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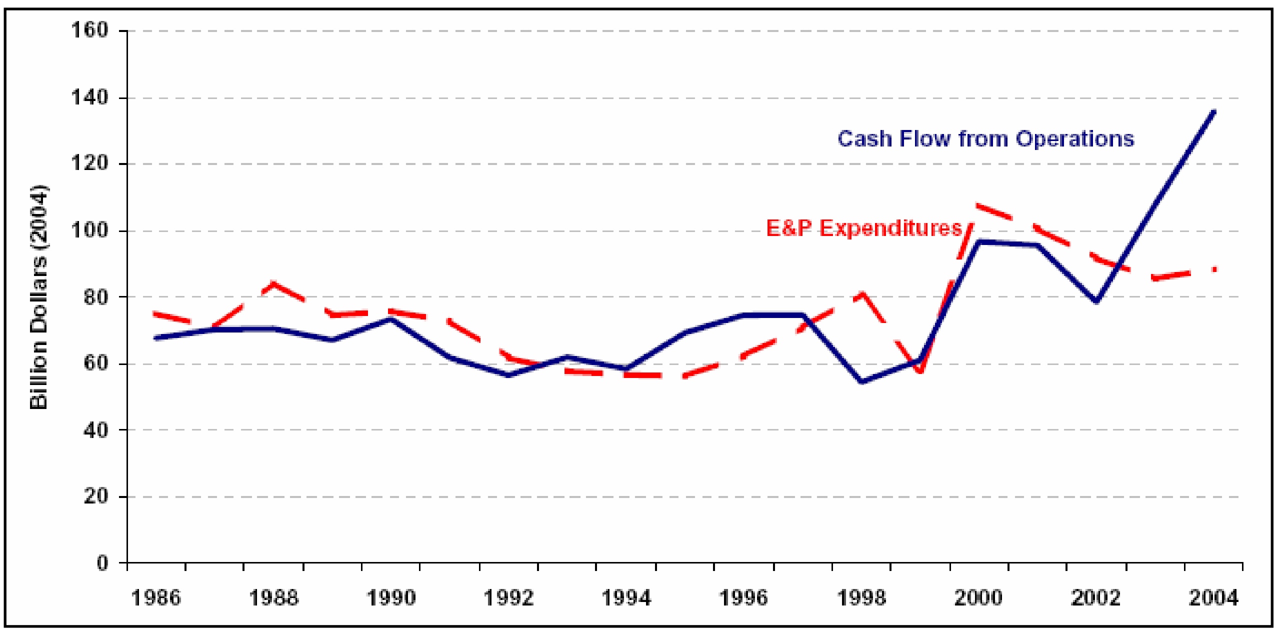
Capital Investment Decisionmaking and Trends: Implications on Petroleum Resource Development in the U.S. Gulf of Mexico



U.S. Department of the Interior
Minerals Management Service
Gulf of Mexico OCS Region

Cooperative Agreement
Coastal Marine Institute
Louisiana State University

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Authors

Mark J. Kaiser
Allan G. Pulsipher

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ABSTRACT

Many factors impact the demand for and supply of oil and natural gas, influence how and where energy companies invest their capital, and determine the manner in which countries compete to attract foreign investment. World oil supply derives from the investment decisions of individual companies, the political decisions of countries in regard to licensing and degree of foreign investment, and a multitude of other variables that influence system dynamics, including price, inventory levels, geopolitics, market psychology and manipulation, OPEC policy, exchange rates, unexpected events, and resource availability.

The purpose of this report is to examine the factors that impact the oil and gas exploration and capital markets. We begin with a general overview of the oil and gas industry and product demand and supply, provide background information on oil and gas resources, and describe the defining characteristics of exploration and capital markets. The factors that impact supply and demand, investment decisions, and country competitiveness are then reviewed. We conclude with a summary outline of the fiscal systems used in the exploration and production industry.

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1. EXECUTIVE SUMMARY

The demand for oil and gas begins at the individual and corporate level. Individuals drive cars, heat and cool their homes, and consume food and other services, all of which require – either directly or indirectly – oil, gas, and petroleum-derived products. Industry provides goods and services that require energy to function.

Many factors impact the demand for and supply of oil and natural gas, influence how and where energy companies invest their capital, and determine the manner in which countries compete to attract foreign investment. The relationship between the various factors and their relative importance is subject to interpretation, argument and debate. World oil supply derives from the investment decisions of individual companies, the political decisions of countries in regard to licensing and degree of foreign investment, and a multitude of exogenous variables that influence system dynamics, including price, inventory levels, geopolitics, market psychology and manipulation, OPEC policy, exchange rates, unexpected events, and resource availability.

The purpose of this report is to examine the factors that impact the oil and gas exploration and capital markets. We begin with a general overview of the oil and gas industry and product demand and supply, provide background information on oil and gas resources, and describe the defining characteristics of exploration and capital markets. The factors that impact supply and demand and investment decisions are then reviewed. We then use this information to relate "conventional expectations" concerning these factors to future investment trends in the Gulf of Mexico. The "conventional expectation" is a subjective characterization by the authors of the perceptions, opinions, and analysis prevailing among those that follow the oil and gas industry. We conclude with a summary outline of the fiscal systems used in the exploration and production industry.

2. INDUSTRY CHARACTERISTICS

2.1. Business Functions

Oil and gas companies may be involved in several different types of functions:

- Exploration, development, and production,
- Transportation,
- Refining,
- Marketing and distribution, and
- Petrochemicals.

The "upstream" segment of the business refers to exploration and production (E&P) activities; refining and marketing is "downstream," and transportation is the "midstream" segment of the business.

Companies which operate in all segments of the industry are fully integrated, while companies that operate in one or more but not all segments are called partially integrated or independents. An independent oil producer, for instance, is primarily involved in only E&P; an independent refiner is involved primarily in refining. The largest integrated oil companies are referred to as majors or supermajors. Various other categorizations are also frequently used, such as international integrated, U.S. integrated, large independents, small independents, etc. based on market capitalization, proved reserves, and related criteria.

2.2. U.S. Upstream

A large number of independent producers and a smaller number of fully integrated companies characterize the U.S. upstream. According to the Energy Information Administration (EIA), in 2001 there were 179 large[1] operators in the United States, which accounted for 84.2% crude oil production; 430 intermediate operators, which accounted for 5.8% production; and 22,519 small operators, which accounted for 10% production.

In the U.S. offshore industry, 319 working interest owners were reported[2] in the Gulf of Mexico at the end of 2003. The vast majority of companies in the Gulf of Mexico are small, independent firms, but just 21 companies hold the majority of production responsible for over 80% of 2003 production (Kaiser and Pulsipher, 2006). The top four producing companies (Shell, Chevron, BP, ExxonMobil) are responsible for over 40% total Gulf of Mexico hydrocarbon production.

[1] The EIA defines large operators as producing a total of 1.5 million barrels or more of crude, 15 billion cubic feet of natural gas, or both; intermediate operators as producing at least 400,000 barrels of oil, 2 billion cubic feet of gas, or both, but less than the large operators; and small operators as producing less than the intermediate operators.

[2] The collection of owners and asset holdings are constantly in flux, and so the data reported represents a "snapshot" of conditions that exist relative to the year 2003.

2.3. U.S. Downstream

The structure of the refining industry has undergone significant change over the past decade. Once led by a half-dozen vertically integrated majors, the industry is now characterized by a handful of super-majors and an array of mid-size and small independents focused on refining and marketing within specific regions and product lines. Independent refiners and marketers are typically only involved in downstream activities. The traditional industry model of refining, based on ownership by vertically integrated oil companies and profitability viewed within the context of a linked supply chain, has been replaced by refineries operated in a stand-alone profit center mode.

Before 1980, nearly all U.S. refineries were held by integrated oil companies, while today, ownership structure is more diverse and concentrated. In 2005, the top three U.S. refiners processed 36% of total crude oil; the top 10 refiners processed 77%; and the top 20 refiners processed 92% (API, 2005). Independents currently own about 64% of U.S. refining capacity versus 51% in 1990. Foreign ownership has risen from 19% of total capacity in 1990 to about 25% in 2005. Royal Dutch Shell, BP, Total, Saudi Aramco, and Petroleos de Venezuela SA are major foreign owners of U.S. refining capacity.

The majority of distillation capacity is currently concentrated in large, integrated companies with multiple refining facilities. Fifty-five firms, ranging in size from 880 barrels per day (BPD) to a combined refinery capacity of 1.8 million BPD comprise the industry (EIA, 2005). About two thirds of firms are small operations producing less than 100,000 BPD and representing about 5% of the total output of petroleum products. Large refiners often manage both large and small refineries, while small operators mainly specialize in asphalt, lubricants, and other niche products. Integrated firms such as ConocoPhillips, ExxonMobil, BP, and Chevron maintain a global portfolio of petroleum assets. Independent companies like Valero and Sunoco focus primarily on domestic refining, although they may also be involved in marketing and other operations. Several joint ventures and partnerships also exist.

2.4. Business Characteristics

The oil and gas industry is characterized by a number of unique conditions:

- High capital intensity,
- High level of risk,
- Complex tradeoffs between capital and operating expenditures,
- Long time span before a return on investment is received,
- Lack of correlation between the magnitude of expenditures and the value of any resulting reserves,
- High level of regulation,
- Complex tax rules,
- World’s largest corporations,
- High level of competition, and
- Complex industry structure.

Oil and gas exploration and development is a high risk, capital intensive business. Finding oil and natural gas throughout most of the world is difficult, costly, and uncertain. The cost of obtaining leases and conducting exploratory work requires an enormous investment before reserves are quantified and economic viability ensured.

The expenditure of millions and sometimes billions of dollars is required for a single project, with no guarantees on the success of the outcome. Investment, in its most basic form, is paying now for the purpose of a reward later. Particularly in oil and gas ventures, however, there are risks of various kinds that need to be considered. Does oil exist in the region? If reserves are found are they smaller than expected or decline faster than geologic conditions suggest? The quality and quantity of the resource is uncertain because it exists deep underground in heterogeneous rock formations, and as a deposit is produced, the cash flows are subject to various forms of uncertainty and risk (Table A.1). Will drilling lead to a blow-out? What is the probability of an earthquake, mudslide, or hurricane destroying the facilities? Will oil prices remain strong or nose-dive? How will inflation rates behave? Will the government try to renegotiate the terms of the contract at a later date? Is nationalization a risk?

Risks arise from the project (construction, operation, production, reserve), as well as changes in global economic conditions (market, macroeconomic), political circumstances (regulatory, expropriation), legal conditions (contract, jurisdictional), and force majeure (natural disaster, civil unrest, terrorism). The higher the risk associated with an investment, the higher the cost of capital and the higher the return required by investors and lenders (Grayson, 1960).

After a well is drilled, the reservoir drive pushing the oil to the surface will progressively exhaust itself if no additional investment is made (Dyke, 1997). To produce at a high rate of extraction requires more wells, greater production and storage facilities, and greater transportation capacity. A complex trade-off exists between producing "fast" (large number of wells, high capital expenditures) or "slow" (fewer wells, low capital expenditures).

The long-lived nature and high capital cost and risk characteristic of E&P projects result in a long payout period, and due to the nature of the resource and project life cycle, there is generally a significant time delay between the magnitude of expenditure and the value of the reserves. This time delay results in significant problems in accounting for oil and gas operations, as well as measuring performance, because there is no direct correlation between the magnitude of expenditures and the value of reserves (Gallun et al., 2001).

The oil and gas industry is large with some of the world's largest corporations. In the U.S., 29 major energy companies in 2004 reported operating revenues of $1.13 trillion, equal to about 15% of the $7.4 trillion in revenues of the Fortune 500 corporations (U.S. Energy Information Administration, 2005).

The structure of the oil and gas industry is dynamic and highly competitive. Majors, independents, and National Oil Companies (NOCs) each have different business models, corporate governance, shareholder expectation, and outlooks of the industry, and all vie for access to resources. Oil and gas companies have a vast intellectual capital, but it has a peculiar limitation, since it has no value unless applied in the exploration and production of oil and gas.

2.5. Industry Structure

2.5.1. Integrated Oil Companies: Major integrated firms such as BP, Chevron, ExxonMobil, Royal Dutch Shell, and Total tend to seek opportunities on a worldwide basis with large upsides to deploy their management, financial, and technical skills. Majors specialize in managing complex, multifaceted and technically challenging ventures, and seek projects that help balance their portfolio of assets. Capital is allocated to areas on a risk-reward basis within the constraints of maintaining a balanced portfolio of projects.

Integrated firms with a geographic specialization are shown in Table A.2 and include U.S. producers (e.g., Amerada Hess, ConocoPhillips, Murphy Oil), Canadian producers (e.g., Husky, Imperial Oil, Suncor), and international firms which do not have a large presence in North America but are active elsewhere throughout the world (e.g., ENI, Lukoil, Petrobras, Petrochina, Statoil).

2.5.2. Independents: Independents seek prospects across a wide range of opportunities: from modest to marginal reserves, high to low risk projects, regional and global locations. Examples of independent companies classified according to size and geographic operation are depicted in Table A.3. Independents usually have lower overhead than majors, can act quickly on strategic opportunities, and tend to have an entrepreneur flair. Independents may seek to grow in reserves or capital, and may transition across categories depending upon their business objectives, merger and acquisition strategies, and other factors.

2.5.3. National Oil Companies: The role of NOCs is arguably the most important factor in the future of the industry. NOCs control the majority of oil and gas reserves known in the world and demand-side NOCs are becoming more active competitors in world markets. A list of selected NOCs is provided in Table A.4.

State-owned companies are generally formed to maximize revenue from state resources. Governments use NOCs for many different national objectives, however, from resource custodian, securer of supply, revenue collector, or engine of national development. National Oil Companies have broader constraints and obligations than private corporations, basing their decisions on domestic, geopolitical, as well as economic factors.

Not all NOCs are created equal. National Oil Companies can be classified in a number of ways, such as in terms of their degree of privatization (state monopolies, partial privatization, full privatization), resource ownership (resource holders [supply-side companies] vs. resource seekers [demand-side companies]), country/business characteristics (GDP per capital, economic strength, corruption index, reserves), strategic priorities (revenue growth, security of supply, profit/margin, local economic development, international/diplomatic relations, infrastructure development), etc. Demand-side NOCs are changing the nature of competition, offering supply-side NOCs strategic partnerships that extend to economic and infrastructure development. The political alignment between nations and their oil companies can bring a distinct competitive advantage, which will further increase competition for multinational companies in acquiring investment opportunities.

In terms of reserves, over 90% of the proved oil reserves in the world are under direct or partial state ownership, primarily in the Middle Eastern OPEC countries. The top 10 oil and gas company rankings by reserves and production for oil (Table A.5) and oil and gas (Table A.6) illustrates the absolute strength of NOCs. PFC Energy estimates that 65% of the world's proven oil and gas reserves are controlled by governments not open to western companies; 16% proven reserves are held by Russian companies; 12% by governments with limited access for investment; and 7% with full access (Ball, 2006).

2.6. Mergers and Acquisitions

Mergers and acquisitions in the oil and gas industry occur for various reasons, generally related to the need for increased efficiency and cost savings (U.S. General Accounting Office, 2004), and increasingly, the need to compete with demand-side NOCs and offer synergies with international partners. Merger and acquisition activity may also be driven by the desire or need to diversify assets, enhance stock values, and respond to price volatility. From 1991-2000, over 2,600 merger transactions occurred in the oil industry (U.S. General Accounting Office, 2004). The vast majority of the mergers (approximately 85% of the total) occurred in the upstream segment, involving one company purchasing an asset from another company, such as a refinery, pipeline, or producing properties. The downstream segment accounted for about 13% of the mergers; the midstream segment about 2%. The majority of the reported transaction values were below $50 million, and over 89% of these mergers were asset transactions. About 32% of the mergers exceeded $50 million and 3% were over $1 billion.

