl. Overhead
1	48 Existing Wells	2.0	24	197	0	0	0	4.6 Compression	0	9 Off 3 Land	0 Off 0 Land	15.9	0.2	3.8	20	30

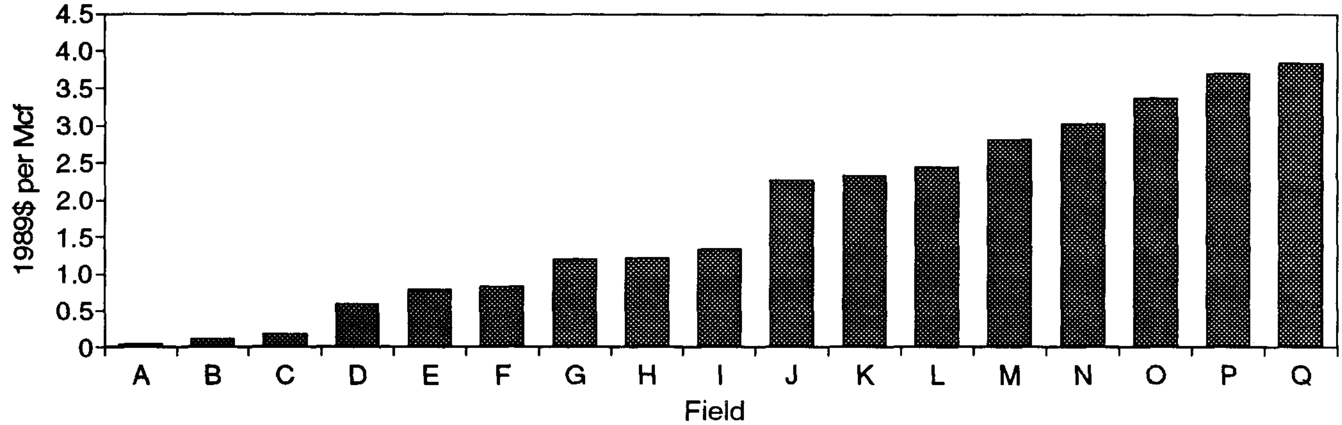
One processing plant at 22 MMcfd

Wells at 1988 cost, $0.005 $M per well (gathering, metering, dehydration)

Gas plant costs based on 20 MMcfd train size; includes NGL plant and amine plant if required.
Well life of about 12 years.
Overhead 20%, contingency 10%, owner's cost 20% added to total development cost.

Location equipment cost multiplier:	1.00
Location platform cost multiplier:	1.60
Location well cost multiplier:	1.00
Pipeline cost multiplier:	1.00

Figure C-1 — Associated Gas Development Costs in Selected Countries



Note: See Table C-11 for location of field.

Table C-11 — Summary of Resource Costs for Associated Gas

Field	Raw Reserves (bcf)	Daily Raw Prod. (MMcfd)	Non-HC Gases (%)	Cond. (bbl/MMcf)	Plant Shrink (%)	Net Gas (bcf/Yr)	Sales Gas ($/Mcf)
A La Paz Gas Cap Blowdown (Venezuela Onshore)	2,200	241	1.0	1	4.5	76.9	0.05
B Onshore Solution Gas Field (U.A.E.)	1,113	122	1.0	0	4.5	38.9	0.11
C Offshore Solution Gas Field (U.A.E.)	1,871	205	1.0	0	4.5	65.4	0.18
D Onshore Solution Gas Field (Algeria)	1,597	175	1.0	0	4.5	55.9	0.59
E Offshore Solution Gas Field (Indonesia)	206	23	1.0	0	4.5	7.3	0.79
F Obagi Gas Cap Blowdown (Nigeria Onshore)	1,282	141	1.0	10	4.5	44.9	0.84
G Offshore Solution Gas Field (Trinidad)	197	21.6	1.0	0	4.5	6.9	1.20
H Fateh SW Injected-Gas Blowdown (U.A.E. Onshore)	300	33	1.0	0	0.9	10.9	1.22
I Oseberg Injected-Gas Blowdown (Norway Offshore)	3,811	418	1.0	0	4.0	134.0	1.34

