Promoting Investment for Natural Gas Exploration and Production in Developing Countries

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ABSTRACT

This paper describes various means of interesting multinational oil companies or other private investors in natural gas prospects in developing countries. It is written from the perspective of the oil companies and it focuses on the financial analyses that they perform in evaluating natural gas prospects. The paper also introduces the considerations given by oil companies to the degree of hydrocarbon experience or sophistication of the countries. It discusses from a non-quantitative point-of-view the incentives, especially rapid payback, that the companies are looking for that would make various gas prospects attractive.

This paper is limited to the upstream or exploration and production phases of the natural gas business although it points out that one of the distinctions between oil and gas is that the latter requires an elaborate infrastructure, including pipeline transmission and distribution systems, to enable its marketability.

The paper is intended to serve as an informative piece for Bank staff and for officials in developing countries so that they fully understand the perspective of oil companies in evaluating gas exploration and production prospects and therefore are in a better position to adopt appropriate measures that would attract oil companies' participation.
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There are now more than 40 developing countries in which significant gas resources have been identified. The purpose of this paper is to determine various means of interesting multinational oil companies in actively pursuing natural gas prospects in both developing countries where prospects have been identified and in those countries which are gas prone, but where gas resources have not yet been identified. The author has taken the perspective of a private oil company whose methodology may differ from that of developing countries and even the World Bank.

This paper addresses the problems of attracting private investment capital to gas prone developing countries by focusing on the economic and financial criteria used by multinational oil companies at various stages of the exploration and development process to determine whether they should initiate or continue a hydrocarbon investment. The paper also focuses on the stages of developing country sophistication regarding hydrocarbon exploration and the incentives available to attract new private investment. It concludes by describing how the analytical techniques of the oil companies interface with the level of hydrocarbon sophistication (i.e., knowledge of potential hydrocarbon resources and experience with oil companies) of a developing country to determine the financial, economic and contractual incentives that need be offered to the companies to explore for and develop gas reserves.

Section II sets forth the economic and financial techniques used by multinational oil companies to analyze investment opportunities. It explains the importance of determining the marginal cost of a project and the cost of capital to the firm. It then explains three forms of investment analysis commonly used by oil companies to categorize oil and gas projects: net present value, internal rate of return and payback. This section also sets forth the implications of employing these analytical tools for the exploration and development stages of an oil or gas project.

Section III examines the distinction between an oil or gas project in terms of the analytical tools noted in Section II. It examines associated gas development, non-associated gas, and natural gas liquids projects.

Section IV examines the different degrees of hydrocarbon sophistication found in developing countries. The examination focuses on countries with limited sophistication, countries with proven non-exportable oil, countries with proven exportable oil or gas, and countries with proven non-exportable natural gas.

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Section V sets forth the appropriate steps developing countries may take to attract private investment for the exploration and development of a natural gas project. These steps are discussed in terms of the level of hydrocarbon sophistication of the developing country as well as the stage of the exploration and development process for which private investment is being sought. The steps include drilling of the initial test well, drilling of step-out wells, development of the field, and gas plant and transmission line construction. Particular attention is given to improving the payback to a private investor by shifting the percentages of ownership interest in a natural gas project and by offering tax incentives. Specific contractual arrangements are not within the purview of this paper and could well be the subject of a companion piece to be published in the future. However, for clarification purposes, the footnote below explains certain general contractual terms used in this paper.  

The brief Conclusion (Section VI) summarizes the importance of focusing on the points discussed in the paper in determining the optimal incentives for attracting private investment for natural gas projects.

2/ Concessions - These are the traditional forms of arrangement, which are still used in over 100 countries (including OECD countries) at the present time. The concessionaire has rights to the oil and gas found, and is subject to taxes, additional taxes on income, and royalties. A national oil company is often entitled to decide to participate (e.g. by way of a joint venture) at the exploration or production stage, whereupon it generally pays its share of costs.

Production-Sharing Contracts - Under the contracts, a portion (often up to a limit) of production is normally first allocated towards cost recovery; thereafter production of petroleum is divided between the government and the contractor, often on a sliding scale in relation to production levels. The contractor is then liable to income tax.

Risk-Service Contracts - All of the production accrues to the government but the contractor usually receives a cash fee (net after tax) per barrel etc. found and produced; (the fee may be delivered in kind (oil) at the contractor's request.)

Service Contracts - These are used only in production situations, either as a fee for services rendered, or as a fee per barrel etc. produced.
II. The Economic and Financial Goals of Multinational Oil and Natural Gas Companies

Most studies of natural gas exploration and development begin the analysis by discussing the profound physical differences and consequent economic differences between oil and natural gas. However, most multinational oil companies do not focus on the differences between oil and gas until after an investment prospect has cleared a series of economic and financial hurdles. These economic and financial criteria are of paramount importance to the multinational oil company. The refusal of a company to conduct seismic exploration in a gas prone area, drill an initial exploratory well, drill additional wells to define the extent of a gas discovery, or develop a discovery can be traced back to the company's perception that the incremental expenditure of investment funds for these purposes would not achieve a pre-established target rate of return.

Most multinational oil companies analyze every additional step of an oil or gas exploration and development program in terms of the before tax and after tax rate of returns to the company. The large sums of money involved in these investments require oil companies to continually review the rates of return for these investments. However, even the substantial funds already invested in a project do not "tie down" the company and require it to stay in a project when the investment return falls below a target level. Just the opposite is true. The large dollar expenditures involved in every incremental investment decision dictate that the oil companies cannot afford to make decisions based solely on the sunk costs associated with the investment.

Marginal Cost Related to Risk

Like other companies contemplating an investment, the planning and financial analyses of oil companies focus on the marginal cost of operations and the implication of marginal cost on the rate of return to the company. This is true for every step of an oil or gas exploration and development investment but there are some considerations endemic to the oil industry.

The marginal cost to an oil company of investing in an oil or gas project is viewed in terms of the implicit rate of return from the project as it compares to the company's cost of capital. To this end, every project is categorized in terms of the risk associated with the investment (which is has different risk factors in for the non-oil sector). That is, exploration investments are classified as the highest risk due to the geological uncertainty; development and production expenditures where the hydrocarbon has already been identified fall respectively into lower risk categories. Even within categories, further risk classifications may occur as regards political and currency risks. These represent far different risks than geological ones, and to a certain extent can be considered more negatively than geological risks to which companies are accustomed. Each category of risk is viewed in terms of the marginal return to the company expected from the incremental investment made for the subject project.
To this end, budgets are created which in turn are divided into categories relating to the different stages of the exploration, development and producing effort. This categorization is done because of the different risk levels associated with each of these stages. The higher the risk of a category of investment (e.g. drilling wildcat wells as compared to drilling wells which define the extent of a proved hydrocarbon basin) the higher the expected rate of return needed to justify the investment. If low forecast hydrocarbon prices reduce the rates of return over the life of projects of similar duration, then the higher risk investments are usually sacrificed before the low risk investments.