2.7. Corporate Strategies

There are many strategies that a company may pursue in exploration, development, and production activities. The basic strategy that a company adopts, and the factors that drive the selection, provides information on the way companies do business and view the outlook of their industry. Strategies for public companies are frequently disclosed at investor and Board of Director meetings and can be inferred from annual reports, whereas strategies for NOCs may not be articulated or known outside the company. The diversity and depth of strategies that exist in the industry is significant, and no categorization is sufficiently descriptive to encompass all possible cases. Categories may change as internal (staffing, assets, successes, failure, etc.) and external (oil price, markets, interest rates, etc.) circumstances are played out.

For the purposes of discussion, we apply the following classification:

- No specialty,
- Geographic specialty,
- Technological specialty,
- Low cost specialty, and
- Risk specialty.

Companies may specialize within a single category or simultaneously pursue projects that fall within two or more categories. No specialty strategies are commonly carried out by the large integrated companies to help ensure that failure in one or more areas is compensated by success elsewhere. Oil and gas companies that hold geographically diverse assets across all parts of the supply chain are less vulnerable to specific events than companies that hold assets in one part of the supply chain in one geographic region. Breadth of operations allows companies to reduce the volatility of their return on investment and reduce their cost of capital. Integrated oil and gas companies tend to have lower volatility of their return on investment than independent companies.

Geographic specialization allows a company to minimize overhead expense and develop a regional expertise which may lead to reduced drilling and development cost in the region. Each country provides different opportunities for investment which depend on technical, economic, and political factors; the core competencies of the company and their strategic goals; and specific geopolitical and socioeconomic circumstances. One of the downsides of geographic specialization is that it restricts upside potential when reserves begin to decline, but specialization also allows a high degree of learning economies. Most independent operators in the U.S. offshore, Pemex (Mexico), and several NOCs fall within this group.

Technological specialization may take various forms and allow companies to capitalize on in-house technical strengths or to specialize in specific areas such as onshore/offshore, shallow water/deepwater, oil/gas, geologic and working interest plays, and mature assets.

Low cost strategies allow companies to explore without large financial backing and to farm out acreage after adding value to the asset, or to purchase marginal (end-of-life) property for production and acreage opportunities.

Risk strategies involve confining activities to ventures that have a defined risk-reward level. High risk projects are expected to have high rewards, low initial cost, and low government take. Low risk projects are more likely to occur in proven producing areas and will have lower rewards because of less favorable government terms and smaller available prospects.

2.8. Corporate Goals

The three primary objectives of every corporation are to:

- Increase its equity appreciation (total worth) to survive and grow,
- Control the total cash flow within, into, and out of the corporation, and
- Maintain or increase some form of dividends to shareholders.

To accomplish these tasks, the company must receive an average positive rate of return on its portfolio of investments. Since projects and investments appear as cash flows, the control of cash usually has some form of corporate decision rules and procedures (Lerche, 1992). The criteria to give a dividend, repurchase shares, or invest in projects are the capital budgeting decision.

2.9. Capital Budgeting Process

Budgeting is practiced by all public, private, and National Oil Companies, but because of its encompassing nature, a standardized definition does not exist. A budget is usually considered the principal management vehicle for the expression of a company's plans and objectives for a specified period of time (normally twelve months).

A capital budget is a fixed asset spending plan which in the oil industry tend to occur on a project-by-project basis. A profitable[3] oil company is the combination of profitable projects, and since each project has a different risk-reward strategy, oil companies try to build a diversified portfolio to maximize the return to their shareholders.

The typical capital budgeting process follows three steps:

1. Identify all non-discretionary (mandatory) capital expenditures; e.g., new government regulations, corporate policy, previously initiated projects.
2. Establish the level of funds available for discretionary expenditure.
3. Select investments in descending order of rank until either the total available funds are exhausted or the minimum acceptable yard stick value reached.

Each step will vary from one organization to another with various techniques and criteria employed in ranking investment opportunities. Large organizations tend to rank investments using different criteria and emphasis than smaller companies. The volume and quality of investment opportunities, and the immediate cash position of the organization, also impact the way the rankings are perceived and ranked.

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[3] The Royal Dutch Shell statement of general business principles is standard:

> *"Profitability ... is essential for the proper allocation of corporate resources and necessary to support the continuing investment required to develop and produce future energy supplies… The criteria for investment decisions are essentially economic, but also take into account social and environmental considerations and an appraisal of the security of the investment."*

The criteria that are typically used in ranking investment opportunities include payback, net present value, discounted return on investment, internal rate of return, and profit on investment (Wehrung, 1989). The investment opportunities are graded according to the criteria which reflects the goals and strategies of the organization.

3. PRODUCT DEMAND AND SUPPLY

Over the past two decades, the demand for petroleum products in the U.S. has risen steadily, due in part to a growing population, falling fuels prices, Americans' preference for heavier and more powerful vehicles, and an increase in passenger and goods travels. In 2005, daily demand for refined products in the U.S. was about 21 million barrels, equivalent to a consumption rate of about 20 pounds of petroleum per person per day. No other commodity in the history of the world has ever been consumed at such levels.

In 2005, the U.S. consumed about 14 million barrels per day (BPD) in the transportation sector, 4 million BPD in the industrial sector, 2 million BPD in the residential and commercial sector, and 1 million BPD in the electric power sector (Figure A.1). Consumption trends by sector for refined products are shown in Figure A.2-A.5.

The U.S. demand for crude oil and petroleum products exceeds its supply (Figure A.6), and so the U.S. imports a variety of intermediate and final petroleum products in addition to crude oil. About 60% of the U.S. petroleum requirements are currently imported, and although the U.S. is still one of the world's largest producers of crude oil, its reserves base is only 3% of the world's proven reserves (British Petroleum, 2005). For the foreseeable future, the U.S. will grow increasingly dependent on imported oil for its needs.

The raw materials and intermediate materials processed at refineries in the U.S. are depicted in Figure A.7. Refinery output is the total amount of petroleum products produced (Figure A.8). About 90% of crude oil in the U.S. is converted to fuel products that include gasoline, distillate fuel oil (diesel fuel, home heating oil, industrial fuel), jet fuels (kerosene and naphtha types), residual fuel oil (bunker fuel, boiler fuel), liquefied petroleum gases (propane, ethane, butane), coke, and kerosene (Table A.7). Nonfuel products such as asphalt, road oil, lubricants, solvents, waxes and nonfuel coke, and petrochemicals and petrochemical feedstocks such as naphtha, ethane, propane, butane, ethylene, propylene, butylene, benzene, toluene and xylene, comprise the remaining crude conversions.

4. OIL AND GAS RESOURCES

4.1. Fossil Fuels

Fossil fuels consist of plant and animal remains (organic matter) that have been preserved in rocks. Organic material accumulated in swamp beds and on the bottom of ancient seas hundreds of millions of years ago, and through sediments of sand and mud and conditions of high temperature and pressure, a variety of solid, liquid, and gas hydrocarbon molecules were created, such as coal, oil, natural gas, tar sands, and oil shale. Since the distribution of swamps and ancient seabeds conducive to fossil fuel formation is a function of Earth's plate tectonic and climatic history, fossil fuels are not expected to be evenly distributed in the world.

4.1.1. Coal: Coal is formed from vegetation which grew in swamps hundreds of millions of years ago. Peat deposits were built up as vegetation died and accumulated at the bottom of swamps to form spongy, brown material, called peat. Geological forces buried the peat under the surface of the earth, where the layers were compacted by pressure and heat, causing it to release water and other gases in a process referred to as coalification (Schobert, 2002). Coal formed from the compressed peat. The greater the heat and pressure, the harder the coal; the harder the coal, the less moisture it contains and the more efficient it is as fuel. As coalification proceeds, coal increases in rank from lignite, to bituminous, and to anthracite, increasing in value, heat content, and quality. Lignite is the softest coal and contains the most moisture. Sub-bituminous and bituminous coal are medium-soft and medium-hard coal with less moisture and higher heat value. Anthracite is the hardest coal with the highest heat content and value per ton mined.

The most important factors affecting coal quality are ash, sulfur, and trace elements. Ash is the residue that remains after burning and consists of clay minerals and quartz. Sulfur occurs in various forms and low-sulfur coal is considered to contain less than 1.5% sulfur by weight.

Coal reserves are easy to find and document, and because sedimentary basins are widespread throughout the world and the process to form coal is relatively simple, coal is the most abundant fossil fuel in the world. Coal beds tend to occur close to the surface of the earth, usually within a few hundred feet of the surface.

4.1.2. Crude Oil and Natural Gas: Crude oil and natural gas are derived from fats and other lipids in marine algae and other aquatic plants that were buried with sediment. The organic matter transforms into kerogen, an insoluble material that consists of molecules much larger than those in oil or gas. With burial, pressure and temperature increases and kerogen decomposes to form crude oil and natural gas (Kesler, 1994).

Crude oils are a complex mixture of hydrocarbon molecules of many different sizes and shapes. Each crude oil produced in the world has a unique chemical composition containing distillates of different molecular composition, burning qualities, and impurities such as metals, asphaltenes, nitrogen, and sulfur (Speight, 1991). The main characteristics used to classify hydrocarbons include molecular composition, specific gravity (density), viscosity, color, and other physical properties. Crude oil is a liquid, and because of its chemical composition, is a very compact source of energy that is easily transported.

Natural gas is a mixture of hydrocarbon gases, carbon dioxide, and nitrogen. Methane (CH_4) is the major constituent, followed by ethane (C_2H_6), propane (C_3H_8), butane (C_4H_{10}), and higher components in smaller fractions. If oil is found in association with crude oil, it will have a higher percentage of heavier components which are more valuable than methane, not only because they have a higher heat content but because they are a valuable refinery feedstock. Gas found in association with coal is referred to as coalbed methane. Dry natural gas consists primarily of methane and ethane.

For an oil or gas field to exist, the geology of the area must have been conducive at some point in time to the formation of oil or gas and its storage. Four conditions are generally required (Levorsen, 1967): (1) there must be source rocks in which the hydrocarbon was generated; (2) this generation process must have reached, but not exceeded, maturity; (3) there must be separate subsurface reservoir traps enclosed by impermeable structures that prevent oil from escaping and dissipating into the surroundings; and (4) for a commercially viable field, the traps must be sufficiently large, either in extent or depth, or both, to hold enough hydrocarbon to make the cost of establishing a production facility and market delivery system economic.

Oil and natural gas are formed under significantly more restrictive geologic conditions than coal (requiring, “oil windows” and “structural traps” to ensure their creation) in deposits that lie thousands of feet beneath the ground over regions that are hostile or where access may be limited. Oil and gas reservoirs lie beneath both dry land as well as offshore under the oceans.

4.2. Market Value

The value of crude oil derives from the products which are produced in a refinery. During most of the twentieth century, the oil industry has focused on supplying gasoline, the highest valued of the refined products of crude oil. The demand for oil has thus come mainly from the gasoline (automobile) market, which continues to increase incrementally, by a few percent per year as populations and economies grow. Supply, on the other hand, tends to increase in discrete amounts in response to periods of high E&P activity driven by high prices and as major projects come on-line.

The market value of crude oil depends primarily on its density and sulfur content. The density of oil is related to the relative yields of production that can be extracted during the refining process. Sulfur content is important because energy must be spent in refining to remove the sulfur to meet product specifications. Heavy, sour crude sells at a significant discount to light, sweet crude since it can only be converted in high complexity refineries with coking, catalytic cracking, and hydrocracking capacity (National Petroleum Council, 2004).

Natural gas is used as a feedstock for petrochemical facilities, by utilities to generate electricity, and by residential and commercial establishments for heating. The demand for natural gas is seasonal for residential consumers and electric utilities. Industrial and commercial demand tends to cycle with the general business environment (U.S. General Accounting Office, 2002; U.S. General Accounting Office, 2006).

4.3. Reserves and Resource Estimates

Oil and gas resources are classified according to proved, probable, and possible categories in the U.S. and proven and possible categories in the U.K. (Gallun et al., 2001). Companies operating outside the U.S. and U.K., National Oil Companies, and private firms employ these and other guidelines in reserves estimation. Reporting conventions vary by country, and often do not comply with the strict definitions required for company reporting by the U.S. Securities and Exchange Commission (SEC).

Proved reserves are estimates of the amount of oil or gas (coal, or other resource) which can be recovered economically using current technologies. Proved reserves is the most certain because it includes only those resources that have already been delineated and developed and shown to be economically recoverable using existing technology under prevailing market conditions.

Proved reserves have a high probability of eventual recovery, often interpreted as the 10% fractile of the distribution of recoverable resource; i.e., based on current knowledge there is believed to be a 90% chance (P90) of ultimate recovery exceeding this amount. Probable and possible reserves are further removed from having been tested by the drill bit, and thus, are subject to increasing margins of error. Probable and possible reserves are often referred to as P50 and P10, with probable reserves using a longer-term price assumption and more advanced technology to estimate underground stores.

Companies do not normally evaluate project economics based on proven reserves, because this is a conservative estimate of resource potential that may not achieve the project hurdle rate. Instead, companies apply the less conservative proven and probable category, and would prefer that the SEC change its reporting requirements to reflect this distinction (LeVine, 2006). Other industry observers (e.g., Simmons, 2005) feel that the SEC should make reserves reporting satisfy more stringent conditions than the current proved reserves definition.

The reserves estimates used by the U.S. oil and gas industry are considered fairly reliable, since no one is better prepared to understand the geologic conditions and estimate the costs of extraction, transportation, etc. than the companies whose business is to make a profit and stay in operation. Firms may at times distort or conceal data, but for the most part, companies require access to reliable information to make good business decisions, and this is reflected in their reserves reporting (Peirce, 2000).

4.4. World Proved and Undiscovered Reserves

A number of primary and secondary sources report oil and gas reserves and resources. Primary sources mostly include company and government data, while secondary sources such as *World Oil*, *Oil and Gas Journal*, *BP Statistical Review of World Energy*, *Agip World Energy Outlook*, and Cedigaz compile data from primary sources without review. Various commercial data sources are also available that collect and analyze reserve estimates on a field-by-field basis. All reserves values are estimates, and so one can expect wide variation among the different reported sources.

The United States Geological Survey (USGS) and Minerals Management Service (MMS) publish periodic undiscovered resource estimates for the world and U.S. Outer Continental Shelf (OCS) based on geologic information, probabilities of past discoveries, economic conditions, and various other factors. USGS estimates a probability distribution for world resources at the 5% (P5), 50% (P50), and 95% (P95) level. Because of the nature of the resource, the uncertainty associated with undiscovered estimates can be considered at least an order-of-magnitude higher than the proven or probable reserves category.

The MMS recently completed an appraisal of the technically recoverable oil and gas resources for the U.S. OCS. Estimate of undiscovered recoverable resources are presented in two categories: undiscovered technically recoverable resources (UTRR) and undiscovered economically recoverable resources (UERR). UTRR estimates are presented at 95th and 5th percentile levels, as well as the mean estimate (Table A.8). This range of estimates corresponds to a 95% probability and a 5% probability of there being more than those amounts present, respectively. The 95% and 5% probabilities are considered reasonable minimum and maximum values, and the mean is the average or expected values (U.S. Department of the Interior, Minerals Management Service, 2006).