Table C-11 — Summary of Resource Costs for Associated Gas (continued)

Field	Raw Reserves (bcf)	Daily Raw Prod. (MMcfd)	Non-HC Gases (%)	Cond. (bbl/MMcf)	Plant Shrink (%)	Net Gas (bcf/Yr)	Sales Gas ($/Mcf)
J Onshore Solution Gas Field (Nigeria)	275	30	1.0	0	4.5	9.6	2.26
K Onshore Solution Gas Close to PL (Venezuela)	54	5.9	1.0	0	4.5	1.9	2.32
L Onshore Solution Gas Close to PL (Trinidad)	36	3.9	1.0	0	4.5	1.2	2.44
M Onshore Solution Gas Field (Argentina)	226	25	1.0	0	4.5	7.9	2.81
N Delta South Gas Cap Blowdown (Nigeria Offshore)	1,080	118	1.0	10	4.5	37.8	3.03
O Offshore Solution Gas Field (Nigeria)	136	15	1.0	0	4.5	4.8	3.37
P Onshore Solution Gas Field (Trinidad)	36	3.9	1.0	0	4.5	1.2	3.70
Q La Paz Solution Gas (Venezuela Onshore)	54	5.9	1.0	0	4.5	1.9	3.83

Note: The examples above are illustrative of the cost required to produce and market for export gas production associated with typical oil fields. Assumed investments include new pipelines and gas processing plants.

APPENDIX D: IMPLICATIONS OF GAS DEVELOPMENT COSTS FOR METHANOL CONVERSION

BACKGROUND

One of the potential U.S. markets for a foreign gas export project is motor-vehicle transportation. Natural gas derivatives would compete in this market with gasoline or diesel fuel. This section estimates the cost of methanol landed at a U.S. port after conversion from natural gas and transportation via tanker.

Methanol export costs from eight gas-producing regions to the nearest U.S. ports are reviewed here. An example port that is or may be a gas pipeline terminus is used for distance calculations:

- Venezuela/Trinidad (Puerta La Cruz, Venezuela).
- Tierra del Fuego (Punta Arenas, Chile).
- West Africa (Port Harcourt, Nigeria).
- North Africa (Arzew, Algeria).
- Russia (Murmansk).
- Russia/Kazakhstan (Novorossysk, Russia).
- Russia/Sakhalin (Okha).
- Persian Gulf (Umm Said, Qatar).
- Southeast Asia (Singapore).

Murmansk (Barents Sea) and Novorossysk (Black Sea) could potentially access the same natural gas resource base through the Russian pipeline grid.

Methanol is an alcohol of methane and may be used as a high-purity chemical product, directly as a fuel or additive to gasoline, or as a feedstock for methyl tertiary butyl ether (MTBE). The feedstock synthesis gas for methanol production is a chief determinant of the particular process system used. Light feedstocks such as methane are commonly processed by steam reforming and some combination with catalytic partial oxidation.

Most modern methanol plants use a low-pressure process operating at between 750 and 1500 psi and between 230 and 280 degrees centigrade. Fuel-grade methanol requires less water removal and may contain higher alcohols and ethers. CO_2 is both an intermediate product and a synthesis gas used in the methanol production process. Removal of CO_2 and N_2 prior to methanol conversion is not necessary.

Low-pressure combination reforming methanol plants consume 28 to 30 MMBtu per metric ton of methanol produced. Large-scale plants based on conceptual designs using advanced processing schemes are predicted to consume 29 to 31 MMBtu per metric ton, but achieve significant capital cost savings. A conversion factor of 0.090 Mscf feedstock gas consumption per gallon of methanol produced has been assumed for both processes. A metric ton of methanol is approximately equal to 333 gallons.