Cost of Capital Comparison

Oil company management determines the expenditures to be made in each category with a view to having the combined investment portfolio achieve a rate of return in excess of the company's minimum target rate of return. Generally, the target rate of return equals the company's weighted cost of capital. In both theory and fact the company looks for investment options which will give its shareholders a return on their investment in excess of the cost to the company of borrowing funds (debt and equity) to make these investments.

Oil companies have different weighted costs of capital depending on their credit ratings and their past return on investments. Additionally, the cost of capital will vary according to the duration of the investment. For example, a company may face comparatively low cost of raising short term capital and comparatively high costs of raising long term capital because of its existing debt structure or for other reasons. Whatever the specific cost of capital, each new investment decision is analyzed in terms of whether or not it will yield a return on the investment over its life which equals or better the cost to the company of its weighted average cost of capital including equity and debt. Companies use various means to calculate their costs of equity for the company which is not related to the specific project.

What this means for the exploration and production operations of an oil company is that planning assumptions and investment prioritization in terms of rates of return are critical. One common method of return analysis is described below.

Rate of Return Analysis: Net Present Value and Internal Rate of Return

First, the company establishes its best guess as to the future course of oil and gas prices adjusted for dollar denominated inflation. It may even give high, medium and low price assumptions and require that each project be analyzed under each separate price scenario. The scenarios may take the form of specific base prices for a thirty year period or specific prices for a five year period with annual escalation or de-escalation set beyond the first five years.
The expected price of oil or gas to be obtained from each investment is deduced on the basis of how the oil or gas compares in quality to the base-priced oil or gas. In the case of gas located outside of the United States, a projected contractual price for gas may be substituted. The absence of an existing gas contract price does not stop the analysis of a gas project.

Using these base prices, a cash flow analysis is conducted covering the expected useful life of each investment. For each year of the expected life of the investment a separate cash flow is projected wherein gross revenues from the project for that year are reduced by projected expenditures, overhead, operating costs, royalties and taxes associated with the investment. The resulting figure shows a net cash flow from the investment for each year of its life. This figure is broken down into its pre-tax and after-tax components so that comparisons between projects can be done on both bases and also to show the relative importance of local taxes levied on the project.

Once net cash flow has been determined for each year of the project life, the company conducts three analyses using these figures: the net present value calculation, the discounted cash flow rate of return (also known as the internal rate of return) and the payback period.

The net present value calculation is the sum of the present values of the cash flows from the project for all years. The cash flow figures are discounted to take into consideration the value of money to the company. This means that the cash flows of the project are discounted at a rate equal to the company's cost of capital. The result is a net present value dollar denominated figure which states the "value" of the project. The lower the discount rate (i.e. the lower the company's cost of capital) the higher the net present value of the cash flows from the project. When the net present value of a project is equal to zero it means that the rate of return from the project is equal to the discount rate. The company will only consider projects with net present values greater than zero and will prioritize projects in terms of declining net present values per dollar invested.

These same cash flows are then used to determine the discounted cash flow rate of return, also known as the internal rate of return, which is a percentage calculation as compared to the dollar net present value figure. The discounted cash flow rate of return is the rate of interest which would equalize the present value of net cash generated by the project with the present value of net cash invested in the project. It is akin to viewing the project as a cash generator or cash user over time, with money invested in one year generating a cash flow which, in turn, is being reinvested in the project for the next year. The internal rate of return is that interest rate which would, if the money for the investment had been placed in a investment generating equal annual payments, give the company as much total money at the end of the investment's duration as it will receive from accumulating the positive net cash flow and reinvesting it each year at the same interest rate.

As with the net present value determination, all projects in a category are prioritized along lines of their internal rate of return, with projects having the higher rate of return receiving priority over comparable
projects having lower rates of return. All projects must meet a minimum rate of return sufficient to cover weighted cost of capital in the firm. In addition, some companies assign probabilities to actually earning this rate of return, and these probabilities are then figured into the prioritization process.

Payback Period

The third use of annual cash flow figures is to determine how quickly the company will recoup its investment in a project. That is, to determine how long a period of time the company's money is at risk in the investment. The annual cash flow figures are often broken down into monthly figures to provide a more exact determination as to when the present value of the cash flow generated from the investment will equal the cash invested in that project.

Each project is prioritized as to payback period, with projects having the shorter payback period taking priority over those with longer payback periods. Unlike the other two forms of analyses, there is no cutoff point for projects in terms of payback period. Instead, the payback period analysis is used to complete the comparison of projects which otherwise may be similar in terms of net present value per dollar invested or discounted rate of return analysis. Payback analysis is of special importance when considering projects in countries perceived to have high political risk. It also is important to non-associated gas investments where the price obtained on the sale of the gas is viewed as a politically sensitive issue, subject to potential abrogation of contract, the case when the gas is sold for domestic consumption to the host government or its state gas company.

Implications of Rate of Return and Payback Analyses

Underlying all of the rate of return analyses noted above is the assumption that there are alternative exploration and development investments competing for the scarce financial resources of the oil company. The company's resources are allocated to investments yielding the highest return for their perceived risk level. Prioritization of comparable investments is the key to planning and projected cash flow is the mechanism for this prioritization.

The project with the highest net present value need not be the one with the highest discounted cash flow rate of return nor have the shortest payback. Scarcity of financial resources may mean that a large project with a high net present value will be sacrificed in favor of a smaller project with a higher discounted cash flow rate of return. In most cases, other things being equal, projects which generate positive net cash flow in the early years are favored over other comparable projects. The exceptions are those cases where for strategic planning reasons the company goes forward with a project that does not meet this financial payback criteria. Such reasons can include the company's desire to augment its presence in a country, better balance the timing of its financial commitments or protect its oil interests by developing a somewhat less attractive gas prospect in the country.
Implications for the Exploration Stage

The above noted analytical factors are used by the oil company at every stage of the exploration and development decision making process. At the very early stages of exploration (seismic and the initial test well) uncertainty as to the size of the geological structure being sought is augmented by uncertainty as to whether commercial quantities of oil, natural gas, both or neither will be found. The high level of risk (i.e. the high level of geological and commercial uncertainty) for all exploration projects means that the projected rate of return used to prioritize these projects can be called into question by management. In short, for seismic expenditures and rank wildcat well expenditures, the oil company management recognizes that prioritization of projects is far less exact than is the case for development projects.