Estimates of UTRR for the entire OCS range from 66.6 Bbbl at the F95 fractile to 115.1 Bbbl at the F5 fractile with a mean of 85.9 Bbbl. Similarly, gas estimates range from 326.4 to 565.9 Tcf with a mean of 419.9 Tcf. On a barrel of oil-equivalence (BOE) basis 54% of the potential is located within the Gulf of Mexico. The Alaska OCS ranks second with 31 percent. The Pacific is third among the regions in terms of oil potential and fourth with respect to gas.

At the end of 2004, world hydrocarbon reserves amounted to 1.3 trillion barrels of oil, 6,112 trillion cubic feet of gas, and 1.08 trillion tons of coal (Table A.9). Proven and undiscovered oil and gas on a regional (Table A.10) and country basis (Tables A.10-A.13) indicate geographic distribution. Proven oil reserves are concentrated in the Middle East, while gas reserves appear to be more abundant than oil and also more uniformly distributed. The largest gas reserves are in Russia, Iran, and Qatar.

4.5. Unconventional Resources

Unconventional resources are an umbrella term for resources that are more challenging to extract than conventional resources. Under the right economic and technological conditions, however, unconventional resources are expected to add significantly to future oil and gas supplies. Today, two “unconventional” oil resources are being produced – heavy oil from Venezuela’s Orinoco oil belt and bitumen from Canada’s tar sands. Unconventional resources also include oil shale, coal bed methane, gas hydrates, and tight gas. Coal bed methane and tight gas are also under active production. Most of the world’s known unconventional resources are found in the Western Hemisphere, in the U.S., Canada, and South America.

Unconventional resource estimates typically represent the total resource in place and do not guarantee economic feasibility, and so reserve estimates are more uncertain than conventional resources and should not be compared directly.

4.5.1. Heavy Oil: Heavy oil is oil that will flow under normal reservoir conditions but requires Enhanced Oil Recovery (EOR) techniques for economic production. Heavy oil is typically easier to locate than light-crude pools and occur closer to the surface, but the oil is more difficult and costly to extract, transport, and process. Venezuelan extra-heavy crude is nearly as dense as, or denser than, water and significantly more viscous than conventional crude. Heavy oil deposits are found throughout the world, but the most significant developments are presently confined to Canadian oil sands and the Orinoco belt in Venezuela. The USGS estimates that there are 434 billion barrels of technically recoverable heavy oil throughout the world (Table A.15).

4.5.2. Tar Sands (Bitumen): Oil that will not flow is referred to as tar (or bitumen). Tar can be found in all types of rocks, but tar in sandstones is referred to as tar sands. Tar sands are mined and then mixed with hot water or steam to extract the bitumen, and is then processed in secondary conversion facilities to convert to a material like oil, called syncrude. Most tar stands are currently extracted by strip mining, or by heating or solvating underground deposits and pumping out the resulting oil (in-situ production). Because the majority of bitumen resources are not surface accessible, in-situ production will likely overtake strip mining as operations advance.

There is no exploration risk in tar sands production, and for that matter, no decline curve, but the operation is sensitive to natural gas prices and must have access to sufficient water sources. Large deposits of tar sand are found in the Athabasca area of Alberta, and Canadian and international oil companies are reported to be prepared to spend $87 billion in oil sand development over the next 10 years (Carlisle, 2006). World resource estimates for bitumen are shown in Table A.15.

4.5.3. Oil Shale (Kerogen): Oil shale is shale from which oil can be obtained by processing. Shale oil is mined, crushed, and heated to temperature of 500-1,000°C in a process called retorting. A large quantity of water, anywhere from 2 to 5 times as large as the volume of oil produced, is required in the process. The shale undergoes pyrolsis which releases hydrocarbon gases and liquids. In the 1980s, $5 billion was invested in the U.S. in oil shale projects, but difficult engineering and unexpected economics made all the operations commercial failures. Today, oil shales are not currently economically recoverable, but high oil prices are again reviving interest in this potential resource. The worldwide oil shale resource base is estimated to be 2.6 trillion bbl located across 26 countries (Johnson et al., 2004a and b). The United States is the world leader in oil shale resources with about 2 trillion bbl. The most economically attractive U.S. deposits, containing an estimated 1.5 trillion bbl, are found in the Green River Formation in Colorado, Utah, and Wyoming.

5. OIL AND GAS MARKETS

5.1. Oil and Gas Are Commodities

Oil, gas, and the products of refining – gasoline (aviation and motor gasoline and light distillates), middle distillates (jet fuel, heating kerosene), fuel oil, and other products (refining gas, lubricants, wax, solvents, refinery fuels) – are commodities. Commodities are products that are undifferentiated from a competitor and sold on the basis of price, defined in competitive markets by the intersection of supply and demand curves at a given location and time, and influenced by other factors. Although oil and gas are commodities, oil and gas markets have many unique features.

5.2. Prices Are Determined by Supply, Demand, and Inventory Conditions

Spot prices are determined by supply, demand, and inventory conditions at a given location and time. The most fundamental economic relationship governing commodities is that quantity demanded is a function of price. Demand for commodities is generally inelastic, and inventories – when they exist in sufficient volumes – allow supply and demand to achieve a quasi-equilibrium which acts to smooth out spot prices and reduce volatility. Supply is defined by production and inventory, and for energy commodities, underground reserves. Balancing supply and demand occurs at both the regional and world level. Prices reflect the combined influence of all market information, including expectations of future supply and demand, seasonal factors, inventory levels, market psychology, etc.

The major upheavals of the world and actions taken by governments over the past 30 years can be read in the price history of oil (Figure A.9). Events such as the Asian financial crises, the 9/11 attacks in the U.S. or the recession of 2001 can all be read from historical records. In recent years, global oil demand growth has been high at a time when OPEC has little spare oil production capacity. The tight supply/demand balance has been exacerbated by market concerns about increased geopolitical supply risk in several oil-producing countries. Oil is a global, fungible commodity, and a change in the supply or demand of oil anywhere in the world will affect price everywhere.

The oil industry has experienced greater periods of growth and restraint than the gas industry because historically, oil has been more of an international commodity than gas. The price of oil also influence to varying degree the prices of all refined products (Figure A.10) and primary fuels (natural gas, liquefied natural gas, coal).

5.3. Crude Prices Exist in Many Forms

5.3.1. Benchmarks: The industry has developed a number of reference benchmarks for physical and derivative trading (Geman, 2005). West Texas Intermediate, Brent, and Dubai are three of the major benchmarks for oil. The price of oil is usually more volatile than the differentials caused by the oil quality, and so the prices of other grades of crude oil can be compared against the benchmarks and adjusted for quality.

5.3.2. In-Situ vs. Wellhead Prices: The price of a barrel of oil at the wellhead differs from the value of a barrel of oil in the ground because the reserve must be produced and delivered before being sold to a buyer. Production, depreciation, and transportation expenses account for the majority of the price difference. Over the past decade, oil and gas reserves have sold on average at about 22% and 36% of their respective wellhead prices (Adelman and Watkins, 2003; Smith, 2004). In-situ values are also more stable than wellhead prices.

5.3.3. Spot Prices: Spot prices are wholesale prices for physical delivery at a specific transfer point such as a pipeline or at a harbor. Oil spot markets are prevalent worldwide. Gas spot markets are only common in countries where the gas industry has been deregulated, such as the U.S., U.K., Netherlands, and Norway.

The price of natural gas is determined on a regional basis, and so it is not possible to refer to a "world price" for natural gas. In North America, for example, prices respond to demand and supply forces, while in Russia, the state gas company Gazprom holds a monopoly position. In Western Europe and Japan, the sales price for natural gas is based on competition with alternative fuels and indexed on oil product prices. Most of the gas that is traded internationally is in the form of liquefied natural gas (LNG) long-term supply contracts to finance the expensive infrastructure.

5.4. Oil Supply and Demand Imbalance

The main exporters of crude oil are Saudi Arabia (8.8 Mb/d), Russia (6.7 Mb/d), Norway (2.9 Mb/d), Nigeria (2.5 Mb/d), Iran (2.5 Mb/d), and Venezuela (2.4 Mb/d). The main consumers are the U.S. (20.5 Mb/d), Western Europe (14.8 Mb/d), China (6.7 Mb/d), and Japan (5.5 Mb/d). Geographical imbalances between supply and demand create the need for massive exports from the Middle East, the former Soviet Union, and West Africa to the Far East, North America, and Western Europe. In Table A.16, production and consumption statistics provide a "snapshot" of the imbalance that existed in 2004 between the net importers and exporters of oil.

5.5. Oil Markets Are Global, Gas Markets Are Regional

Crude oil markets are fluid, global, and volatile, and have evolved into the most complex commodity market in existence today, with an interlocking set of physical and financial instruments (Geman, 2005). It costs just a few dollars ($2-3) to transport a barrel of oil across the world – a small percentage of the price of a barrel – which explains why oil is a global market. If consumption increases in one part of the world or supply disrupted in another part of the world, then demand and price signals will transmit the information. Consuming nations cannot insulate themselves from the forces driving the world market, except perhaps by cutting domestic consumption to the level of domestic production. A supply disruption occurs when demand exceeds supply at a specific location and time. Supply disruption can never be completely eliminated because there are many factors that influence supply adequacy, including growth patterns, crude oil imports, seasonal fluctuations, weather patterns, political events, etc.

The cost to transport gas over large distances is significantly more expensive[4] than oil, explaining why gas is fragmented into regional markets (Tussing and Tippee, 1995). Three regional markets in gas currently exist: United States – Canada, Western Europe – (Norway, Russia, Algeria), and Japan – (Indonesia, Australia, Middle East). LNG promises to globalize the natural gas industry, but this is still many years away.

5.6. Oil and Gas Prices Are Volatile

Crude oil and gas prices are more volatile than other commodities, reflecting political and economic events, demand, perceptions about resource availability, and many other factors (Pirog, 2005a). The volatility of the oil and gas industry usually makes the timing of policies ineffective, since the system will change before the policies can take effect (U.S. General Accounting Office, 2006). Regions of the world react differently to crude price variations, depending on the level of taxation, demand elasticity, government support, and many other factors.

5.7. Price Spikes

Oil and gas prices are heavily influenced by major system discontinuities, such as war, regional financial crisis, and political intervention. Because of the balance between oil supply and demand, taking even a small amount of oil off the market can cause prices to rise dramatically. Geopolitical problems have always affected the oil industry, but these problems occurred when surplus capacity could offset disruptions in output from one or more regions.

In late 2002, striking workers in Venezuela, followed by continuing disruptions in Nigeria and the U.S.-led invasion of Iraq took several million barrels out of the supply mix. So when Iran threatens to cut off supply in their standoff with the U.S. or as Russia continues to make foreign investment in their energy sector more difficult, the market has a large risk premium embedded in the price of oil.

There are interesting geopolitical implications associated with the price volatility, since rebel groups in Nigeria and countries such as Chad can threaten to disrupt oil supply to gain political support or leverage for their cause (Cummins, 2006).

In Oil Shockwave, it was estimated that a 4% global shortfall in daily supply would result in a 177% increase in the price of oil (from $58 to $166 per barrel). There have been four oil price shocks[5] since the nationalizations in the early 1970s, and the number and magnitude of price up-ticks has increased since 1997 (National Petroleum Council, 2004).

The economic recessions in the United States are often blamed on oil price increases (Hamilton, 1983). Much research has examined the relationship between oil price movements and their effects on macroeconomic activity, and although the findings are

[4] On an energy equivalent basis, the cost of gas transportation is about 5-10 times higher than oil.
[5] A price spike is defined to be a monthly price increase in crude oil in excess of 10% above the prior year.

widely inconsistent, most studies tend to demonstrate measurable relationships between oil price shocks and aggregate economic activity.

6. DATA SOURCES, DATA QUALITY, AND PROBLEMS OF INTERPRETATION

6.1. Data Sources

Energy is central to U.S. economic activity and prosperity, and so there is a wealth of public data at an exceptional level of detail across all segments of the industry. The quality, accuracy, and quantity of the data are superior to any other industry, anywhere in the world, but significant analytical difficulties are involved in assessment. The reliability and accuracy of data is sometimes difficult to assess, especially when comparing survey instruments and data that are unobservable or proprietary. The industry is fragmented and complex, and carefully designed studies are required to gain insight into each sector. Data requirements vary depending upon the questions to be addressed, the framework applied, and the complexity of the phenomena.

A wide range of data sources are available, including government organizations (USGS, EIA), international organizations (IEA, OPEC, IFP), private and national oil companies, commercial services (IHS, Wood MacKenzie, ODS-Petrodata), and the trade and academic press. All sources are useful, and each has their advantages and disadvantages.

6.2. Data Quality

Data quality varies with the nature of the study under investigation. Field studies which require production, quality, and price data are usually easy to assemble and analyze, while relevant cost statistics are usually more difficult to gather and collect because of proprietary concerns.

Uncertainty about oil reserves and resources varies throughout the world. In the Middle East, reserves data may not change for years, and at other times, fluctuate widely. Reserves in OPEC countries are often considered exaggerated because of cartel polices and are often criticized for being either under- or over-reported. For example, several OPEC countries significantly increased their estimates of proved reserves in the late 1980s even though little exploration or appraisal drilling took place at the time (Simmons, 2005). Estimates remain opaque because of a lack of credible external auditing of national claims.

The manner in which public companies report their expenditures, reserves, and account for cost is highly variable. In the U.S., two accounting methods are generally practiced – successful efforts and full cost accounting – with majors and large independents tending to favor successful effort methods, and smaller independents favoring full cost methods (Gallun et al., 2001). Outside the U.S. accounting practices diverge widely.

A number of investment banks, government agencies, consultancies, and trade publications survey the oil and gas industry to gauge their E&P budget plans and to assess their view of the industry. The coverage of the surveys varies with the organization, and the results are generally not directly comparable across instruments, firms or time due to the nature of the data collection. Spending surveys and cash flow are difficult to assemble on a county-by-country basis, and are usually only available on a regional or global level with a high level of noise due to the survey methodology (survey vs. public records), coverage (sample size), instrument specifications (aggregation, categorization, etc.), and other factors.

Public records can be used to review a company portfolio of assets and the manner in which capital is allocated across business sectors as a function of time. Public information does not include the risk-reward profile of projects, however, corporate risk profiles, or risk-adjusted[6] discount rates.

6.3. Problems of Interpretation

The oil and gas industry is far too complex and dynamic for simple cause and effect relationships to be developed. The most useful perspective is often a description of what has actually happened, rather than the development of complex theory, which due to tractability issues, simplifying assumptions of behavior or system discontinuities, will often leave the analysis unrealistic (Stevens, 2001 and 2002). Descriptions of what has actually happened, however, are often subject to the experience, qualifications, and bias of the analyst, and may provide little or no insight into the structure or drivers of a particular issue. It is for this reason that a balance must be achieved between empirical models and mere descriptions of events. Analysts rely upon aggregated and observable data to draw inferences and make conclusions, but the process of aggregation and the link between data and behavior is often tenuous or ambiguous to render a model useful.

6.3.1. Microeconomic vs. Macroeconomic Perspective: The microeconomic model of behavior which governs an individual firm does not easily generalize to macroeconomic models which relate to the aggregate (regional, global) industry. Some descriptor variables may overlap, but for the most part, the factors will vary significantly. World E&P capital spending, for example, is composed of the expenditures of all industry participants – majors, independents, and NOCs – throughout the world. NOC data is unobservable. Aggregate expenditures vary across time and are likely to be at least partially explained by demand and price variables, as well as factors such as spare capacity and non-OPEC production. These same factors, however, are not likely to be useful to predict firm behavior, which would use cash flow, profitability (return on capital), strategic opportunity, or expected future outlook to guide business investment. The issue to be examined thus dictates the categories employed and the factors selected in model construction.