A methanol export project requires large front-end investments in a gas conversion plant, marine terminals, tankers, and storage facilities, as well as infrastructure support. Cost estimates presented here are based on a current, standard 2,500-short-ton-per-day plant (302 gallons per short ton) and a conceptual 10,000-metric-ton-per-day advanced process plant. Such plants will consume 73 MMcfd and 300 MMcfd of feedstock gas, respectively. The cost estimates in this section are consistent with a companion report prepared for DOE as part of the Alternative Fuels Assessment project: *Technical Report Three: Methanol Production and Transportation Costs.*

Methanol Conversion

Methanol processing plant costs presented here are for fuel-grade conversions. Current world-scale methanol plant designs are sized in the range of 2,000 to 2,500 metric tons per day (MTPD). The technology of methanol production is well known and it is possible to build single train plants with capacity of up to 3,000 MTPD. A field producing 100 MMcfd could supply 3,336 MTPD of methanol. Two sets of cost estimates are shown here:

1. A current technology, 2,500-short-ton-per-day steam reforming plant, total costs if built on U.S. Gulf Coast (1988 dollars): $229MM.
2. An advanced technology, 10,000-metric-ton-per-day plant, total costs if built on U.S. Gulf Coast (1988 dollars): $588MM.

The advanced technology plant example is based on a design that makes use of improved process technology as well as some economies of scale. Such a plant is assumed to operate at a higher pressure and achieve significant savings in gas compression costs. Synthesis gas generation is assumed to require two trains, but methanol synthesis and purification are essentially single trains.

A methanol plant investment may be divided into the "Inside Battery Limits" (ISBL) equipment required to transform the raw gas feedstock into methanol, and "Outside Battery Limits" (OSBL) facilities such as utilities, buildings, water and electrical systems, and product storage. ISBL costs make up two-thirds of the total plant cost in our Gulf Coast example. Infrastructure investments required in remote locations, including tanker accommodations, are added to OSBL costs in these examples. Each regional example plant investment has been adjusted to reflect expected local construction cost in that area. Additional plant costs include annual direct operating and maintenance costs at about 6.0 percent of ISBL capital expenditures plus overhead, insurance, and property taxes. Operating time is assumed to be 91 percent.

Total methanol plant expenditures have been translated into a dollars-per-gallon-of-methanol product for the purposes of this report. The overall required real rate of return on the investment is expected to be 10 percent based on a 15-year project life, depreciation at 5 years straight line for the ISBL equipment, 15 years straight line depreciation for OSBL, and an income tax rate of 37 percent. This return may be achieved by financing with a nominal return on equity of 20 percent and 40 percent debt financing at 10 percent, with inflation of 5 percent per year. The equivalent annual capital charge is about 20 percent of the total investment.

The methanol conversion plant in these examples is capable of processing most nonsour gases. Field development costs in this report include gas processing plants at the field prior to pipeline transmission. Optimizing these facilities with the methanol conversion equipment may allow some cost savings.

Per-gallon methanol synthesis charges are listed in Table D–1 for the example location and plant sizes.

Table D–1 — Methanol Conversion Costs

Methanol Plant Location	2,500-STPD Plant Capital Cost ($ million)	2,500-STPD Plant Synthesis Charges ($/gal)	10,000-MTPD Plant Capital Cost ($ million)	10,000-MTPD Plant Synthesis Charges ($/gal)
Venezuela (Puerta La Cruz)	266	0.30	679	0.18
Tierra del Fuego (Punta Arenas)	357	0.30	919	0.24
Nigeria (Port Harcourt)	515	0.53	1,323	0.33
Algeria (Arzew)	266	0.30	679	0.18
Russia (Murmansk)	515	0.53	1,323	0.33
Russia (Novorossysk)	357	0.38	919	0.24
Russia/Sakhalin (Okha)	357	0.30	919	0.18
Persian Gulf (Umm Said)	357	0.38	919	0.24
Southeast Asia (Singapore)	266	0.30	679	0.18