Countries which have not had extensive oil and gas exploration efforts are vulnerable to early elimination when being reviewed for exploration funding. This is especially true during a period of scarce financial resources due to a turnaround in oil prices. This situation can work to the disadvantage of developing countries. Often, the absence of proven hydrocarbon potential means that their geological risk classification is higher than for exploratory areas in countries with proved hydrocarbons. However, this is not necessarily the case.

First, there is a great deal of geological uncertainty for any hydrocarbon exploratory effort and the existence of a proven hydrocarbon reserve near the target area gives very little comfort to the geologist. Correspondingly, the absence of a proven hydrocarbon reserve does not necessarily eliminate a non-oil producing country's project. Also, since exploratory technology has advanced significantly in recent years, the existence of a few shallow, dry holes drilled in earlier years is no reason for an oil company to condemn an exploration area. However in many of the cases the geological uncertainty is augmented by contractual, political and fiscal uncertainties within the purview of the host government.

At the early stage of an exploration effort, fiscal and contractual factors are of great importance to an oil company's decision to proceed or to abandon its efforts. Unclear or uneconomic contractual terms relating to profit sharing royalties, cost recovery and local taxation may individually or together act to block consideration of a country's exploration area. This is especially true during periods of low oil prices when exploration budgets are reduced across the board. By contrast, it is in the country's interest to attract the greatest number of companies potentially interested in exploration. In this regard, any payments required of oil companies to purchase geological data or obtain other documentation should be minimized.

Uncertainties as to the broad provisions relating to oil exploration and development are compounded by uncertainty as to how the government of the non-oil producing country will interpret the terms of the contract, apply tax regulations once a discovery is made, or impose other restrictions such as the mandatory use of local goods and services or excessive training requirements. This means that a non-oil producing developing country cannot
expect to attract exploration dollars from oil companies by simply copying the rules and regulations of a successful oil producing developing country. Such rules and regulations have a history of interpretation and mutual understanding on the part of the oil company and the oil producing country's bureaucrats. The reduced level of uncertainty that flows from this history cannot be transferred to the non-oil-producing developing country especially when geology, geographic location and political situations may differ.

In fact, if the non-oil producing developing country simply copies these established contract terms and tax policies it may actually deter oil companies from conducting exploration. Oil companies may believe that if the non-oil-producing country expects agreement on such terms at the early stage of exploration, when no significant hydrocarbons have yet been discovered in the country, then the terms are likely to worsen if a significant commercial discovery is made.

Other implications of rate of return analyses for exploration projects focus on mandatory versus discretionary expenditures by the oil company and their impact on cash flow. These rates of return change over time as market forces affect evaluations of prospects; thus it is not possible to designate a uniform, fixed rate of return that a company seeks.

Implications for the Development Stage

For the oil company the implications of rate of return analyses for the development stage of a project are different than those for the early exploration stage. Expenditures on wells to delineate the extent of a reservoir and further expenditures for development of the field are both heavily dependent on the rate of return analyses. At this stage, because the nature of the hydrocarbon (oil and gas) and the broad extent of the reservoir are known; the price of the hydrocarbon (especially natural gas), expected development and production expenditures, as well as the fiscal policies of the host government, all become more important than was the case in the early exploration stage.

Also, at this point in the exploration and production effort the early positive projected cash flows take precedence over other criteria. This distinguishing factor usually means the most attractive natural gas investments will have a high discounted cash flow rate of return and a short payback period. It also means that development projects with early large capital investments (generating early negative cash flows) are placed at a distinct disadvantage when compared to other development projects where capital expenditures are spread out over the life of the project.

Also, during the development stage of an investment, the financial criteria of third parties become important to the oil company. Oil companies often seek project financing from banks or other third parties because of the large capital expenditures involved in developing an oil or gas discovery. In this case, the borrowing cost associated with the financing entity will be compared to the company's cost of capital and if it is more favorable, then it will substitute for the company's cost of capital. In the case of LNG or large scale pipeline development projects, third party financing may be provided by the purchaser.
Financing of a hydrocarbon development project may be recourse or non-recourse to the oil company. The decision as to whether or not the project debt should stand alone or be included as a debt obligation of the oil company will depend on the comparative rates charged by the third parties for both types of financing and the incremental effect of the additional borrowing on the company's overall debt structure.

In most cases, an oil company will seek project financing; that is, to have the project stand alone as the sole source of repaying the development loan from the third party. Third party financing sources generally rely on the same discounted cash flow rates of return, net present value and payback analyses as used by the oil companies. The price of the hydrocarbon, the volume of the reserves, the certainty of sale of the hydrocarbon and the operating expenses become critical in determining the amount of third party financing available for the project and the terms of the financing. It is also at this stage that natural gas development projects tend to lose out to development of crude oil for the reasons cited in Section III.
III. Natural Gas as Distinct From Crude Oil

From the oil company's perspective a natural gas discovery poses limitations on potential profits which are not the case for a crude oil discovery. First, natural gas does not have a worldwide market similar to the one available for crude oil because of transportation costs. It can cost four to five times as much to move a comparable amount of gas instead of oil over an equivalent distance in a large modern pipeline system. Over a comparable ocean distance it can cost up to fifteen times as much to move gas by tanker (LNG) as it would to move oil on a BTU basis.

For this reason the oil company must determine the demand or marketability for natural gas in the geographical region close to the discovery. The region around the discovery is economically delineated in terms of pipeline costs and the availability and pricing of alternative energy sources.

Second, if a significant regional demand for gas exists, then the company must determine the likely price to be obtained over time from sale of the gas. This price is used in the rate of return analyses along with projected development costs. Here again natural gas discoveries are at a disadvantage compared to oil. To the extent that a monopoly gas purchaser (e.g. a government utility) is involved, the oil company must assume that the price of gas may be politically sensitive and more uncertain than would be the case for exportable crude oil.

Third, the gas sale exposes the oil company to foreign currency risks which are not the case with exportable crude sales. This is a major deterrent for a potential oil company investor. Developing country gas sales for the domestic market are made in local currency. The oil companies prefer not to be paid in local currency because the local currency often cannot be converted into U.S. dollars or another readily marketable currency due to its unavailability or to the monetary restrictions of the developing country. Only those countries that either earn enough foreign currency from their exports or have foreign exchange accounts set aside for this purpose are able to provide an oil company with the desired foreign exchange remittances.