6.3.2. Aggregation: Data may be aggregated in a number of ways, due to the source of the data or the preferences of the analyst. Aggregation is a useful way to deal with uncertainties or the impact of variables that cannot be modeled, but the process of aggregation necessarily destroys the information content of the data. In capital

[6] Companies tend to focus on technical or country risk assessments to risk-adjust cash flows or discount rates in project evaluation. The assessments are conducted by different corporate divisions or by external advisors; e.g., (Aven, 2004; Wood, 2003).

expenditure surveys, for example, segments of the business are typically presented according to upstream and downstream sectors and decomposed along a company, country, region, or world basis. If any one sector (e.g., exploration and production) is analyzed in isolation from other business activities, the system will probably be misspecified. Oil and gas streams are frequently combined in terms of a BOE-basis, which will introduce additional uncertainty, since oil and gas streams are not identical on a heat-equivalent basis and have been valued quite differently over time. Aggregation generally "smoothes out" uncertainties, but the process may lead to misspecification or bias, or both (Lynch, 2002). Finding costs and reserve replacement ratios, for instance, are particularly poor metrics when computed on an aggregate basis.

6.3.3. Omitted Variables: System behavior and trends are explained through measurable/observable factors, which imply a correlative relationship and predictive ability, but relations may be spurious due to omitted variables. The factors that affect demand and supply, capital investment and country competitiveness are determined by economic principles and commonly accepted industry notions, but there is no general analytic framework that can accommodate all the potential interacting factors. Individuals will likely disagree on specific factors, their specification, relative importance, level of aggregation, and causality. Since there are so many potential factors, it is unlikely that a factor set will suffice in explaining all aspects observed.

6.3.4. Factor Types: Factors may be observable or unobservable, deterministic or stochastic, one- or *n*-dimensional, time varying, cyclic, or fixed. Economic fundamentals or intuition may suggest a possible direction for each factor under consideration, when other factors are held constant (or equal), but unfortunately, "other factors" are rarely equal and the interaction of effects may be beyond modeling capability. Factors may create pressures in one direction for one period of time, the opposite direction for another period of time, and remain ambiguous over a third time horizon. Relationships that are derived based upon a given set of structural assumptions are usually not valid during periods of high factor volatility or when the system structure changes. System structure is itself an artificial construct of our imagination and thus a subjective and ambiguous concept.

7. FACTORS THAT IMPACT SUPPLY AND DEMAND

The supply of oil in the world at any point in time is the sum of the production levels achieved by the collection of many private, public, and state-owned companies. Each individual producer plans for and decides on its own supply level independently, with the exception of OPEC members, and possibly, short-term "alliances" that may form during exceptional times; e.g., extreme price levels, military activity, etc. For the members of OPEC, the level of supply results from the coordination and collective decisions of the member nations. The goals, strategies, and behavior of private and public companies vary widely, but investment decisions for companies tend to be based on profitability criteria, the companies' cash flow position, and its outlook for the future. International oil companies have shareholders who require a return on their investment. The goals, strategies, and behavior of state-owned companies on the other hand are much more diverse. National oil companies have domestic social and political obligations, the need to create foreign exchange, and the desire to exert geopolitical influence.

The demand for oil and gas begins at the individual and corporate level. Individuals drive cars; heat and cool their homes, and consume food and other services, all of which require – either directly or indirectly – oil, gas, and petroleum products. Corporations provide goods and services which also require energy. Aggregating the individual, commercial, and industrial demands of a nation comprise the demand function for the country.

7.1. Economic Activity

Energy availability and consumption play a key role in the process of economic growth, and conversely, is an essential input into technological advancement in the substitution of machines and other forms of capital for human labor. Energy use is a necessary input to economic growth and is also a function of growth.

Energy use is associated with population growth, the expansion of urban centers, industrialization, and the development of infrastructure such as roads and transportation networks (Chima, 2005). It takes energy to produce things of value, and thus, there is typically a strong correlation between a country's energy consumption and economic activity as measured by gross domestic product[7] (GDP). The nature of the relationship is dynamic and will change over time with technological progress and the demand requirements of the industrial, commercial, and residential segments of the nation (Mory, 1993).

In the U.S., economic growth is linked to high levels of oil, natural gas, and electricity consumption, but a feedback mechanism provided by the market generally limits the impact. As GDP growth rates and demand increase, price will also tend to increase, which may lead to more restrictive monetary policies and/or a consumer reaction, both of

[7] The GDP is a measure of the total market value, expressed in dollars, of all final goods and services produced within a nation in one year.

which will potentially slow the rate of GDP growth and limit energy consumption (Pirog, 2005a). In China, these same forces are at play as expanding exports increase the industrial demand for oil, and rising consumer income has increased consumers' demand for gasoline. For countries whose oil exporting sector is a major component of their GDP (e.g., Russia, Nigeria, Saudi Arabia), the expansion of the oil sector is itself likely to lead the growth in GDP[8].

7.2. Inventory

The expectation that oil and refined product inventories influence prices is based on the assumption that prices reflect the current supply/demand balance, and that inventories provide a measure (albeit imperfect) of the changing balance between supply and demand (National Petroleum Council, 2004). Any factor that serves as a measure of the short-term supply/demand balance would be expected to influence prices, but the impact will vary depending on the market perception of the importance of the factor, how fast the information flows to the market, and other conditions at the time of observation. An NPC study found only a modest correlation between inventory levels and crude oil price (National Petroleum Council, 2004). The U.S. Department of Energy (DOE) found a slightly stronger relationship when total crude and product inventories, recent inventory trends (lag terms), and relative inventories measured by actual inventories versus "normal" inventories defined by seasonal trends were included (Ye et al., 2003). A relationship between inventories and the shape of the forward price curve exists, with inventories positively correlated with the forward price spread.

7.3. Price

Price is by far the most accessible and reliable data series available, and thus, is a preferred explanatory variable for supply and demand forecasting. Crude oil price is determined in the world market and depends mainly on the balance between world demand and supply. Markets respond to supply/demand changes with price movements that provide the incentive to increase or decrease supply to correct imbalances (Adelman, 1993; Seba, 2000). High prices lead to increases in exploration and development budgets, and as new oil and gas is found and brought to the market, supply increases and prices are typically reduced. High prices can also make alternative fuels more competitive, potentially reducing demand, and are likely to encourage conservation, further reducing demand.

7.4. Geopolitics

Geopolitical shifts and foreign policies play an important role in global energy security and long-term energy supplies. The fall of communism and the liberalization of

[8] For countries where oil and gas comprise a large part of total export revenue, economic downturns are more likely when oil markets shift. It has been observed that countries with significant oil reserves often end up with low growth rates because they are less willing to adopt restructuring and can afford to shun foreign investment and basic economic criteria in decision making (International Monetary Fund, 2004; Karl, 1997).

economies in Asia and South America have opened vast energy resources previously inaccessible or underdeveloped, while China and India's growing concern about the rising cost of energy and their dependence on import oil has prompted their state-owned companies to aggressively seek acreage and investment opportunity throughout the world, often through aggressive bidding and in regions with high political risk. China's demand for steady supplies of oil is reshaping the global energy market, the environment, and world politics (Obaid et al., 2002; Wonacott et al., 2003; U.S. Congressional Budget Office, 2006). India is next in line, as its government will try to achieve a better lifestyle for its population.

Market reforms in a country will usually improve production and encourage foreign investment, while nationalism will typically lead to reduced investment, at least in the short term (Kennett and Goswami, 2006). A growing number of countries across South America, for example, are opting for more nationalist, left-leaning governments (e.g., Bolivia, Ecuador, Venezuela) as opposed to the market-oriented policies of previous moderate, socialist governments. Throughout Africa, South America, and the Former Soviet Union, governments and their NOCs are renegotiating contracts to take in more revenue via taxes and royalties (Coburn, 2005). In the 1990s, Russia divested itself of some off its biggest industrial assets in often-controversial privatizations. Since 2002, the Kremlin has sought to regain control of the energy sectors. State-owned energy companies OAO Gazprom and OAO Rosneft, for example, have purchased independent oil producers, OAO Sibneft and OAO Yukos. Iran continues to feud with the West over its nuclear ambitions, and continued conflict in Nigeria maintains a risk premium in the price of oil.

Geopolitical events can create pressures in either direction, with both short and long-term consequences, and it is easy to overstate their influence and underestimate their effect. Geopolitical events by their nature are impossible to predict (Mitchell, 1996; Mitchell et al., 2001).

7.5. Geology

The geology of a country or province will ultimately determine the energy supply potential of the region. There is a finite amount of oil and gas resources in the world, but whether we ever extract all of the resource or find other alternative sources is a matter of heated debate (Campbell, 1997; Lynch, 2003; Maugeri, 2004; Reynolds, 2005; Watkin, 1992). At present, there is no good substitute for oil or gas, and so as long as demand outstrips supply, prices will remain at elevated levels.

7.6. Access to Reserves

Resources in the ground are the property of the state, except in a few countries around the world such as the United States and parts of Eastern Canada where private ownership of minerals is legal (Barrows, 1983). Countries maintain sovereign rights over the land and mineral resources within their physical territory, and in the case of access to water (lake, sea, and ocean), offshore continental shelf acreage. Opportunity to explore for and develop oil reserves depend on host country policies on foreign investment, depletion rates, and environmental protection. By the mid-1990s, many countries had at least partially opened their oil sector to foreign investment, but three major oil-producing countries still remain totally closed – Kuwait, Mexico, and Saudi Arabia. Investment in Russia, China, Iraq, and Iran remain constrained by regulatory, political, and administrative barriers and delays (International Energy Agency, 2003).

7.7. Technology

Technological advances in the oil and gas industry have been phenomena over the past two decades. Vastly increased computing power has stimulated the development and interpretation of geophysical data, which has led to a better understanding of reservoir characteristics. Progress in 3-D and 4-D seismic techniques, advances in deepwater exploration, horizontal drilling, multiphase pumps, floating production storage and offloading vessels, have all made a contribution to increasing supply. It is widely recognized that technological advances have improved drilling productivity and recovery rates and reduced production costs, especially offshore and in frontier areas, but its impact is difficult to isolate. Technological advances raise the proportion of a field which can be economically recovered, while improvements in infrastructure allow smaller and/or deeper fields and less productive wells to be economically produced. Improving technology will continue to make more reserves available.

7.8. Exchange Rates

World oil is priced in dollars and transactions are settled in dollars, and so changes in the exchange rate of the U.S. dollar can affect the level and distribution of oil demand in both directions. The effect of a declining dollar depends on the import/export status of the nation and how the currency of the country adjusts to the changing value. If the value of the dollar declines against other currencies, the dollars received by oil exporting nations are worth less in purchasing power, which may impact their production decisions. For oil importing nations, the impact depends on the trade-off between the advantages of an appreciating currency and product exports (Pirog, 2005a).

7.9. Depletion (Existing Fields)

As a field is produced, its productive capacity declines if no investments (additional drilling, enhanced recovery schemes, etc.) are made. With no additional investment, a field will typically decline at a rate ranging between 5-20%. Investment will slow the decline of the field, depending on the geology of the field, and the nature of the investment. The majority of investment in the oil industry is currently spent to compensate declining production rates. The International Energy Agency (IEA) estimates that about 20% of investment is required to meet new demand growth, with the remaining 80% used to compensate for decline (International Energy Agency, 2003).

7.10. Discovery Rate (New Fields)

High oil and gas prices stimulate drilling activity, which usually results in increased production, but the geology and maturity of the region in which drilling occurs are constraining factors. Geology determines what resources are ultimately available, while technical and exogenous factors – including infrastructure, field complexity, proximity to market, oil price – determine if the field is commercial. If the region is mature and infrastructure well developed, field discoveries will be small on average but can be brought on-line with relative ease, while if the region is frontier, the chance of a large discovery is greater but the development cost will be more.

7.11. OPEC Policy

OPEC was organized in 1960 by Saudi Arabia, Iran, Venezuela, Iraq, and Kuwait in protest of the multinationals move to reduce posted prices for exporting countries. Today, there are 10 member nations, excluding Iraq. The stated objective of OPEC is to

> "… co-ordinate and unify petroleum policies among Member Countries, in order to secure fair and stable prices for petroleum producers; an efficient, economic, and regular supply of petroleum to consuming nations; and a fair return on capital to those investing in the industry."

OPEC seeks to create favorable oil prices for its members by assigning production quotas to its member nations (Table A.17) with the goal of limiting the supply of crude oil available on the world market. The behavior of OPEC and its institutional structure is the subject of intense academic and government interest, and many conflicting viewpoints have been espoused about the nature of OPEC, its success in maintaining a price band for crude, its incentives for increasing supply, and its expected role in the future.

OPEC supply can be considered a planned and managed variable, resulting from the coordination and collective decisions of the member nations. The level of supply is frequently adjusted, sometimes several times a year, in response to anticipated developments in market fundamentals, where factors and expectations of factors such as the price, demand, stock, and non-OPEC supply are used to make adjustments (Smith, 2005).

OPEC's stated policy is to reduce the market volatility and to stabilize the oil price within a suitable price band. OPEC countries are not uniform in their behavior, however, and each has different policies to maximize income (e.g., quota cheating) and openness to foreign investment.

7.12. Role of National Oil Companies

The behavior and strategies of NOCs and their investment and trade patterns are important to oil supply because they control the vast majority of proven reserves in the world. Saudi Arabia alone controls nearly 25% of the world's proved oil reserves. Iran

(11%), Iraq (10%), Kuwait (8%), UAE (8%), and Russia (6%) also control significant quantities of proved reserves and have mostly limited foreign investment in the sector. National Oil Companies are expected to have a substantial, long-term, and growing impact on the pace of resource development, market stability, and geopolitics.

There is a wide diversity in the structure of NOCs. Prior to 1960, most NOCs formed around specific local issues and the desire for self-sufficiency, while during the 1970s, many countries nationalized their assets to regain control from foreign companies and achieve higher rents from production. In the 1980s, after oil was commoditized and price volatility and falling prices negatively impacted profitability, oil ministries and NOCs began to restructure to increase their efficiency and return on capital standards were increasingly employed. In the 1990s and post-2000, countries with economies in transition reorganized their oil ministries to form NOCs and private firms (Jaffe, 2005; National Oil Company Case Study Research Protocol, 2005).

Economic liberalization, market reforms, and western-style management reorganizations have characterized the oil and gas industries of major energy producing countries such as Russia, Norway, Canada, and Malaysia, as well as major consuming countries such as China, Brazil, Japan, and India. National Oil Companies are in the process of re-evaluating and changing business strategies with significant consequences for international majors and market stability.

7.13. Exceptional Events

War, riots, political instability, natural disaster, and terrorism impact the supply and demand for oil and gas. Exceptional events by definition are unique and impossible to predict. The impact of exceptional events on oil and gas markets has potential short-term and long-term consequences, depending on the state of the world oil market at the time of the event. Some notable examples of exceptional events from 2001-2005 include:

- War in Iraq,
- Terrorist attacks in New York, Saudi Arabia, and elsewhere,
- Political unrest and riots in Nigeria, Venezuela,
- Nationalism in Bolivia, Ecuador, Venezuela, Russia,
- Hurricanes Katrina and Rita along the Gulf Coast, and
- Legal conflict between Yukos and the Russian government.

According to Department of Energy statistics, the Iraqi invasion and aftermath rank as the third-largest cumulative oil disruption since World War II, behind the nationalization of Iran's oil fields in the early 1950s and the Iranian revolution in 1979 (Table A.18). Weather-related disruptions will impact production in the short run, but are not expected to have significant consequences in the long-term. Terrorist activity and political unrest can negatively impact air travel and other sources of demand, and directly impact supply reliability.