Table D–2 — Methanol Transportation Costs

	U.S. Port			
	New Orleans		Baltimore	
Methanol Plant Location	Distance (mi)	Costs $/gal	Distance (mi)	Costs $/gal
Venezuela (Puerta La Cruz)	1,958	0.025	1,900	0.024
Tierra del Fuego (Punta Arenas)	7,307	0.075	7,002	0.071
Nigeria (Port Harcourt)	6,058	0.064	5,259	0.055
Algeria (Arzew)	4,808	0.050	3,594	0.039
Russia (Murmansk)	5,502	0.057	4,279	0.046
Russia (Novorossysk)	6,810	0.068	5,735	0.059
Persian Gulf (Umm Said)	9,567	0.100	8,492	0.095
	New Orleans		Los Angeles	
Methanol Plant Location	Distance (mi)	Costs $/gal	Distance (mi)	Costs $/gal
Southeast Asia (Singapore)	11,937	0.112	7,867	0.079
Russia/Sakhalin (Okha)	8,519	0.095	4,640	0.049

Methanol Transportation

To estimate the total dollar-per-gallon charge for methanol delivery into the wholesale U.S. market, shipping costs must be added. The volume of methanol that may be exported annually with a single tanker is directly related to the distance to market and the size of the tankers employed. Typical petroleum product carriers are sized at 40,000 DWT, although VLCC-type vessels sized up to 140,000 DWT are possible. Shipping costs presented here are based on newly built 40,000-DWT tankers dedicated to an export project. Each tanker designed for fuel-grade methanol transport is assumed to cost $23 million (1988 dollars). The annual capital charge estimated for each tanker is approximately 16 percent. This is somewhat less than the capital charge estimated for the conversion plant because the tankers are assumed to be financed with a greater debt percentage.

Fuel consumption is based on diesel engines and an average speed of 12 knots. Turnaround time is estimated to be 2 days per trip, and total operating time is 91 percent of the year (332 days). These estimates do not include unscheduled repair or port delays. Table D–2 outlines methanol transportation costs to example U.S. ports.

The distances noted above are nautical miles one way. Costs for transportation from Southeast Asia and Sakhalin to New Orleans include the cost of Panama Canal transit. Costs for transportation from the Persian Gulf include Suez Canal transit. As Table D–2 indicates, transportation charges become a major portion of methanol costs as distances increase.

SUMMARY

Costs presented here are representative of the cost of methanol delivered to the wholesale-level distribution point, comparable to the refinery gate cost of gasoline. These methanol costs would compete with wholesale gasoline costs, before distribution costs and taxes. Methanol has roughly 50 percent of the heating value of gasoline. If used directly as a substitute for gasoline, about twice as much methanol is required. Therefore, if wholesale gasoline prices are $0.70 per gallon, methanol would have to be priced at $0.35 per gallon, assuming no tax differences. Conversely, if the delivered cost of methanol is $0.35 per gallon, its wholesale gasoline equivalent price would be $0.70 per gallon.

The total costs of production, transportation to the export point, conversion to methanol, and transportation to the U.S. for an example gas development are illustrated in Table D–3. All of the examples in this section are for transportation with 40,000-DWT tankers. Transportation costs are reduced approximately 10 percent for each doubling in capacity of the tankers.

The conversion and transportation costs developed in this section may be applied to the estimates of undeveloped gas potential in Table S–2 to estimate prices and volumes of methanol potentially available for export from these example countries. Tables D–4 through D–6 contain estimates of total methanol availability at a gas extraction cost of $1 per Mcf and annual volumes available at a field production rate equivalent to an R/P ratio of 25 for the example regions described in this section.