The result is that for cash flow analyses of gas projects, the likely price received for the gas is heavily discounted to take into consideration the lack of local currency convertibility. A similar discount is used by oil companies when considering oil projects in countries which do not allow the company to export its share of crude, but instead require the company to sell some or all of its share to the government in exchange for local currency. However, oil projects in countries that allow full export of the crude are not subject to such discounting in their cash flow analyses.

Fourth, the characteristics of field development place gas at a disadvantage. The initial recovery factor in an oil field is usually 20% to 30% of the reservoir. This means that further investments in production facilities are made at late stages in the life of the field in order to
increase the recovery. Oil development costs can be effectively deferred to later years when new price projections will determine the expenditure of funds. In a real sense, the initial development of an oil field relates only to the expenditures and projected income from development of no more than one-third of the potential reserves.

From a hydrocarbon engineering standpoint, the development of a natural gas field is far different than for an oil field since 70% to 80% of the recoverable gas reserves are obtained from the initial development expenditures whereas sequential investments can characterize oil field developments. This means that natural gas development projects have large up-front costs for development of the entire reservoir while the initial development costs for an oil field relate to a smaller reservoir recovery factor. Unfortunately, depletion of a gas reservoir does not occur at a faster rate than for an oil reservoir, so as to allow for a more rapid cost recovery that would bridge the differences in the up-front development costs. This results in high negative cash flows for the early years of the natural gas project. Meanwhile, the magnitude of the later positive cash flow years of the natural gas project is dependent on the highly uncertain price projections for the gas in those later years.

Thus, the costs of a natural gas development project are high and occur early in the project life, while the profitable years occur later in the project life where there is a high degree of uncertainty relating to the gas price. This mixture often results in natural gas projects showing a low discounted rate of return, long payback period and low net present value when compared to similar oil development projects.

**Associated Gas Development**

The development of associated gas, whereby natural gas is found associated in the same formation with oil and is necessarily produced at the same time as the oil, is different from the development of non-associated gas in that the economics of the oil/gas field clearly justify the development of the oil reservoir. Associated gas development focuses only on the excess natural gas which exists after considering the need to re-inject gas into the reservoir to improve oil recovery. In some cases, however, injection is not necessary or desirable, and the alternatives are either flaring, where permitted, or development of the gas. It is often, though not necessarily always the case, that the economic return to the host country and the oil company from the incremental oil recovered after gas injection is far higher than any profits foregone in not selling the natural gas. Thus, an engineering concern to both the host government and the oil company in such cases is the potentially negative impact of associated gas development on the optimal recovery of the crude oil, if it reduces the potential for economically optimal reinjection.

A further economic distinction between associated and nonassociated gas development is that associated gas production, by its nature, is not as predictable as nonassociated gas. This is because the underlying crude oil production determines the daily natural gas volumes produced. Temporary reductions in crude volumes mean concurrent reduction in natural gas volumes
produced. The failure to provide predictable gas volumes on a daily basis can undermine the marketability of the associated gas unless the producer designates minimum levels of contract volumes which the purchaser accepts. Depending on the characteristics of the field and the propensity of the government to reduce production, in certain cases the marketing uncertainties (beyond minimum guaranteed levels) can result in a lower average price when compared to the more reliable supply of nonassociated gas or alternative energy sources. Thus, the development of associated gas fields can be placed at a disadvantage when compared to nonassociated gas fields, in addition associated gas requires additional compression.

Natural Gas Liquids

If the natural gas found in a discovery contains a high proportion of condensates, then the oil company is dealing with a discovery which may be economically closer to crude oil than to dry gas. (Some condensates are indistinguishable from non-asphaltic light crude oil except that in a reservoir they are associated with sufficient methane at such pressure as to be found in the gas phase, until pressure is reduced.) Their profitability depends on size of the reservoir, geographic location and specifications. Like oil, gas condensates have a world market and are transportable by vessel at lower cost than natural gas. There are also gas fields with high proportions of natural gas liquids which are recovered through associated and non-associated gas treatment and are fractionated to produce liquefied petroleum gases (LPG or butanes and propane) and pentane plus (C5+).

However, there are few gas fields, with the exception of some large ones in Middle East OPEC countries, that are so rich in condensates and liquids as to justify their economic development without sale of the dry portion of the gas, although in some cases the nature of the liquids and the demand in the local market may mesh to allow for separate gas liquids development. This means that gas fields which are condensate/liquids-rich are analyzed by oil companies along the same lines as other gas fields except that the sale of the condensates and liquids is broken out as a separate cash flow item that improves the rate of return of the investment and shortens the payback period. Most importantly, if exportable, the condensates/liquids can provide the means for the company to earn foreign exchange from their project.

Thus, both the oil company and the host country should have a vested interest in exporting the condensates and liquids. Often, under production sharing agreements, the oil company will market the host government's share of condensates/liquids alleviating the government of establishing the infrastructure to handle them. Thus, condensates and liquids are viewed by the oil company as lowering the degree of currency risk of the project, especially as compared to a straight dry gas development project. (The same, of course, does not hold true if they can only be sold to a domestic market.)
IV. **Degree of Hydrocarbon Sophistication of Developing Countries**

The above discussion has set forth the analytical approach taken by oil companies at various stages of the exploration and development effort. Companies are aware of the high risk associated with all hydrocarbon exploratory efforts. They also know that rank wildcat exploration efforts, except in clearly gas-prone areas, cannot be clearly designated as being focused on either gas or oil.

Given these facts, developing countries should recognize that incentives for natural gas exploration will come into play only after basic incentives for general hydrocarbon exploration or development have proven effective. Each country is viewed by oil companies as having achieved a certain degree of hydrocarbon sophistication in terms of the extent of hydrocarbon exploration, development or production to which the country has been exposed. The best way of reviewing the situation of developing countries in this regard is to consider them as falling into one of the following groups: virgin countries devoid of any past hydrocarbon exploratory efforts, countries with limited and unsuccessful past exploratory efforts, countries with proven oil potential, countries with proven exportable oil, countries with proven exportable natural gas and countries with proven non-exportable natural gas. Coupled with their levels of sophistication is the degree of sophistication of the oil company in working internationally.