Discontinuities impact the ability to forecast supply and demand trends over time (Lynch, 2002; Stevens, 2000 and 2001). When discontinuities occur, the future will be fundamentally different and historic trends significantly disrupted. System discontinuities are therefore frequently ignored in analytic models, but such impacts are integral to the nature of the system. The further into the future a forecast is made, the larger and more frequent potential discontinuities will arise.

7.14. Market Manipulation

The primary markets in oil price formation are NYMEX and the International Petroleum Exchange. The goal of financial traders is to make a profit on changes in the price of a contract, which necessitates creating price movement, regardless of the supply-demand fundamentals of the market. Market manipulation may impact price formation and the signals governing the supply-demand balance.

7.15. Government Policy

Government policy takes many forms and can have a direct impact on supply and demand and investment patterns. Each nation in the world has a variety of regulations which affect investment in the oil and gas sector, including tax structure, price controls, import/export controls, access to prospective territories, fiscal policies governing E&P activity, etc. Each nation also has geopolitical aims which affect investment trends, partnerships, strategies alliances, and regional cooperation. Policy variables are notoriously difficult to model and are subject to a number of competing political processes.

7.15.1. Licensing and Incentives: Governments control investment in the oil and gas sector primarily through their policies on foreign investment, the number of tracts leased, and the frequency of license rounds. The opening of a country or region, or the expansion of license acreage, may shift investment to the region, depending on the perception of the industry and the state and stability of the oil markets at the time. Governments may also provide incentives for operators, such as through royalty relief and other mechanisms, to promote exploration activities in high cost-high risk areas, and during times of low oil price. The openness of countries to foreign direct investment is an important factor in determining how much investment occurs in the country.

7.15.2. Taxation: Hydrocarbon taxation strategies are variable and dynamic, depending on government interest, the global economic environment, and on the income the country wishes to derive from hydrocarbon production. Each country is a special case. Every year is a specific event. Tax rates vary by country and over time, and often, on a field-by-field, company-by-company basis, negotiated as part of the fiscal system. Taxation systems evolve rapidly in response to market conditions and the margin that the state wishes to allocate to the oil companies.

Producing/exporting countries try to derive the maximum possible income from their hydrocarbons, while industrialized/importing countries generally attempt to encourage domestic production by stable fiscal regimes and tax incentives. Producing exporting countries will try to secure the maximum amount of revenue through taxation. Major consuming/importing countries will adjust their legal and tax systems to encourage E&P activity on their territory to improve their balance of payments and to protect the industry.

7.15.3. Fiscal Regime: The fiscal terms offered by host governments are a critical determinant of the attractiveness of an upstream investment. All governments have to balance their desire to maximize their share of rent versus the need to encourage investment. This is a matter of judgment since the attractiveness of a region depends on perceptions of geological, economic, and political risks relative to projected returns. The stability of a fiscal regime is important, since frequent changes or changes applied retroactively will force investors to raise their hurdle rates, which may limit future investment.

The E&P market is characterized by sometimes sudden changes in an area as a consequence of the changes in the power relationships between the producing states and the international companies. The period following the second oil crisis witnessed the growing power of the producers/exporters and a tightening of the terms of E&P contracts. Oil companies, eager to sign new contracts and anticipating further oil price increases, found themselves in a weak negotiating position. The trend reversed in the mid-1980s as oil prices plunged and E&P activity in producing countries was curtailed. Countries reviewed their legal framework and introduced more flexibility into their contracts. The decade of the 1990s witnessed increasing government control over the activities of oil and companies. It is likely that the industry will continue to shift between these extremes.

7.15.4. Environmental Regulations: Environmental considerations and public opposition to oil and gas projects affect opportunities for investment and the cost of projects. In the U.S., moratoriums on drilling in federal onshore lands and offshore coastal zones have been in place for many years, which obviously impact the potential supply of domestic oil and natural gas.

7.15.5. Conservation:

Conservation policies of a country and tax rates on petroleum products are an important factor affecting the demand for crude oil.

7.16. Political Risk

Whenever oil and gas capital flows overseas, political risk is a real and ever-present danger. In the 1950s, companies were mostly concerned with nationalization, while today, the risk is for the terms of the contract to be re-written to such as degree that operations are no longer economic. The widespread use of production sharing agreements has largely removed the nationalization risk, since the oil now belongs to the host county, but political risk remains a significant factor in many parts of the world as contract terms are renegotiated (McArthur et al., 2000).

8. FACTORS THAT IMPACT E&P INVESTMENT

In the E&P industry, many factors influence drilling and development decisions and the manner in which a company allocates capital across its portfolio. A firm should seek to maximize profits, but financial forces and shareholders (banks, fund managers, etc.) may require a firm to pursue "growth" (reserves volume) or diversify its operations. At a corporate level, the decision to allocate resources in any given year depends upon its cash flow position, the profitability of the business, preferences for risk taking, competition in the global marketplace for capital, available prospects for drilling, strategic decisions, shareholders obligations, and the firms outlook for the future. At the time a company sets its budget, it should be able to make a fairly reliable projection of next years production rate and estimated cost. Typically, a planning horizon for oil prices is assumed and projects are evaluated on a common and consistent basis, where judgments on the risks and rewards of the projects under a variety of price scenarios and geologic, technical, production, government, tax, and legal factors are considered (Seba, 2000).

8.1. Financial Performance

Investment decisions are made within a firm based on the amount of money a company has to invest, which depends on commodity prices, cash flow, profit margins, and expected profit. High commodity prices tend to lead to higher profit, and vice versa, but since costs and taxes also change with price, the correlation is not perfect. Profit can only be determined on a project-by-project basis taking into account the terms of the fiscal regime, royalties, taxes, production costs, and other relevant factors.

Cash flow is the primary source where companies acquire funding for new projects. The price of crude and derivative products are major determinants of cash flow, but like profit, available cash flow is also influenced by several other factors, including dividend reinvestment, share buybacks, and debt reduction. Cash flow tends to follow movements in prices and production. Companies react to reduced cash flow by cutting upstream investments and shifting the available capital to projects in other regions of the world with a better risk-return profile. If suitable projects are not available elsewhere, the company will hold a cash inventory.

The firms that make up the oil and gas industry in the U.S. use shareholder (public) or private capital to engage in business operations. When firms make profits they are obliged to return those profits to shareholders, either directly in the form of dividends or indirectly through share repurchases. In a market economy, decisions on the use of profit are the responsibility of the industry in which they are earned.

8.1.1. Dividend Strategy: Dividend policy varies widely with each company, based on factors such as company size, corporate outlook, and cost of capital (Brealey and Myers, 1991). Majors tend to act conservatively based on long-term planning horizons. Shareholders of the majors expect a larger portion of their return to be derived from dividends than smaller companies, and thus will normally tolerate a lower level of production growth.

<u>8.1.2. Share Purchases:</u> A company that re-purchases its shares will likely see the value of the shares outstanding increase. The company may then choose to re-sell their shares on the market if it needs capital in the future.

<u>8.1.3. Debt Reduction:</u> Banking institutions are an important source of funds to the oil and gas industry, but generally cost more than other forms of financing. Most companies rely on banking for short term borrowings such as a line of credit, revolving credit agreement, transaction loan, or dedicated cash operating income payment.

8.2. Availability of Capital

If the capital employed in a company does not generate an adequate return, the company will have limited access to new capital, as investors and lenders seek more profitable opportunities elsewhere. The availability of capital is not expected to be a constraint to investment for integrated oil and gas companies in the short-term, however, because of the return on investment (ROI) for the sector over the period 1993-2002 has been high for publicly traded companies in the Organization for Economic Cooperation and Development (OECD) and non-OECD regions (Figure A.12). Integrated companies realized the highest return (12%) across various industries, while the ROI of independent companies in E&P was 6.3%, the lowest for all industry sectors.

8.3. Budget Allocation

Oil and gas companies will expand and upgrade various aspects of their operations, such as refining, petrochemicals, marketing, and transportation, at various times depending on the strategic rationale of the company. Companies may also diversify into other industries such as mining or non-energy related activities. The degree of vertical integration affects the degree to which capital is allocated across the various segments of the business.

8.4. Business Opportunities

Investment in the oil and gas sectors may be constrained by a lack of profitable business opportunities. Upstream investment decisions depend on company's assumptions regarding future oil price, planning horizons, hurdle rates, etc. (Chua and Woodward, 1992; Turner, 1983). Oil companies that favor a conservative price assumption, perhaps reflecting pressure from shareholders to maintain high investment returns, are likely to have a decline in capital spending.

8.5. Oil Price

The price of hydrocarbons is probably the single most important factor in the E&P industry, because for companies that produce oil and gas, price and income are closely related: lower prices reduce income, high prices increase income. The correlation is not perfect, of course, but the relationship is strong enough to suggest that the price of oil is likely to be a reasonably good explanatory variable for E&P investment in markets such as the Gulf of Mexico, Canada, and the North Sea. In other parts of the world, however, the correlation between price and capital expenditures is likely to be weaker and more closely dependent upon the nature of the field developments, project size, time lags, planning horizon, and other unobservable variables. High prices tend to lead to increases in company exploration and development budgets, and if the current market follows past patterns, increased activity and expansion of supply.

Price enters the drilling decision through the calculation of the potential payoff associated with a play. High prices stimulate drilling decisions, because the economic and reward structure appear more favorable. When prices drop, companies are inclined to curtail some of their exploration activity, and if prices stay low long enough, companies will shut-in high-cost wells, delay development activity, and postpone high risk ventures. At low commodity prices, M&A activity is usually more prevalent, with majors selling properties and shifting their budgets to regions/activities with a greater return. Strong prices will tend to delay divestiture programs, since properties that are marginal at low prices become profitable. In recent years, as demand-side NOCs have begun to secure reserves for their host country through high-cost acquisitions, these relations may change.

8.6. Oil Price Volatility

Oil and gas investment has tended to fluctuate with oil prices, especially in recent years, but the relation is not a universal phenomenon and several other factors are involved. A careful examination of the historic record indicates that capital spending in E&P may increase or decrease when the price of oil increases. A price collapse will typically lead to a reduction in investment spending, although the magnitude will vary depending on several other (unobservable) variables. High prices tend to encourage investment spending, but the life cycle of exploration and development means there is a several year delay. Price uncertainty will raise the option value of future investments and firms are likely to postpone or reduce expenditures on irreversible investments. IEA analysis has found support for an inverse relationship between upstream oil investment and price volatility (International Energy Agency, 2003).

8.7. Merger and Acquisition Activity

If a company is under merger, acquisition, or reorganization this will typically slow down or delay capital spending. Corporate mergers in which one company acquires another companies total assets impact exploration and development decisions. M&A activity may improve the market position of the firms involved, but they do not change the oil supply balance of the world. M&A activities are likely to help majors compete internationally to acquire acreage and develop joint partnerships with NOCs in the future.

8.8. Debt/Equity Position

Companies with a significant amount of debt will have fewer funds available for reinvestment. Restructuring by cost reduction and asset divestiture will lead to reduced spending in the short term, and possibly longer term future returns.

8.9. Business Uncertainty

Investment decisions in capital intensive and high risk industries such as E&P tend to be based on full-cycle project economics, expected long-term prices (Boudreaux et al., 1999; Wehrung, 1989), portfolio decision-making (Edwards and Hewett, 1995; Hightower and David, 1991), and strategic rationale (Seba, 2000). Capital requirements in E&P compete with other segments in the petroleum industry as well as the capital needs of other industries. Uncertainty about the future price of oil and gas and global conditions impacts allocation decisions and external evaluations by bond raters and capital markets (Pirog, 2005b).

The higher profitability of integrated oil and gas companies relative to independents and service companies (recall Figure A.11) reflects the nature and diversity of their assets and operations. The volatility of ROI by industry is depicted in Figure A.12. Exploration and development and service companies have a volatile ROI, while the volatility of integrated companies is comparable to the chemical industry. For decisions that require a large amount of capital, increased uncertainty tends to slow down or stop investment in order to reduce risk. Uncertainty over regulations and license rounds would also be expected to lead to reduced capital investments.

8.10. Capacity Constraints

The E&P industry is composed of many diverse companies and resource constraints which are likely to vary widely among individual companies and regions of the world. E&P projects are designed and engineered by a combination of internal company resources and third-party companies, ranging in size from small engineering firms to multi-billion dollar companies. The support equipment and services required (e.g., rigs, vessels, personnel, materials) to successfully execute an E&P project is driven by supply and demand forces at a particular place and time, and has not historically been a significant constraint to project implementation. There is evidence to indicate that reduced capital spending by oil-services companies, which result in less availability of oilfield equipment, has at times forced oil and gas companies to scale back their investment programs (International Energy Agency, 2003), but the impact is usually short-term because an increase in demand will increase dayrates[9], which will stimulate new investment, increasing supply and competition, and balancing the market.

8.11. Resource Availability

Oil and gas companies create value by investing in those projects for which the market value of cash inflows exceeds the required investment outlays. The purpose of drilling is to discover reserves, but it costs money to identify plays, acquire and interpret seismic data, and drill wells. If the resources found are not adequate to make a sufficient return on capital, then the E&P industry in the region will drop and shift investment where the return is acceptable. If the region is not prospective, or if the NOC controls the best

[9] For example, if rig rates remain high for a sustained period of time, then cold-stacked rigs will come back into service and new-build orders will occur, increasing rig supply and forcing down rates.

blocks, then foreign capital will eventually diminish and move to other regions or business opportunities.

8.12. Risk Strategies

Investing in energy projects in developing countries and the transition economies is generally riskier than in OECD countries because of institutional and organizational reasons; lack of clear and transparent energy, legal, and regulatory frameworks; and poorer economic and political management. There is also a significant difference in the risk and return profile between an export project and a project for the domestic market in non-OECD regions. Risk strategies and the means to manage risk vary with each company.

8.13. Government Policy

Governments choose their production capacity potential based on a number of factors. OPEC producers, for example, may determine that curbing investment and limiting capacity would boost net earnings from exports. OPEC producers also recognize the risk that other producers (OPEC or non-OPEC) might boost their capacity more quickly, resulting in lower export earnings for the country. Governments might defer investment to preserve hydrocarbon resources and revenues for future generations (Reynolds, 2005). This could be a legitimate policy for a country with relatively high GDP per capital and no pressing need for additional oil revenue to fund infrastructure or social programs. If governments increase taxes and royalties on production, or otherwise change the terms and conditions of the fiscal regime, lower profitability of upstream projects might deter investment.

8.14. Exogenous Variables

Numerous external factors also play a role in the amount of capital a country can invest in its oil and gas sector (International Energy Agency, 2003):

- If a country’s national debt is high and there is a need to borrow large sums to finance new projects, investment may be delayed.
- National sovereignty might discourage reliance on foreign investment.
- Legal and commercial terms and fiscal regimes impact how much external capital producers are able to secure.
- In many countries, education, health, defense, and other sectors of the economy may command an increasing share of government revenues and constrain capital flow to the oil sector.
- Inadequate infrastructure to support oil and gas development, insecurity, and conflict could constitute additional barriers to investment.

9. E&P EXPENDITURE TRENDS

Exploration and production activity cannot be explained solely on the basis of geology. Politics, economics, technology, regional and global markets all act to preclude, foster, or inhibit E&P activity and capital investment. E&P activity varies with a country's demand for crude oil and natural gas within its border, as well as the desire to export oil and gas as a means of gaining foreign exchange. When the oil industry is in a state of "over supply-low prices," companies are more reluctant to invest capital to seek/acquire new exploration sites; when the industry is in a state of "under supply-high prices," companies more aggressively seek out exploration opportunities. Increasingly, oil and gas companies will be competing with NOCs to secure exploration acreage, and although there is yet to be significant partnering between the two parties, the survival of oil and gas companies rely on access to resources, and so movement in this direction may be inevitable.