Table D–3 — Cost of Methanol Calculation for Methanol Delivery From Algeria to Baltimore

Location	Volume Available	Capital and O & M Costs (1988$)	Gas Losses (%)	Cumulative Cost (after losses) (1988$)	Volume Remaining	Processing/ Transportation Step
Gas plant inlet	100 bcf methane gas	0.98/MMBtu (field gas dev.)	2.0% Field, PL use	1.00	98 bcf	Production and transportation to export point
Methanol plant in Algeria	98 bcf	0.300/gallon (conversion)	Included in conversion to methanol	0.390/gallon	8.82 million gallons methanol	Methanol conversion
Methanol terminal landing in the United States	8.82 million gallons methanol	0.039/gallon (transport)	Diesel fuel ship propulsion	0.429/gallon	8.82 million gallons methanol	Tanker transport
Wholesale gasoline equivalents	4.41 million gallons gasoline equivalent	—	—	0.858/gallon wholesale gasoline equivalent	—	—

Note: Based on pipeline transport of gas to export point, tanker transport to Baltimore, after conversion to methanol (standard technology) at export point.

Table D-4 — Estimates of Undeveloped Nonassociated Gas Cost of Methanol Conversion and Delivery to the United States—Baltimore

Country	Undeveloped Nonassociated Sales Gas Resource Cost < $1/Mcf (tcf)	Feedstock Cost if Gas Production Cost $1/Mcf ($/gal)	Methanol Production Cost Standard Tech. ($/gal)	Methanol Production Cost Advanced Tech. ($/gal)	Transportation Cost ($/gal)	U.S. Landed Methanol Cost if Gas Production Cost $1/Mcf Standard Tech. ($/gal)	U.S. Landed Methanol Cost if Gas Production Cost $1/Mcf Advanced Tech. ($/gal)	Volume Available at R/P = 25 (MM gal/yr)
Abu Dhabi (U.A.E.)	35.0	0.09	0.38	0.24	0.095	0.565	0.425	15,556
Algeria	15.0	0.09	0.30	0.18	0.039	0.429	0.309	6,667
Argentina (Tierra del Fuego)	7.0	0.09	0.38	0.24	0.071	0.541	0.401	3,111
Chile (with blowdown gas)	5.8	0.09	0.38	0.24	0.071	0.541	0.401	2,578
Iran	296.0	0.09	0.38	0.24	0.095	0.565	0.425	131,556
Libya	3.5	0.09	0.30	0.24	0.039	0.429	0.369	1,556
Nigeria	9.9	0.09	0.53	0.33	0.055	0.675	0.475	4,400
Qatar	127.6	0.09	0.38	0.24	0.095	0.565	0.425	56,711
Saudi Arabia	96.3	0.09	0.38	0.24	0.095	0.565	0.425	42,800
Trinidad and Tobago	1.9	0.09	0.30	0.18	0.024	0.414	0.294	844
U.A.E. (others)	6.7	0.09	0.38	0.24	0.095	0.565	0.425	2,978
Russia (Murmansk export)	9.0	0.09	0.53	0.33	0.046	0.666	0.466	4,000
(Novorossysk export)	*	0.09	0.38	0.24	0.059	0.529	0.389	*
Venezuela	1.3	0.09	0.30	0.18	0.024	0.414	0.294	578

Notes: Standard/advanced technology refers to methanol conversion process.
Transportation assumed in 40,000-DWT tankers.

*Russia Murmansk/Novorossysk exports utilize same gas resource base.