**Countries With No or Limited Hydrocarbon Sophistication**

Most developing countries have experienced at least some minimal exploratory interest (e.g. running of seismic surveys) during the 1974 through 1982 period of high crude oil prices. For purposes of this paper, the few countries devoid of any hydrocarbon exploration can be categorized along with those countries which had some unsuccessful exploratory efforts. In both cases, the country must focus on attracting oil companies to conduct preliminary hydrocarbon exploratory efforts.

The incentive offered by a country in such cases must focus on attracting oil companies to run seismic surveys to determine whether or not any hydrocarbon related geological structures exist. For oil companies, this type of seismic is akin to research and development expenditures. These expenditures will only be made if the results of the seismic can be kept confidential (i.e. revealed only to the host government) and if the host government will provide the company with priority in choosing and drilling exploratory wells on any structures revealed by the seismic.

**Countries with Proven Non-Exportable Oil**

Countries with proven non-exportable oil (i.e. where domestic demand for oil far exceeds oil production) are in a very different position from other countries. First, they have an established hydrocarbon contractual and
fiscal structure to attract the interest of oil companies willing to produce and sell crude in the host country. Second, they are viewed as oil prone countries so it may be assumed that some seismic efforts have been undertaken to determine the existence of geologically interesting structures.

It may be the case with these countries that small geological structures have been identified but not explored because projected developments even as oil discoveries would not be economic. In such cases, the fact that the discovered crude was judged not to be exportable may have prevented the drilling of a test well. However, it could also be that the size of the structures were so small as to make them uneconomic as single oil producers—though not necessarily as joint oil producing fields under favorable economic terms.

For these countries the goal is to attract the drilling of exploratory wells to determine the nature of the hydrocarbons in the geological structures revealed by seismic. While additional seismic may be needed, the key for these countries is to give the oil companies currently operating in their country the incentive to drill wells where they otherwise would not drill.

**Countries With Proven Exportable Oil and Gas**

Countries with large proven reserves of exportable crude are in the most advantageous position of any developing country interested in gas development. There are obvious strong economic incentives available to promote the development of the associated natural gas by the oil companies operating in their country. For example, the lure of additional oil exploration rights can be very appealing to the oil companies.

Countries with large proven reserves of exportable natural gas are likewise favored. They can offer strong incentives in terms of new exploration leases and fiscal incentives relating to current hydrocarbon production to benefit the oil company willing to undertake the added expense associated with the exploration and development of a gas field for local consumption.

However, it appears that few, if any, oil and gas rich countries offer adequate incentives for development of non-exportable natural gas. As an example, it appears that Indonesia is not providing incentives for domestic gas development. Recently, Union Texas abandoned a gas discovery in Indonesia under the Tomori production sharing contract in Sulawesi. Although the well flowed 18 million cubic feet per day of gas and 328 barrels a day of gas condensates, the well was abandoned. The reason given by Union Texas was the lack of a nearby gas market.

**Countries with Proven Non-Exportable Natural Gas**

Countries with proven non-exportable natural gas or natural gas that could be exported only to a country lacking convertible foreign exchange are at a clear disadvantage compared to their export-rich cousins. These countries must attract oil companies to develop reserves which they know exist.
but which can only serve the local market. In this case the countries will have to focus on supporting the oil company developing the field in terms of shortening the period for recoupment of the original investment, providing foreign currency priority for oil company profits and perhaps making available subsidized financing through multinational institutions. These countries are the major focus of Section V of this paper.

The above categories of hydrocarbon sophistication make more sense to an oil company than a general classification of gas prone countries. To an oil company, a gas prone geological basin implies that extensive exploratory efforts have been undertaken in the past so that it is likely, but not at all assured, that the drilling of new structures in the basin will yield gas. As noted above, such a basin may either be so large as to offer significant export potential or otherwise be restricted to regional gas demand only.

Thus, each developing country must focus on its own particular stage of hydrocarbon exploration before determining the best means of attracting oil companies to either explore or develop natural gas fields for local use. The incentives used by each country will differ according to the extent of their hydrocarbon development.

In addition, the level of international sophistication of the oil company is a factor. While countries do not want to screen out prospective companies, those that lack any experience in the oil sector might be better served by dealing with companies already familiar with the problems of operating internationally. They also may be more likely to accept certain provisions which would be unacceptable to a strictly national company. Likewise, companies which lack international experience may find the going easier by targeting countries with at least a moderate level of hydrocarbon sophistication.
V. **Appropriate Steps to Attract Private Sector Participation**

In Exploration and Development of Gas Reserves

This section of the paper shows how the interests of the developing countries can interact with the analytical techniques of the oil companies to provide effective incentives to attract oil companies to develop natural gas reserves for domestic use. For purposes of this section, two categories of countries are analyzed:

(a) the less hydrocarbon sophisticated countries which must attract oil companies to do preliminary seismic and drilling.

(b) the countries with proven non-exportable natural gas deposits.

The other types of countries—those with non-exportable oil, those with exportable natural gas or oil—will only be addressed in passing since they have available the same incentive techniques as used by these two categories of country and have additional incentive techniques available (noted above in Section IV) as a consequence of their hydrocarbon production.

**Countries With Limited Hydrocarbon Sophistication: Incentives for Drilling an Initial Test Well**

Countries with limited hydrocarbon sophistication have a significant tool they can use to attract further exploration and drilling for gas which may prove valuable for domestic use. That tool is the absence of significant oil and gas exploratory efforts in their country and the opportunity this offers the oil company. Virgin exploration territory offers the oil company an opportunity to enter at the ground floor of a potential hydrocarbon basin. This is particularly appealing to major oil companies on the lookout for potentially large oil reserves to feed their marketing and refining operations.

The developing country can offer one or more oil companies preference over others in conducting seismic and choosing top priority exploration areas. Usually such preference is tied to the seismic and drilling commitments entered into by the oil company. That is, an oil company that commits itself to run a certain number of miles of seismic and drill a test well may receive preference in the selection of additional exploration areas for seismic and drilling. The incentives that stimulate the oil company in these circumstances can be utilized to stimulate the same company to conduct additional seismic and drilling after an initial gas well has been drilled.

The typical exploration contract includes the following provisions. Country A enters into a seismic and test well commitment with oil company B. The contract requires Company B to run seismic in a certain area and may specify the number of miles of seismic required. If Company B chooses to drill an initial test well it will be given a specified time period to drill additional test wells prior to relinquishing a specified percentage of
the exploration area to Country A and then developing the hydrocarbon
discovery. This type of provision allows Country A to offer the relinquished
areas to other oil companies for further seismic and drilling.