9.1. U.S. Major Energy Producers

One of the best sources of public data on the financial and operating developments in the U.S. petroleum sector is the EIA's *Performance Profiles of Major Energy Producers*. The EIA collects financial and operating data through a Financial Reporting System (FRS) Form EIA-28 from a sample of major U.S. energy companies that are considered representative of the U.S. energy industry. A "major energy producing" company must satisfy at least one of the following criteria to be included within the survey: (1) control at least 1% of U.S. crude oil or natural gas liquids reserves or production, (2) 1% of U.S. natural gas reserves or production, or (3) 1% of U.S. crude oil distillation capacity or product sales.

Information is collected for the corporate entity as well as by lines of business within the company; e.g., petroleum, downstream natural gas, electric power, non-energy, and other energy. The petroleum line of business is segmented into exploration and production, refining and marketing, crude and petroleum product pipelines (for domestic petroleum), and international marine transport (for foreign petroleum).

The FRS data are separated by regions which include U.S. onshore, U.S. offshore, Canada, OECD Europe, former Soviet Union and Eastern Europe, Africa, Middle East, other Eastern Hemisphere (primarily Asia Pacific), and other Western Hemisphere (primarily South America).

The composition of the FRS group of companies changes over time, but since the changes are usually incremental, year-to-year comparisons of the survey data are considered meaningful. In 2004, 29 major energy companies reported data, representing operating revenues of $1.13 trillion, equal to about 15 percent of the $7.4 trillion in revenues of the Fortune 500 corporations (U.S. Energy Information Administration, 2004). About 94 percent of operating revenues of the companies were derived from petroleum operations. The FRS companies accounted for 46% of total U.S. crude oil and natural gas liquids (NGL) production, 43% of natural gas production, and 84% of U.S. refining capacity.

9.1.1. Return on Equity: The return on stockholders equity for the FRS companies varies considerably from year-to-year and has fluctuated with the S&P Industrials (Figure A.13). Oil and natural gas production was the most profitable segment of the business ($59 billion), followed by refining/marketing ($22 billion), and non-energy activities ($4 billion).

The return on net investment is defined as the net income earned by the line of business (excluding unallocated items such as interest expense) as a percentage of net fixed assets. The return on net investment for domestic oil and natural gas production operations has exceeded foreign operations in recent years (Figure A.14), whereas prior to 1995, the returns from foreign operations dominated.

9.1.2. Sources and Uses of Cash: The sources and uses of cash for FRS companies are shown in Table A.19. Cash flow from operations amounted to $136 billion in 2004, with oil and natural gas production comprising 65% of the total. At significantly smaller levels, cash was also raised through disposal of assets, long-term debt, and equity security offerings.

Cash flow is a primary determinant of the level of capital investment, ranging anywhere between 15-40% of net income in a given year (Beck, 2004). In 2004, the largest use of cash was for capital expenditures, which increased 8% to $86.5 billion (Table A.19). Petroleum activities accounted for 86% of capital expenditures. Dividends to shareholders were the second largest use of cash, followed by reduction in long-term debt and stock repurchase.

9.1.3. Capital Expenditures: Capital expenditures for exploration[10], development, and production generally follow changes in cash flow, except most recently in 2004, where a wide differential resulted (Figure A.15). A positive change in oil price is usually associated with a less moderate but positive change in cash flow, while a negative change in oil price is often correlated with a zero or negative change in cash flow. In Figure A.16, worldwide expenditures are broken out according to exploration, development, and production activities.

Regionally, the U.S. onshore continues to receive more E&P expenditures than any other region, followed by the U.S. offshore (Table A.20). Exploration expenditures for the U.S. offshore are almost twice onshore expenditures (Figure A.17), while expenditures for development continue to predominate in the U.S. onshore (Figure A.18). The U.S. continues to attract a disproportionate share of FRS capital investment because oil is found at the market place, can be developed with low cost infrastructure, and can be brought on-line in a short period of time. The political risk in the U.S. is small, or negligible, and the potential for commercial discovery is still considered strong.

[10] Exploration costs include all the investment that is needed before a discovery is confirmed, including geophysical and geological analysis and drilling exploration wells. Development costs cover spending after a discovery is confirmed and delineated. Development costs include the installation of surface equipment and facilities and drilling production wells. Production costs represent the costs to operate and maintain wells and related equipment after hydrocarbons have been found, acquired, and developed.

Foreign exploration and development expenditures have not changed significantly over the past several years. Limited access to prospects in the Middle East and South America has restrained E&P expenditures in these regions, while Africa and Canada remain the favored destination for FRS companies. FSU countries continue to exhibit significant growth in development expenditures.

9.2. U.S. Independent Producers

The perceptions of U.S. independents are surveyed in a variety of sources. The *American Oil & Gas Reporter*'s annual survey of independent operators' list factors that operators consider inhibits drilling and production activity (Campbell, 2005). In 2005, concerns about price volatility lead the list, cited by 69% of the respondents as a reason why the industry is not drilling at a more robust pace, followed by equipment/personnel availability (58%), higher equipment and service costs (53%), environmental regulations (36%), smaller reserve targets (34%), insufficient prospect inventories (34%), and acquisition opportunities (26%). Small and mid-size operators primary concern is price volatility, while for large operators, the availability of equipment and personnel is considered the limiting factor.

In a Grant Thornton survey, executives and chief operating officers from 75 independents representing total average assets at the end of 2005 of $836 million and average revenues of $167 million were questioned. Executives responded that area restrictions, good projects, service costs, availability of equipment, and the aging work force were the primary factors expected to limit capital spending in the upcoming year.

Survey results are notoriously difficult to generalize and compare, and in almost all cases, the information simply confirms generally accepted industry perceptions. It is reasonable to suspect that the perceptions of executives and other decision makers would translate into concrete, verifiable behavior, although in practice the link is tenuous and difficult to verify. It is also difficult to build models of industry behavior based on survey data because of the variability of the results and its limited application. In some years, independents may spend more domestically and majors may be most interested in unconventional plays; in other years the reverse may be true. In some years, independents may be more interested in exploration activities and demonstrate greater sensitivity to price changes; in other years the reverse may be true. Surveys usually cannot provide adequate information from which to generalize. Indeed, one must be exceedingly careful when attempting to interpret and/or explain any "patterns" or "trends" in the industry with behavior and/or macroeconomic models.

9.3. Capital Expenditures

9.3.1. Data Source: Lehman Brothers performs a semiannual E&P spending survey based on a poll of international firms, including privately held U.S. and Canadian independents and several National Oil Companies. Smith Barney, Chase/Saloman Brothers, John S. Herold, Harrison Lovegrove & Co., Citigroup Investment Research, Grant Thornton, Prudential Equity Group, Inc., Raymond James & Associates, Arthur

Anderson (now Accenture), and other financial institutions perform similar surveys. Government agencies that perform capital expenditure reviews and outlooks include the Energy Information Administration (EIA), International Energy Association (IEA), and Institute of Petroleum (IFP). Consultancies such as IHS, Ziff Energy, Wood MacKenzie, Douglass-Westwood, and trade publications such as *The Oil and Gas Journal*, *American Oil and Gas Reporter* (O&GJ), and *World Oil*, also conduct annual capital spending surveys.

The surveys typically cover issues such as:

- Expected spending plans for the upcoming year, by region (U.S., Canada, international), activity (upstream, downstream, business segment), and company type (majors, independents, NOCs);
- Perceptions on expected changes in service and drilling costs, merger and acquisition activity, oil and gas price assumptions, availability of prospects, availabilities of drilling services, impact of technology on spending plans, remaining reserves expected to be found, human resource issues, compensation for technical staff; and
- Perceptions on the relative attractiveness of investment opportunities (exploration vs. development, U.S. vs. international, drilling vs. acquisition activity, oil vs. gas plays), expected operating cash flows, spending plans (leasing, seismic, onshore vs. offshore).

Significant variations in the manner in which data is compiled and processed make it difficult to compare survey results. In Table A.21, for example, global upstream oil and gas investments for four surveys are compared from 1995-2002. Wide variation exists, suggesting that a composite average is probably the most representative statistic, avoiding the uncertainty and bias associated with any single data series. Creating a composite average of this sort, however, based on divergent survey data is methodologically problematic.

9.3.2. U.S. and Non-U.S. Capital Spending: In the O&GJ survey, U.S. capital spending is decomposed according to three upstream categories: drilling-exploration, production, OCS lease bonus; and eight downstream categories: refining, petrochemicals, marketing, crude and products pipelines, natural gas pipelines, other transportation, mining, and miscellaneous (Table A.22).

Capital expenditures by U.S. firms for U.S. upstream and downstream sectors generally follow the U.S. majors spending profiles. Investment in the U.S. has been volatile over the past two decades, generally tracking the price of oil, the amount of capital flowing into the industry (cash flow), and the level of profitability.

9.3.3. Worldwide Capital Spending: Global capital expenditures represent the sum of all public, private, and state-owned companies in the oil and gas industry (Table A.23). Spending plans for oil and gas companies outside North America, South America, and

Europe, are either mostly unavailable (Middle East, Africa) or available in incomplete form (Asia Pacific). Worldwide investment in E&P has tended to follow the price of oil, especially in the years prior to 1998, but the correlation is noisy and dependent upon the data series employed. When the price rises or falls, exploration budgets adjust quickly to the changes, while development budgets tend to be delayed. Some regions of the world react faster to price variations than others, with North America generally considered to be the most price-sensitive.

After the nationalizations in the 1960s and 1970s, the majors needed to redeploy capital throughout the world to access acreage. Exploration and production budgets matched the price shocks of 1973 and 1979 as demand growth increased. From 1981-1987, prices suffered as excess supply developed from the previous investment boom. Capital expenditures were reduced and prices retreated. From 1987-1998, prices stabilized below $25/bbl and a more cautious approach to investment was realized. Following the price collapse in 1998, capital expenditures took a temporary fall before continuing on an upward slope.

9.4. IEA Investment Forecast

The IEA predicts that an investment of over $3 trillion, or $103 billion per year, will be needed in the oil sector through 2030 to permit an increase in oil supply to 120 million BPD by 2030 (International Energy Agency, 2003). Exploration and development is expected to dominate the investment, accounting for over 70% of the total. Investment in non-conventional oil projects in Canada and Venezuela is expected to account for a growing share of total upstream spending. Offshore fields are expected to account for about a third of the increase in production from 2002 to 2030, but will take a larger share of investment, because the unit costs are higher compared to other developments.

9.5. Lifting Costs

Lifting (production) costs represents the costs to operate and maintain wells and related equipment and facilities after hydrocarbons have been found, acquired, and developed. Lifting cost is a reliable and meaningful measure, and can be compared across companies if a common accounting framework is applied. Lifting cost is a measure that may be used to evaluate the extent to which a company can control its operating costs and/or how efficiently the company is getting oil and gas out of the ground. Two mechanisms are responsible for boosting productivity and reducing lifting costs: technical progress and industry reorganization.

Total lifting costs are divided into direct costs and production taxes. Direct costs tend to be correlated to the price of oil since increases in oil price tend to bring an increase in the cost of service and supply costs. Production taxes may also be a function of the price of oil and other factors, especially under Production Sharing Agreements.

For the FRS companies, Canada and the Western Hemisphere region have the lowest direct lifting costs in the world, while the Former Soviet Union and Eastern Europe have the highest direct lifting cost (Table A.24). This is likely due to a combination of political systems, technical progress, and industry organization. Direct cost in the U.S. offshore lies between these extremes. Domestic and foreign direct lifting costs are nearly identical and have trended together for the past decade (Figure A.19).

9.6. Finding Costs

Finding costs is one of the most frequently cited ratios utilized in evaluating the efficiency of a company in adding new reserves. Finding costs is also one the most misapplied and ambiguous measures in the industry (Adelman, 1993; Gaddis et al., 1992). Finding and development costs can be defined in many ways, and there is no general consensus on the best way to define the measure, leading to significant limitations in measurement and interpretation. In the FRS Form EIA-28, finding costs is defined as the costs of adding proven reserves of oil and gas through exploration and development on a BOE-basis, including the purchase of properties that might contain reserves. A 3-year weighted average is reported in 2004 constant dollars (Table A.25). Finding costs have been rising since the mid-1990s and have been the most variable for the U.S. offshore region (Figure A.20).

10. IMPLICATIONS OF EXPECTATIONS ABOUT FACTORS AFFECTING CAPITAL BUDGETING AND DECISION MAKING FOR THE OCS GULF OF MEXICO

Keeping in mind the caveats and qualifications outlined in the previous sections of the report, the following tables attempt to use the format developed to relate “conventional expectations” concerning those factors to future investment trends in the OCS Gulf of Mexico. The “conventional expectation” is a subjective characterization by the authors of the perceptions, opinions, and analyses prevailing among those that follow the oil and gas industry. Our characterization, as well as the perceptions, opinions, and analyses we offer, may be neither complete nor accurate. We may also err in drawing our characterizations. In any event, the reader can form his own thoughts in the matter. Alternative characterizations can be substituted and alternative implications derived at the reader’s discretion. The tables are simply a way to relate the implications of the complex and interrelated factors outlined in the previous sections of the report for the Gulf of Mexico region.

Table 1

Factors that Impact Supply and Demand

FACTOR /REPORT SECTION	CONVENTIONAL EXPECTATION	IMPLICATIONS FOR INVESTMENT IN THE OCS GULF OF MEXICO
7.1 Economic Activity	Rapid growth in most populous developing countries, resumption of growth in Japan and Europe, and average or above growth in the U.S. will keep global petroleum demand increasing faster than in the previous two decades. Although global or regional recessions could always slow or stop growth, the impetus for growth seems widespread and resilient to political and cultural disputes and conflict.	Growth in demand is the factor responsible for the expectation of continued higher oil and gas prices, which is an important driving force for investment in relatively high cost areas like the GOM.
7.3 Price	Demand growth will continue to strain available supply capacity and prices are likely to stay at current high levels or increase.	High prices are the key to the economic vitality of GOM investments. The expectation of their continuation makes investment in domestic oil and gas production competitive with other domestic investment opportunities for the largest private companies.
7.4 Geopolitics	Continued instability, uncertainty and realignment in oil-exporting countries in the Persian Gulf, Russia, FSU, South America and Africa.	Political and institutional stability in the U.S., Canada, and Europe, compared to deterioration and increased risk elsewhere, increases the relative expected value, and attractiveness, of GOM investments.
7.5 Geology	Significant prospects are more likely to be found outside the GOM, but uncertainty about the realism of Saudi Arabian reserve estimates will continue to be a major concern.	Uncertainty about Saudi Arabian reserve estimates is a contributing factor to expectations that higher prices will endure.