Table D-5 — Estimates of Undeveloped Nonassociated Gas Cost of Methanol Conversion and Delivery to the United States—New Orleans

Country	Undeveloped Nonassociated Sales Gas Resource Cost < $1/Mcf (tcf)	Feedstock Cost if Gas Production Cost $1/Mcf ($/gal)	Methanol Production Cost Standard Tech. ($/gal)	Methanol Production Cost Advanced Tech. ($/gal)	Transportation Cost ($/gal)	U.S. Landed Methanol Cost if Gas Production Cost $1/Mcf Standard Tech. ($/gal)	U.S. Landed Methanol Cost if Gas Production Cost $1/Mcf Advanced Tech. ($/gal)	Volume Available at R/P = 25 (MM gal/yr)
Abu Dhabi (U.A.E.)	35.0	0.09	0.38	0.24	0.100	0.570	0.430	15,556
Algeria	15.0	0.09	0.30	0.18	0.050	0.440	0.320	6,667
Argentina (Tierra del Fuego)	7.0	0.09	0.38	0.24	0.075	0.545	0.405	3,111
Australia (NW Shelf)	4.2	0.09	0.38	0.24	0.112	0.582	0.442	1,867
Chile (with blowdown gas)	5.8	0.09	0.38	0.24	0.075	0.545	0.405	2,578
Indonesia	14.4	0.09	0.30	0.18	0.112	0.502	0.382	6,400
Iran	296.0	0.09	0.38	0.24	0.100	0.570	0.430	131,556
Libya	3.5	0.09	0.30	0.24	0.050	0.440	0.380	1,556
Malaysia	6.1	0.09	0.38	0.24	0.112	0.582	0.442	2,711
Nigeria	9.9	0.09	0.53	0.33	0.064	0.684	0.484	4,400
Qatar	127.6	0.09	0.38	0.24	0.100	0.570	0.430	56,711
Saudi Arabia	96.3	0.09	0.38	0.24	0.100	0.570	0.430	42,800
Trinidad and Tobago	1.9	0.09	0.30	0.18	0.025	0.415	0.295	844
U.A.E. (others)	6.7	0.09	0.38	0.24	0.100	0.570	0.430	2,978
Russia (Murmansk export)	9.0	0.09	0.53	0.33	0.057	0.677	0.477	4,000
Russia (Novorossysk export)	*	0.09	0.38	0.24	0.068	0.538	0.398	*
Russia (Sakhalin export)	0.6	0.09	0.38	0.24	0.095	0.565	0.425	267
Venezuela	1.3	0.09	0.30	0.18	0.025	0.415	0.295	578

Notes: Standard/advanced technology refers to methanol conversion process.
Transportation assumed in 40,000-DWT tankers.

*Russia Murmansk/Novorossysk exports utilize same gas resource base.

Table D-6 — Estimates of Undeveloped Nonassociated Gas Cost of Methanol Conversion and Delivery to the United States—Los Angeles

Country	Undeveloped Nonassociated Sales Gas Resource Cost < $1/Mcf (tcf)	Feedstock Cost if Gas Production Cost $1/Mcf ($/gal)	Methanol Production Cost Standard Tech. ($/gal)	Methanol Production Cost Advanced Tech. ($/gal)	Transportation Cost ($/gal)	U.S. Landed Methanol Cost if Gas Production Cost $1/Mcf Standard Tech. ($/gal)	U.S. Landed Methanol Cost if Gas Production Cost $1/Mcf Advanced Tech. ($/gal)	Volume Available at R/P = 25 (MM gal/yr)
Argentina (Tierra del Fuego)	7.0	0.09	0.38	0.24	0.062	0.532	0.392	3,111
Australia (NW Shelf)	4.2	0.09	0.38	0.24	0.079	0.549	0.409	1,867
Chile (with blowdown gas)	5.8	0.09	0.38	0.24	0.062	0.532	0.392	2,578
Indonesia	14.4	0.09	0.30	0.18	0.079	0.469	0.349	6,400
Malaysia	6.1	0.09	0.38	0.24	0.079	0.549	0.409	2,711
Russia (Sakhalin export)	0.6	0.09	0.38	0.24	0.049	0.519	0.379	267

Notes: Standard/advanced technology refers to methanol conversion process.
Transportation assumed in 40,000-DWT tankers.

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