An example of a contractual incentive for further natural gas
testing would be as follows. The same basic contract terms as noted above
would remain. However, if the initial test well proves to be a noncommercial
(i.e. non-exportable) natural gas producer, than Company B receives the right
to run seismic and drill a well on another unrelated exploration area of its
choosing. Further incentives for Company B to drill more wells to delineate
the gas find may be tied to the relinquishment provisions, as discussed below
for countries with proven non-exportable natural gas, or they may be tied to
minimum expenditure requirements.

Exploration contracts often include requirements to drill a minimum
number of wells on the lease and to expend a minimum dollar figure associated
with exploring the lease. The host government might consider giving special
credit to expenditures related to development drilling of a gas discovery in
order to provide an incentive for the oil company to undertake these
expenditures.

Thus, if the initial lease required one well and $10 million in
expenditures and a second lease sought by the company, or held by it, requires
an additional two wells and $20 million in minimum expenditures, the host
government might consider giving partial credit for the money spent drilling
gas development wells on the first lease as against the required expenditures
on the second lease. Perhaps a 50 percent credit would be given against each
dollar required to be spent on the second lease. There are variations to this
approach as well as for the relinquishment provision.

In the absence of exploratory efforts, the above approaches allow
the oil company to follow seismic leads wherever they may take them and to
drill wells necessary to test for large and potentially commercial oil
finds. The more virgin a territory the more important it is for the oil
company to follow such leads since incremental seismic expenditures have the
potential of leading to the sought-after large, geological structures. This
is less likely to be the case for countries where extensive exploratory
efforts have been undertaken in the recent past.

As noted earlier, it is important that the less hydrocarbon
sophisticated countries provide basic, but not detailed, contractual and
fiscal provisions for the oil company to feel confident that the rules of the
game are known. As each step of the exploration and development process is
completed, the details of the next step can be negotiated, provided that this
is done in a timely manner. Thus, the natural gas contract terms need not be
set forth in detail until such time as the oil company has taken the necessary
exploration and development drilling steps in order to make these details
relevant to the next step toward achieving production.

This step by step approach is not meant to imply that the host
country can, or should, tie the oil company into expenditures and then impose
burdens in the following stage of operations that would make the entire
investment uneconomic. Rather, it means that the broad outlines of a contract should be agreed to, perhaps with the provisions noted below. Arguments as to detailed provisions may only cause the oil company to hesitate to take the initial steps needed to make the detailed provisions relevant.

Countries with Proven Non-Exportable Natural Gas

Before discussing the special problem of incentives for development of a gas field, it is worth noting that some countries with proven non-exportable natural gas have unintentionally imposed disincentives for the exploration of these gas prone areas. These disincentives are tied to the distinction made between gas and oil under the basic production sharing contracts.

For example, until very recently Egypt distinguished between oil and gas to the effect that any discovered gas reserves automatically became the property of the state-owned Egyptian General Petroleum Corporation. In turn this meant the oil companies had no rights to develop or sell the gas. While this clause may have been meant to relate to associated gas discoveries, it had the effect of dissuading major oil companies from exploring in gas prone regions such as the Nile Delta. Oil companies began new exploration efforts in the gas prone areas only after Shell Oil negotiated a clause in the general exploration contract that gave the oil company the same rights to take the gas as it had for oil.

Once the natural gas discovery is made, the host country must provide incentives that provide an acceptable return for the oil company to continue to develop the discovery. This development takes the form of (a) drilling additional wells in the area to delineate the extent of the natural gas discovery, (b) complete the necessary development drilling for efficient reservoir production and the building of gas processing facilities, and (c) building a pipeline to take the processed dry natural gas to the purchaser.

Incentives for Drilling Step-Out Wells

Incentives for drilling additional wells to delineate the extent of a discovery (often termed step-out wells) in a less hydrocarbon sophisticated country may include concept of linking the drilling of these wells to new exploration efforts. For example, drilling additional step-out wells could earn the company the right to avoid relinquishing portions of the initial exploration area and might also allow the oil company to retain an additional exploration area for a period of time beyond the initial pre-relinquishment period. In other words, the desire to conduct additional seismic and drilling on other geological structures in the exploration area can be furthered by the drilling of step-out wells on the known natural gas geological structure.

The more sophisticated hydrocarbon country may not be in such an advantageous position. If most of its exploration areas have been condemned by previous testing, then the incentive of more exploration opportunity will not be as attractive. Although deeper drilling to test structures in
otherwise unpromising areas may be possible, this drilling may not be as attractive to the oil company as the lower cost drilling of a virgin area with shallower structures.

For hydrocarbon sophisticated countries, the drilling of step out and development wells for a natural gas discovery should provide the oil company with an immediate tangible economic return. For countries with producing oil (exportable or non-exportable), or exportable natural gas, the host country might offer an immediate benefit for drilling these wells tied to current production.

This benefit could take various forms and need not place any other company operating in the country at an economic disadvantage. For example, preference in marketing the host country’s profit share of crude oil or natural gas liquids may prove sufficient incentive for the drilling of additional wells to delineate an otherwise uneconomic (i.e. non-exportable) natural gas discovery. Oil companies are well aware that the drilling of one gas discovery does not necessarily condemn the entire structure as a gas discovery, nor can it be determinative as to the size of the reservoir. For this reason, oil prone and export gas prone countries usually have strong existing incentives to have oil companies currently operating in their country drill a few step-out wells to delineate a geological structure.

**Rapid Payback for Keeping the Rig On-Site**

Countries that do not have leverage from existing hydrocarbon production will have to focus on the analytical techniques used by oil companies set forth in this paper. First, the presence of the drilling rig on the site of the test well should be seen as an opportunity for the host country. The cost of drilling additional wells are likely to be at their lowest immediately after an initial test well has been drilled. For this reason the host country might consider offering to pay for all or part of the cost of drilling additional wells on the site. The financing of the additional costs might be handled by a multinational agency such as the World Bank. Likewise, other oil companies operating in a host country should be approached to participate in the drilling. The oil company conducting the original drilling could not complain since its alternative would be to abandon the exploration area absent additional drilling. Another important technique may be a contractual farmout of all or part of that company's interest in the exploration lease. This farmout could be arranged by the host country to a third party financing the new drilling.