Table 1 (continued)

Factors that Impact Supply and Demand

FACTOR /REPORT SECTION	CONVENTIONAL EXPECTATION	IMPLICATIONS FOR INVESTMENT IN THE OCS GULF OF MEXICO
7.6 Access to Reserves	Incremental erosion of existing moratoria on exploration and development of U.S. reserves, but most such areas will remain off-limits. Geopolitical concerns and conflicts and difficulty in working with NOCs limit effective access to reserves in many major producing areas in the rest of the world.	Expansion of access to the Eastern GOM creates new investment opportunities in a stable environment with well developed infrastructure, supporting services, and accessible markets.
7.7 Technology	Somewhat more emphasis on technologies to improve recovery from mature and unconventional fields.	Any progress on recovery technologies from mature fields will help GOM investment prospects.
7.9 Depletion	More GOM production will come from maturing fields, less from new discoveries.	Eighty percent of investment is currently spent to slow declining production, and so there is a modest impetus for increased investment as fields mature in areas such as the GOM.
7.10 Discovery Rates	Frontier regions with potential large discoveries need more investment in infrastructure.	As a mature region with extensive infrastructure, less investment is required to develop and produce new discoveries which make production of smaller fields and higher cost fields more feasible.
7.11 OPEC Policy	Prices are well above the upper bound of OPEC's desired price range, but OPEC has only limited ability or incentive to increase production for economic reasons. Expansion of capacity is not a task that OPEC tries to manage. The circumstances and motivation of individual OPEC members varies.	Less risk of price decline than when Saudi Arabia had the ability to increase production from mothballed capacity quickly and substantially--as was routinely assumed during the 1980s and 1990s. A substantial amount of existing, potential supply capacity is "offline" or not producing in Iraq, Nigeria, and Venezuela for a variety of reasons, but how quickly production could return is questionable. "Too much" capacity being added in Persian Gulf is the

Table 1 (continued)

Factors that Impact Supply and Demand

FACTOR /REPORT SECTION	CONVENTIONAL EXPECTATION	IMPLICATIONS FOR INVESTMENT IN THE OCS GULF OF MEXICO
7.11 OPEC Policy (Cont.)		principal, long-term downside supply risk to prices.
7.12 Role of National Oil Companies	National Oil Companies (NOCs) are more subject to geopolitical considerations and less driven by conventional commercial objectives. Coupled with the Russian retrenchment and aggressiveness by the Chinese, risks of large investments in exporting or in transitional economies may have increased.	Relative investment attractiveness of GOM is increased.
7.13 Exceptional Events	Political instability and uncertainty appears to be spreading rather than moderating.	Vulnerability of deep water operations to major hurricanes and new regulatory requirements to deal with them are the principal new uncertainties associated with GOM investment.
7.15 Government Policy	Political instability in Persian Gulf and Africa, nationalism in South America, economic retrenchment in Russia, and the uncertain path of evolution of the FSU countries reduce the certainty and reliability of current government policies and institutions.	The royalty relief controversy and the potential for the resurrection of some form of excess profit taxation are potential direct uncertainties in the GOM, but neither is of the scale of those in many exporting countries. Climate policy and carbon taxes are longer range uncertainties. Shorter-term uncertainty exists in the GOM about new regulations to address problems observed during Katrina and Rita.

Table 2

Factors that Impact E&P Investment

FACTOR /REPORT SECTION	CONVENTIONAL EXPECTATION	IMPLICATIONS FOR INVESTMENT IN THE OCS GULF OF MEXICO
8.1 Financial Performance	Mega-majors and large integrated companies can maintain high profit levels if they have access to reserves. In 2004, the FRS companies' net income of $81.1 Billion was the highest (in constant dollars) in the history of the FRS series. Smaller independents have not been as profitable as the large firms in the high price environment.	The FRS companies are major players in the GOM and constraints and uncertainties elsewhere enhance the attractiveness of GOM E&P investments for them. Independents have historically been a growing presence in the GOM and opportunities to invest in other areas are more limited.
8.2 Availability of Capital	High profit levels for large integrated firms will enable them to generate or compete for capital effectively. Smaller, less profitable independents may have more difficulty.	The historically anomalous excess of cash flow from operations over E&P expenditures (Figure A.15) indicates an increased availability of internal capital for FRS companies. As expectations about the continuation of a high-price environment harden with time, access to capital by independents also may increase.
8.3 Capital Budget Allocation	Experience of investing in, or merging with, non-oil and gas businesses in the 1980s and 1990s was not good. Some companies are making exploratory or "learning" investments in alternative energy ventures, but for most majors and independents, the core business will remain oil and gas. Competition between U.S. onshore and offshore has been going in the direction of onshore, with 2004 total onshore U.S. E&P twice the 1998 level while the 2004 offshore was at roughly the same level as 1998. Exploration expenditures on the offshore remain about 50 percent higher than onshore.	Diversions to other businesses or increased intra-company competition for investment dollars are not anticipated to change. The payoff from GOM investments (as well as onshore U.S. investments) has been good. U.S. investments should be more attractive relative to other alternatives in capital budgeting deliberations. The principal new negative that may influence capital budgeting decisions is the demonstrated vulnerability of GOM infrastructure to hurricanes.

Table 2 (continued)

Factors that Impact E&P Investment

FACTOR /REPORT SECTION	CONVENTIONAL EXPECTATION	IMPLICATIONS FOR INVESTMENT IN THE OCS GULF OF MEXICO
8.3 Capital Budget Allocation (Cont.)	Refining has to some degree been spun off to specialized refining companies and neither they nor the traditional integrated companies exhibit much enthusiasm for investing in new refineries.	
8.4 Business Opportunities	Limitations on access to domestic reserves and increased risks associated with NOCs and transitional economies are as likely to intensify as moderate.	Some FRS companies will seek non-oil and gas business opportunities, but their business culture has not transferred well in the past. Oil and gas will remain their core business and non-US/Canada oil and gas opportunities have become riskier. Stockholders may push for more aggressive, non-oil and gas investments if dividends fall because earnings are invested in financial assets.
8.5 Oil Price	Expectations that prices will remain at or above current levels is a major change in the fundamental investment parameter for investor-owned oil and gas companies. There is considerable variation in estimates of how capital budgets will reflect this change in economic fundamentals, but standard project decision practices will make many marginal projects now profitable.	With current prices twice or three times as high as they were when projects were implemented, GOM profits are correspondingly higher than anticipated.
8.6 Oil Price Volatility	Demand-driven, much-higher, prices imply a much smaller risk of a precipitous decline in prices than has been assumed in the previous two decades.	Expectations that price volatility has diminished shifts the relative balance of risks away from economic and cost factors and toward the geopolitical, non-economic side. As a higher cost but politically and institutionally stable area, the attractiveness of

Table 2 (continued)

Factors that Impact E&P Investment

FACTOR /REPORT SECTION	CONVENTIONAL EXPECTATION	IMPLICATIONS FOR INVESTMENT IN THE OCS GULF OF MEXICO
8.6 Oil Price Volatility (Cont.)		the GOM is enhanced by this shift.
8.7. Merger and Acquisition Activity	The major industry consolidation and corporate restructuring among the majors during the past decade was driven by the need to be large enough to compete internationally and deal with NOCs effectively. Although size may address commercial risks it is not as effective in mitigating geopolitical risks which have been increasing rapidly. Post-merger adjustments, and their accompanying conservatism with respect to capital spending, have been completed by the mega-majors. Mergers and acquisitions among independents remains active as has historically been the norm.	More FRS companies are large enough to accommodate the progressively larger investments required to develop large projects in deeper water in the GOM.
8.8 Debt/Equity Position	Debt-to-equity ratios of the FRS companies fell to 45 percent in 2004 which is below the average for Standard and Poors (S&P) Industrial Companies. Coupled with substantially increased holding of Treasury bills and cash, this reinforces the expectation that oil and gas companies will have more capital available than has historically been the case as long as prices stay high. According to surveys of independents expectations, neither debt nor capital availability were among the factors they expected to limit capital spending.	Reinforces expectation that capital will be available for GOM projects.

Table 2 (continued)

Factors that Impact E&P Investment

FACTOR /REPORT SECTION	CONVENTIONAL EXPECTATION	IMPLICATIONS FOR INVESTMENT IN THE OCS GULF OF MEXICO
8.9 Business Uncertainty	Hardening expectations about the durability of a high-price, reduced-volatility environment represents a major reduction in economic uncertainty in a capital intensive industry such as oil and gas E&P. The degree to which this offsets the heightened geopolitical uncertainties is an open question.	Oil companies have historically operated in politically unstable countries even in times of considerable crisis.
8.10 Capacity Constraints	Availability of drilling rigs and experienced personnel are widely cited as barriers to exploration and development by FRS companies as well as independents. Similar constraints would also retard development of supporting transportation and processing infrastructure in pioneer areas.	Historically the capital intensive E&P industry has overcome these barriers fairly expeditiously once investment decisions are made. Day rates for drilling equipment are two to three times higher than they were five years ago and effective utilization rates of drilling equipment is 100 percent, but service companies are investing in new equipment aggressively. To the extent that capacity constraints postpone investment activity, however, they will have more depressing effects in pioneer areas as opposed to mature areas with a well developed transportation and processing infrastructure and easy access to markets--such as the GOM.

Table 2 (continued)

Factors that Impact E&P Investment

FACTOR /REPORT SECTION	CONVENTIONAL EXPECTATION	IMPLICATIONS FOR INVESTMENT IN THE OCS GULF OF MEXICO
8.11. Resource Availability	U.S. moratoria and explicit limitation by NOCs or governments limit investment opportunities. There are some indications of a weakening of the moratoria coalition in the U.S. because of state-level budget needs, but major changes are not expected in non-U.S. areas in the current high-price environment. Aspirations for economic improvement in developing and transitional economies remain strong and create pressure to find and develop resources.	Resource limitations make access to resources in the GOM relatively more attractive.
8.12. Risk Strategies	Risks in non-OECD countries are higher for political and institutional reasons. There are few indications are that this disparity will diminish and many expect it to widen because of geopolitical and nationalistic trends and influences.	U.S. political and institutional stability is a major advantage of GOM investments.
8.13. Government Policy	Major uncertainties and risks will remain in the non-OECD countries—especially in the Persian Gulf, South America, Africa and the transition economies.	Although regulatory policy, access to publicly owned reserves, royalty-relief, and similar issues remain, in a global perspective, governmental policy is of much less concern in the GOM than elsewhere.

The global circumstances confronting those making capital budgeting and investment decisions for oil and gas companies have changed in important ways during the past five or six years.

- Economic factors, in general, have improved substantially. Prices, in constant dollars, are very near historic highs for oil and have surpassed those highs for gas--when expressed in constant dollars. Economic growth is strong-to-stable everywhere except Africa and global demand growth has substantially exceeded expectations. Excess production and refining capacity has for all practical purposes been eliminated. Normal adjustments to higher prices will slow demand growth, encourage new supplies and the development of alternative fuels and technologies; however, factors that would precipitate a collapse in prices to levels enjoyed during the 1980s and 1990s are not apparent.

- For non-economic factors, in general, the changes are as pervasive and important, but unfortunately negative rather than positive. Geopolitical considerations, nationalistic aspirations, cultural/religious conflict and their derivative complications have increased the risks and uncertainties associated with petroleum investments in many regions of the world where reserves are believed, or hoped, to be most plentiful. Risks of making petroleum investments in those regions have increased significantly. Historically, however, oil and gas companies have managed to operate confidently and effectively in politically unstable and hostile countries even in times of considerable crisis.

Policies to mitigate or manage non-economic risks are dominated by other, and more fundamental, objectives than creating a stable environment for investments in petroleum development. There are divergent opinions about such policies prospects for success. However, as long as the improved economic factors remain as they are, and the deterioration of non-economic factors is not reversed, the implication is that the attractiveness of investing in mature areas, with existing support infrastructure, located in stable and predictable political and institutional environments, such as the OCS GOM, has increased relative to other opportunities—both opportunities to invest in more commercially rewarding but less politically secure areas, or to invest outside of oil and gas.

11. COUNTRY COMPETITIVENESS

The oil and gas industry is far too complex and dynamic for simple cause and effect relationships to be developed to explain the nature of a country's fiscal regime. The structure of fiscal regimes depend upon many interdependent non-causal factors such as the reserve base and economic strength of the country, oil supply balance, oil prices, evolution of political systems and historic relationship between the industry and the country, field maturity and development stage, regional demand, the country's desire for foreign capital, geopolitical motivations, and many other variables. Countries with low exploration risk and high prospectivity are generally expected to take a high proportion of economic rent, while countries with high exploration risk and low prospectivity must usually offer a larger share of rent to encourage investment.

11.1. International Petroleum Arrangements

The economics of the upstream petroleum business is complex and dynamic. Each year anywhere between 25-50 countries in the world offer license rounds, 20-30 countries introduce new model contracts or regulations, and nearly all countries revisit their tax laws during their annual budgetary process. Typical (or "average") country or regional contracts do not exist, and the terms and conditions of most contracts are proprietary, and at best, partially observable.

There are more fiscal systems in the world than there are countries because

- Numerous vintages of contracts may be in force at any one time,
- Countries typically use more than one arrangement in license rounds, and
- Contract terms are often negotiated and renegotiated as political and economic conditions change, or as the perception of prospectivity in a region change.

The information used to analyze fiscal regimes is often incomplete and uncertain because

- Terms and conditions of contracts are considered proprietary,
- Field specific information is often not available, and
- Changes in the external environment are tied to fiscal terms in various ways.

As a country's domestic production declines or flattens, the oil and gas companies within the country will look at foreign exploration opportunities to expand operations and increase growth potential. Companies compete to obtain licenses to explore and develop reserves from countries that compete to attract foreign investment and technology. Competition exists between companies, countries, and regions to attract foreign investment. As profits fall or rise in one geographic region or play, companies shift their funds and/or revise their business models and strategic objectives to capture the best rate of return consistent with their risk-reward strategy.

11.2. Contract Types

In order to convert mineral assets into financial resources, a government must attract investment capital to explore for, develop, and produce its natural resources. Many styles of contracts govern the arrangements between Host Government (HG) and International Oil Company (IOC) engaged in E&P activity. These arrangements have evolved over many decades in response to political, economic, technical, and geologic conditions. Today, there are essentially four basic types of E&P contracts:

- Concessionary (Royalty/Tax),
- Contractual (Production Sharing Contracts),
- Participation Agreements, and
- Service Agreements.

Each arrangement provides for different levels of control to the IOC, for different compensation arrangements, and for different levels of NOC involvement. Many contracts share elements from one or more categories.

Royalty/Tax systems allow the title to hydrocarbons to transfer to the IOC, while under a contractual system, the HG retains title to the mineral resources and maintains closer control of the management of the operation. Participation agreements create a joint venture between the HG and IOC through the NOC as partner. In a service agreement, a company agrees to perform a service for a monetary payment. Service agreements rarely include a right to share in production, and outside Mexico and the Middle East, are not popular for E&P activity. Royalty/Tax and Production Sharing Contracts (PSC) are the most common agreements in use today.

11.3. Exploration Market

The market for exploration acreage is competitive, finite, and nonhomogenous. Governments offer exploration acreage through formal competitive bidding rounds or through individual negotiation. The market for acreage follows supply and demand fundamentals with demand expected to follow the price of oil and the cash flow position of industry. The supply of acreage has increased over the past two decades as countries outside the Middle East have opened up new areas for exploration, especially on their continental shelves. The amount of acreage available for E&P is also finite and determined through national jurisdiction. The quality of acreage is not homogeneous, however, and different regions have different "prospectivity," depending upon geologic, fiscal, legal, and political factors.

11.4. Capital Market

Governments compete for E&P capital in much the same way that companies compete to acquire exploration acreage. Governments compete on a regional and (to some extent) international basis with other countries to attract capital, while companies compete on a regional and international basis with other companies, and increasingly, NOCs to acquire acreage. Investment capital flows to regions under the influence of complex economic, historic, political, and strategic factors governed by perceptions of risk and return and constrained by the objectives of the contractor and the prospectivity of the country. When countries compete, the share of economic rent may become depressed, while when companies compete, profit margins are likely to be impacted. Countries may offer favorable terms to companies to compensate for other factors, such as an unattractive investment environment or high political risk, or may be inclined for political reasons to favor strategic partnerships for geopolitical influence.