If financial participation by the host country or a third party intermediary is unavailable, the country should consider means of providing the oil company with the necessary rate of return and payback for its investment to allow them to delineate and develop the lease area. As noted, for domestic natural gas projects the company will give priority to a quick return of its initial capital investment. The cash payback of development drilling expenditures must be assured for the oil company to drill step-out wells delineating a gas field which they know will not produce exportable gas, and which will require significant upfront cash investment in the form of a gas processing plant and pipeline construction.
Alternative approaches may prove effective in assuring a rapid payback to the oil company in this position. First, the oil company (or the drilling contractor) may agree to become a service company to the host government for the drilling of these development wells. This means that they would charge a fee (either for services rendered or as a fee per unit of hydrocarbon produced) for drilling the development wells and would be expected to be paid in hard currency or in exportable goods for their efforts. Again, if the host government does not have the necessary foreign currency or barter goods for this purpose it might consider borrowing the funds from a multilateral lending institution such as the World Bank, or obtaining an equity investor such as the IFC. In this situation, timing is critical since the drilling rig on the site may be leased on a daily basis. This could be of concern because of the World Bank's loan-processing time.

One way to give the host country more time would be for the initial exploration contract to have built into it a short (e.g. 30 day) time period following completion of the initial test well during which time the oil company must keep the rig, or a substitute rig, available for further drilling on the lease area. At the end of that period the host country must either have obtained sufficient financing to drill one or more additional wells or notify the company that the rig can be removed. If financing is found, the oil company would be committed either to drill the wells itself under a pre-arranged short term service contract or to obtain another driller to drill the wells. A limit on the number of additional test wells to be drilled under these circumstances as well as the cost of drilling the wells would be agreed to under the initial exploration lease prior to drilling the initial test well.

Such a provision could apply to either a natural gas or oil discovery where the oil company has chosen not to make a declaration of commerciality to the host government. Although this provision would raise the implicit cost to the oil company of undertaking the exploration, this cost need not be so prohibitive as to bar interest on the part of the companies. The additional wells would not be drilled unless the financing can be obtained.

Alternatively, the host country might negotiate a separate agreement with the drilling contractor in which the oil company could participate as a cost of exploring the lease. There are several options along these lines, and a careful review is needed so as not to offend oil companies that would bridle at being viewed, in a sense, as drilling contractors under a service contractual arrangement.

The availability of a rig on a lease site must be combined with host country access to contingency funds to pay for drilling these wells on short notice. Although not currently a World Bank practice, an optimal situation would be an arrangement with the World Bank to obtain financing as part of a development drilling contingency fund. Such a fund would authorize expenditures for drilling additional wells under pre-arranged minimal geological and economic standards for the test well (e.g. the initial gas well must have flowed a minimum amount of gas per hour for several days). Such funding would immediately be authorized up to a fixed dollar ceiling and
limitation on the number of additional wells to be drilled. For example, the fund might be limited to spending no more than, for example, $2 million for each additional well and to finance no more than two additional test wells following the drilling of the initial well.

Second, if the host country cannot obtain the necessary financing for development drilling it might consider providing partial financing, with the oil company retaining a percentage interest in the lease in exchange for providing the remainder of the drilling cost for a specified number of development wells. The percentage interest retained by the oil company could be larger than its proportional share of the drilling costs or it could take the form of an overriding royalty interest, rather than a working interest in the lease. In these ways the oil company would not feel tied to future expenditures associated with the development of the gas reserve.

Again, from the host country's perspective it is important that each step of the development process be undertaken as expeditiously as possible. Any attempt to tie down an oil company into commitments to build a processing plant or pipeline or to wait for the completion of any of these projects before it receives payment will only dissuade the company from taking the necessary next step in the development process.

Keeping the Company as a Participant

Up to the point of completing the development drilling to delineate the gas reserve, the oil company has not been concerned with the price of natural gas or costs associated with developing the gas. In effect, up to this point the oil company has been used for its drilling services. However, once the gas reserve has been delineated, the exploratory aspects of the project end, and the strict economic and financial concerns become paramount. It is also at this point that the oil company may choose to no longer maintain an equity interest in the gas lease and related gas project other than an overriding royalty interest, retained in exchange for covering part of the cost of drilling the delineation wells.

It is still in the interest of the host country to keep the oil company as an equity participant in the project. The oil company is likely to have significant expertise in the development and operation of the gas field, gas plant and related infrastructure. For this reason it may prove to be much cheaper to keep the oil company as an equity participant than to attempt to duplicate its expertise in the form of contracting out to third parties the gas plant and field operations.

Both the oil company and outside financing sources will view the domestic gas project in the same economic terms: net present value, discounted cash flow rate of return and payback of initial investment. For these purposes the price received for the gas sold to the host government or its state oil/gas company will be important since it composes part of the project revenues.
Gas Price—Take-or-Pay

Since there is no world market price for gas sold in the domestic or regional market, the price risk is not identical to that found in the crude oil market. Instead, price paid to the producer is often based on alternative BTU fuels that the gas would displace. For example, in the recent gas contract between the Egyptian Petroleum Corporation and Shell Oil a gas price based on the Mediterranean quotation for fuel oil was used, but a discount factor was also included. The key in pricing is to provide the supplier with an indexed price which is reasonable in terms of his expectation but which also allows the gas to be marketed.

Once price has been agreed it becomes important for the seller to feel assured that a certain volume of the gas will be purchased on a regular basis by his designated customer(s), which in the developing world is generally the national oil or gas company. Such assurances have taken the form of take-or-pay contracts wherein the purchaser commits to either take a minimum quantity of gas each period or, in the event the gas is not taken, pay the supplier the amount that would otherwise have been due to him. While these clauses were reasonable when initially inserted in gas contracts, they have been breached on many occasions because of the very high gas prices built into many of these early contracts and availability of lower priced gas in subsequent years. Many oil companies have renegotiated these gas contracts to avoid the court delays related to a challenge of the take-or-pay clause.

Although take-or-pay provisions would seem appropriate for developing country domestic gas usage, it is hard to believe that the oil companies, in view of their unfortunate experiences in the United States, will rely on these clauses for anything more than cold comfort in the developing countries. Nonetheless, some purchase assurances are needed for the company to obtain financing for the gas development particularly if new infrastructure or downstream facilities are needed. It should be noted, however, that Shell Oil included a take-or-pay provision in its recent contract with the Egyptian Petroleum Corporation (referenced above). In that case, the discount factor used against the index price may be so significant as to reinforce the take-or-pay provision. The lower the gas price, and the more reasonable the levels of take-or-pay, the more likely is the oil company to assume that the buyer will adhere to the terms of the take-or-pay provision.

Gas Plant Expenditures

Although price and deliverability of gas are both important, they are only part of the decision making process linked to investment in the gas processing facilities. The large upfront cash expenditures associated with the gas processing facilities require a rapid payback to improve the discounted cash flow rate of return on the project. Aside from the price for the gas, the key factor becomes gas volumes and the sale of gas liquids.

The private investor (oil company or third party) will carefully review the domestic market for the gas to make sure that the initial regional demand is significant enough so that the gas plant will be fully utilized at its inception and immediately take advantage of economies of scale. The host
country must not assume that a gas plant will be built and financed on the assumption that local demand will increase over time to effectively utilize the processing facilities. Economies of scale are critical to any processing effort with marginal cost falling dramatically as utilization of the gas plant is maximized. Private investment will focus on the marginal cost of delivering the gas to maximize the profit per volume of gas throughput. Again, the key is to improve the cash flow from the project to return the invested capital to the private sources of financing.

Pipelines

The gas plant is linked to the end user by a transmission pipeline system. Many countries already have state owned transmission systems and do not want private systems, so in these countries, private investment in the gas project would stop at this point. However, for those countries without an existing pipeline grid the private investors may defer any expenditures on gas field development and the gas plant until a pipeline is completed or assured of completion. Again, the importance of a completed transmission system is to allow full utilization of the gas processing plant and to speed up the timing of the cash return to the investors.

Separate financing of transmission systems is quite common in the United States and exists in some developing countries. Financing requires long term gas contracts from purchasers to provide assurance as to pipeline utilization and profitability of gas sales. Along these lines a take-or-pay contract will be necessary to attract private financing for the gas producer. To further assure that the transmission system is financed and built, the gas producer may want to take an equity interest in the pipeline and perhaps even build and operate it, either directly or through a consortium or sub-contractor. This type of equity participation would change the economics of the whole project.

Although the transmission pipeline could be a separate entity earning a fixed rate of return for providing transportation-only services, in most developing countries, this is not the case. The transmission pipeline could not stand alone as a profit generating entity. Rather, the profit used to repay the project financing must come from gas sales. Thus, for a developing country, project financing for gas development encompasses both the gas processing plant and the transmission pipeline grid. The two cannot be separated and assurances are needed as to gas demand, initial volumes and long term purchase prices before they will be undertaken.

Improving Payback Through Shifting Ownership

To attract private investment in the building of a gas processing plant, gathering lines and pipeline transmission grid (where approved by the host country) for a domestic gas project, it will be important for the investor to obtain a quick payback. This can be done through a shifting of profit shares during the life of the project.
This type of shifting of net profit interests is quite familiar to oil companies and routine in the drilling of wells under production sharing agreements. It takes the form of cost recovery production where the oil company that discovers and develops an oil field initially takes more than its profit sharing share of the crude produced until it has recovered its costs.

While countries differ as to what percentage of the gross daily recovered crude is attributable to cost recovery oil, and which oil company costs should be recovered before the host government's state oil company backs into the production, the basic concept of cost recovery is not questioned. Oil produced from a field is separated for accounting purposes into cost recovery and profit categories for the oil company (with income taxes levied on the profit oil), and the host country's profit share or royalty oil.

One example as to how the shifting of net profit interests might be effectuated is where a private entity funds 50% of the cost of building a gas plant and pipeline. Instead of receiving 50% of the profit attributed to its ownership interest, there may be a shifting of net profit interest so that the private entity receives a 75% share of the profits until it has recovered its initial investment. At that time its share of the profit will fall to 25% until the other partners have obtained the return of capital. Thereafter, the interests return to their original percentages (i.e. 50% each). This raises the rate of return for the company and imposes an implicit cost to the country through deferral of its profit share.

The advantages to the private investor of this approach are obvious: its money is at risk for a shorter period, the initial rate of return on the investment is raised, and it still participates in rising prices and rising demand over the long term. All this is accomplished at a cost to the other investor in the form of a delay in receipt of profit and absorption of longer term price risk. However, if the host country controls the risk of gas pricing in the future, then it makes sense that the country absorb that risk through deferred receipt of its profit from the venture. This should prove to be an acceptable trade-off for the host country if it enables private project financing.

**Tax Subsidies**

To initiate investment in a local gas project, the cost recovery concept may have to be sweetened by the host country. Direct or indirect taxation of any profit accruing to the private investor from gas sales may have to be foregone until the cost of the gas plant and pipeline costs are recovered by the private investor. In other words, most of the gas sales revenue may have to go to the private investor and remain untaxed by the host country until payback of the risk capital is achieved. This will hold true for any royalties due to the host country if, in fact, a concession rather than a profit sharing agreement is involved.

Likewise, the host country may have to give priority to the private investor for expatriation of his profits. The investor incurs significant currency risk stemming from the fact that the gas sales will not generate foreign currency for the host country and the gas profit will be paid to the
investor in local currency. As noted above, one of the easiest ways to mitigate this currency risk is to allow the company to develop and sell the gas liquids on the export market. Otherwise, in projects without liquids or where another producer has first call on them, the host country may have to provide the gas project's private foreign investor with preference over other foreign companies operating in the country for conversion of local currency to foreign currency, barter goods, or right to the country's share of gas liquids for export. It is worthwhile to note that if the company is also an oil producer in the same country then reinvestment of local currency profit from the gas project could be less of a problem since some oil production costs are incurred in local currency.

While these terms may initially appear to be unfair to the host country, the fact remains that the gas fields may not be developed and the capital expenditures made unless the rate of return and initial cash recovery are acceptable to the investor. Due to the high costs of development, the host country and the private investor do not expect the gas price paid by the local users alone to generate this return. Rather it is the tax and profit sharing provisions within the country's control that may be used to offer the private investor the rate of return he is seeking. The host country will have to defer receiving certain income for a period of time in order to be able to take advantage of this indigenous source of energy.
VI. Conclusion

There is no universal way of attracting oil company investment in the development of natural gas reserves to meet local or regional demand in the developing countries. Each country must review its own level of hydrocarbon sophistication and recognize that the oil companies will analyze the investment opportunity associated with developing a natural gas field accordingly. Countries must recognize that each step of the exploration and development process calls for a different type of incentive to attract private investment in natural gas development. Finally, the host country must expect to forego considerable tax, royalty or profit sharing income from the early year of the gas project until the private investor has received a payback on its initial capital investment. These host country concessions are necessary to attract private investment for the gas project which otherwise would not be made.
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