12. FISCAL SYSTEM FUNDAMENTALS

12.1. Economic Rent

Economic rent refers to the difference between the market price of a commodity and the opportunity cost in supplying the commodity (Dam, 1976; Johnston, 1994; Seba, 2000), or as the difference between the value of production and the cost of extraction, where the cost of extraction includes the exploration, development, and operating costs; the cost of capital; and a risk premium (Barnett and Morse, 1963; Kemp, 1987; Mommer, 2002a).

Governments attempt to capture as much economic rent as possible through the terms of the fiscal regime and taxation structure. There are many ways to extract rent, but none of the arrangements is inherently more profitable than any other, and in theory all petroleum arrangements can be made fiscally equivalent by adjusting the contract parameters. Once the requirements of the structure for the fiscal regime and local law have been identified, the negotiating skills and strategies of the parties involved (oil company and host government) become a significant determinant of the final contract terms. Oil companies were once in a privileged position negotiating with inexperienced foreign governments; today host countries are experienced, knowledgeable, and well-educated regarding what the market will bear.

12.2. Oil Company and Host Government Objectives

Countries compete to attract foreign investment and seek to maximize the wealth of its natural resources, while companies seek to build equity and maximize shareholders' wealth. Most countries compete regionally, while oil companies and NOCs compete globally. The motivation of any development agreement is the generation of capital and the development of infrastructure. Governments have an obvious economic interest to obtain the most beneficial terms, but also must make adequate account of negotiated provisions to constituents. Host governments negotiate agreements to accomplish objectives, such as provide a fair return to the state and industry, create healthy competition and market efficiency, and maximize the revenues related to production.

12.3. Fiscal Regime

The fiscal regime of a country refers to the policy framework and legal basis for taxation or production sharing that governs E&P blocks. The fiscal regime governs the negotiation between IOC and HG in the determination of an E&P contract.

Fears of exploitation, pollution, loss of national pride, and tradition stem from the treatment of host countries at the hands of IOCs in the past. Likewise, IOCs harbor a fear of expropriation and privatization of their investment which stem from similar incidents occurring in the past.

Under a Royalty/Tax system, the contract holder secures exploration rights from a private party or government for a specified duration, and development and production rights for each commercial discovery, subject to the payment of royalty and taxes. The IOC bears the full cost and risk of E&P activity, and if no oil is found, the contractor does not receive reimbursement for expenses. The earliest concessionary agreements consisted only of a royalty. As governments gained experience and bargaining power, royalties increased, and various levels of taxation were added. Today, modern concessionary systems employ numerous fiscal devices and sophisticated formulas to capture rent.

Under a PSC, governments usually make contracts under powers granted by general petroleum legislation and frequently negotiate based on a model contract. Ownership of the resource remains with the state, and the IOC is contracted to explore and develop the resource in return for a share of the production. The IOC bears the sole cost and risk of E&P activity, and only if exploration is successful, will be reimbursed for its cost from a share of production. An agreed share of net revenues, referred to as cost oil, is made available to the contractor for recovery of exploration, development and operating costs. The remaining hydrocarbon revenue, called profit oil, is split according to a negotiated formula. The fiscal parameters of a PSC may be subject to bidding or negotiation, and to account for various forms of uncertainty, sliding scales are frequently applied.

12.4. A Brief History of International Arrangements

The earliest international petroleum arrangements were concessions granted at the turn of the century (Blinn et al., 1986). The earliest provisions were highly favorable to the oil company and included

- Very large contract areas,
- Long concession periods,
- No participation by the host country,
- No production requirement, and
- No relinquishment requirement.

The archetypal Middle Eastern concession was obtained by William D'Arcy from the Shah of Persia in 1901. For a $100,000 bonus, $100,000 in stock in his oil company, and a 16% royalty, D'Aray received exclusive oil rights to 500,000 square miles of Persia for the next 60 years. Other concessions in Saudi Arabia, Abu Dhabi, Kuwait, and Oman generally followed the same format (Smith et al., 2000). These concessions did not obligate the companies to drill on any of the lands or to release territory if exploration and drilling was not undertaken. The host country also had no right to participate in managerial decisions and many early concessions freed the companies from all tax obligation. Some later concessions granted in the region were even less favorable, providing a royalty calculated as a flat rate per ton rather than as a percentage of the value of the sale price of production.

In the mid-1950's many Middle Eastern contracts were renegotiated and changes in the concession format evolved into total or partial ownership by the host government on a joint venture basis. Changes in taxation were also introduced. Hybrid fiscal regimes combining royalties with tax structures became more common. OPEC was founded in

1960 and sought to control production and prices by changing the balance of bargaining power in favor of the producing countries and away from the majors. Renegotiation became the vehicle for a substantial restructuring of the traditional concessionary system. NOCs were set up to participate in oil ventures as a vehicle for the government to control and have greater influence of their natural resources. The level of state participation was initially low, but increased with the passage of time.

In 1966, Indonesia negotiated the first production sharing agreement in response to criticism and hostility toward existing concessionary systems. A number of other countries followed Indonesia's lead.

Risk Service (RS) contracts became increasingly popular through the 1980s. In a RS contract, the contractor takes on all of the risk and expense of exploring and developing production, and in return is paid a negotiated fee per barrel produced. In the 1980's, petroleum arrangements tended toward rate of return based profit sharing contracts. Throughout the 1970s and 1980s, governments began experimenting with more direct involvement with production. It has been reported that HGs have tended to take larger shares of gross profits after the formation of OPEC, and especially, after the price rises of 1973 and 1979 (Rutledge and Wright, 1998). In the 1990s, countries focused attention on international competitiveness and fiscal incentives, and as we move into the 21st century, several countries are re-evaluating their fiscal terms in light of sustained high oil prices.

12.5. Fiscal Systems Vary Over Time, Country, Region, and Field

Governments respond to market forces in setting terms and conditions for their acreage and continually "test" the market, in attempting to renegotiate contracts or revise petroleum legislation, and then re-adjusting the terms and negotiation tactics depending on investor reaction. In countries with high prospectivity or unstable political environments, it is a continuous game of give-and-take.

Countries make use of a broad range of tax and nontax instruments to collect revenue from the oil and gas sector, and as one would expect, the strictest fiscal regimes tend to be in countries that offer the most attractive geological prospects, combined with fiscal, legal, political, and macroeconomic stability. Countries that have a strong reserves base and produce more oil than they consume are generally expected to have tighter fiscal policies than importing countries with a moderate reserve base. In some countries, a single fiscal system applies to the entire industry, while in other countries, a variety of fiscal systems may exist. At any point in time, many different contract types are usually in force. Every field in the world is unique in terms of its geologic characteristics and hydrocarbon chemistry, but also in terms of the conditions that lead to a successful E&P contract. Many factors that influence perceptions and negotiation strategies are often unobservable or difficult to quantify.

13. FISCAL ELEMENTS

13.1. Concessionary Systems

In its most basic form, a concessionary system has three components:

- Royalty,
- Deduction, and
- Tax.

The royalty is normally a percentage of the gross revenues of the sale of hydrocarbons and can be paid in cash or in kind. Royalty represents a cost of doing business and is thus tax-deductible. Deductions include operating expense (Opex), depreciation of capitalized assets, amortization, etc. The revenue that remains after the fiscal cost is called taxable income:

$$\text{Taxable Income} = \text{Revenues} - \text{Fiscal Cost},$$

where,

$$\text{Fiscal Cost} = \text{Royalty} + \text{Opex} + \text{Depreciation}.$$

The definition of fiscal costs is described in the legislation of the country. Royalties and operating cost are normally expensed in the year they occur. Depreciation is calculated according to the tax legislation.

Profit is determined as:

$$\text{Profit} = \text{Revenue} - \text{Fiscal Cost} - \text{Tax}.$$

The government's share of profits, in percentage terms, is called the government "take." Take can assume many forms, depending on the time frame of the analysis and the definition employed. Non-profit related elements of government take, such as royalties and bonuses, are "regressive" in the sense that they are an up-front cost required prior to production. The further downstream from gross revenues a government levies taxes, the more "progressive" the system becomes. A simple bonus bid with no royalties or taxes is an example of a fiscal system where the government captures economic rent at the time of the transfer of rights. Royalties provide a guarantee that the government will benefit in the early stages of production. At the opposite extreme is a system based on the taxation of profits, where a government takes only if the venture is profitable. Most systems fall in-between the two extremes (Gao, 1994; Kemp, 1987; Mikesell and Bartsch, 1971; Mommer, 1999).

13.2. Contractual Systems

In a production sharing contract, exploration is performed by the operating company at its own risk and can only be recovered from future production. This feature is not unlike the risk associated with normal exploration, but the difference arises in how expenditures are recovered if reserves are found and the manner in which reserves are split between the host country and the company. If petroleum reserves are discovered, they are almost always owned by the host government, but the production is split between the host government and the company according to a negotiated formula.

The production sharing agreement divides production between the government and the contractor after allowing a portion for cost recovery. A PSA typically imposes a lower income tax and royalty, and in its most basic form, has four components:

- Royalty,
- Cost Recovery,
- Profit Oil, and
- Tax.

The oil company pays a royalty on gross production to the government and is then entitled to a pre-specified share of production for cost recovery. The remainder of the production is shared between government and the oil company at a stipulated amount. The oil company has to pay income tax on its share of profit oil.

Two basic service contracts exist, the “full risk” service contract and the “normal” service contract. In a normal service contract, the company agrees to perform a certain amount of exploration work in a specified area. The oil company is reimbursed for cost incurred and may be paid a bonus if it discovers reserves. In a full risk service contract, the exploration and development expenditures are generally converted to a loan which is repaid in cash installments based on cash flows from all or a specified portion of production.

14. LICENSING AND NEGOTIATION

An E&P contract is a legal instrument written between two parties – an oil company and a mineral rights owner – that describe the terms and conditions of exploration and production. The terms and conditions of the contract are negotiated to satisfy *each* party, are written *before* exploration has occurred, and hold for *all* fields discovered on the block that are declared *commercial* within the exploration period of the contract. Geologists and engineers estimate the geologic potential and hypothesize field sizes that may reside within the contract area based on preliminary "data packages." Basic seismic data is usually available from the government for a fixed fee, and a prospective bidder may have proprietary data on the block or nearby acreage. From a hypothetical field size distribution, the bid parameters and work program of the contract is determined.

The mineral rights owner is frequently a sovereign nation and the process begins when the HG announces a license round and divides prospective acreage into contract areas (license blocks). The IOC evaluates exploration and development scenarios for individual blocks based on information provided by the HG and other sources. Technical and commercial bids are prepared consistent with the prospectivity, strategic objectives, and capital budget of the firm:

- Technical bids specify the work commitment W to be performed, describing the seismic work (in kilometers), the number of wells to be drilled (by type and total footage), and/or the total expenditures to be spent within the block.
- Commercial bids specify the biddable parameters of the fiscal regime F which will govern operations if exploratory activities find commercial quantities of resource.

The work commitment is a certain event, while the terms of the fiscal system only hold if a discovery is declared commercial.

To determine the bid parameters, the IOC conducts scenario ("what if") analysis to assess the risk-reward criteria of the bid. The work program is taken at the sole risk and cost of the IOC, and if exploration is unsuccessful, the HG does not reimburse the IOC for cost expensed. If the exploratory program finds hydrocarbons, then the size and complexity of the field(s) within the block, as well as a number of other factors, such as existing infrastructure, oil quality, geologic complexity, fiscal terms, operating conditions, etc., will determine if the field is commercial. If block B has a hypothetical field distribution $\{ f_1 ,\ldots, f_k \}$, with field f_i having an estimated present value[11] of $PV_i(F,W)$ and probability of discover, $p_i(W)$, then the present value of the block is $\Sigma p_i(W)PV_i(F,W)$. The IOC will

[11] The value of a petroleum property – whether producing or unexplored – is typically computed as the discounted cash flow of a projected cash flow stream. The discount rate determines the relative weight to be given to each flows received at different times and depends upon the property type and owner. Typically, properties developed by major U.S. producers employ discount rates in the range 8-14%, but smaller producers or projects in foreign lands, may be deemed riskier and require a higher discount. Expectations of price and cost fluctuations and other non-diversifiable sources of risk (such as political risk) also influence the selection of the discount rate.

select values of F and W such that the present value of the work program is less than the expected reward of discovery, $PV(W) < \Sigma\, p_i(W)PV_i(F,W)$.

The HG compares the bids received to determine the most favorable contracts based on the proposed work commitment, (W_i, F_i), $i = 1, \ldots, q$; the technical standing, experience, capabilities, past business practices, and financial position of the IOC; and previous experience and success in exploration in the area or similar areas.

The work program is usually easy to evaluate since it refers to the seismic acquisition, drilling requirements, and/or total expenditures to be made. The present value of the work program is computed and used to compare contractor commitment. Evaluation of the fiscal terms is more complicated, since it is based on conditions that are uncertain (discovery, commerciality, reserve size, field characteristics, etc.) as well as specific assumptions of each bidder. Host governments attempt to balance the tradeoffs involved in selecting a large work commitment and poor fiscal terms versus a small work commitment but more favorable fiscal parameters. In negotiation, the HG and IOC must achieve a balance between maximizing reward and minimizing risk. The HG will need to weight its desire to maximize short-term revenue against any deterrent effects this may have on investment. The IOC will need to weight the risk capital against the reward potential subject to its capital budget constraints and strategic objectives.

The IOC(s) with the most favorable terms are short listed for further negotiation. The HG and IOC negotiate the final terms of the contract (the work program and fiscal regime) such that the economic, development, and socioeconomic objectives of each party are satisfied. Terms are suggested by the contractor to enhance their objective functions. These terms are evaluated by the host government and approved, rejected, or countered. The process is continued until either a mutually agreeable set of terms is determined, in which case a deal is made, or agreement cannot be reached and the deal is dead or negotiation resumes at a later date. After both parties sign the contract, the terms and conditions are generally not subject to re-negotiation unless by mutual consent. Unilateral action (say, by government decree) is a mild form of nationalization, and although not necessarily illegal by international law, is considered bad business practice.

15. FACTORS THAT IMPACT E&P CONTRACT STRUCTURE

15.1. Categorization

Many factors influence the type of contract a country adopts in E&P activity. Many more factors impact the terms and conditions of the contracts that are actually negotiated. To understand the variations that are possible, it is useful to consider general classification categories and then enumerate factors believed to be relevant (Table A.26). The factor lists are not exhaustive, and usually reflect data availability, analyst preference, economic fundamentals, and other factors.

15.1.1. Geologic Prospectivity: Geologic prospectivity refers to the capability of an area to host commercial quantities of hydrocarbons. There are many different and independent factors that indicate geologic potential and prospectivity, including proved reserves, proved and probable reserves, undiscovered resources, reserves additions, current production, R/P ratio, and average field size.

15.1.2. Technical Prospectivity: Technical prospectivity refers to the economic and geologic conditions that characterize E&P activity on a field or area-wide basis, such as delineations according to onshore/offshore, frontier/mature, shallow/deep/ultradeep water, deep/ultradeep drilling horizon categories, etc. This is a broadly defined category and includes attributes such as finding and development costs, oil company participation, production maturity, and many other variables.

15.1.3. Country Prospectivity: Country prospectivity describes the economic and political conditions which impact a country's bargaining position in contract negotiation. Many factors characterize country prospectivity, and some of the major factors include: GDP per capita (economic strength), oil revenue per GDP (oil dependence), oil price risk premium (oil dependence), foreign direct investment (economic strength), E&P investment capital (investor interest), import/export status (bargaining position), macroeconomic stability (economic strength), company type (bargaining position), corruption index (bargaining position), economic system, regional prospectivity, country history, IOC participation, investment climate, political risk, degree of competition, and number of successful producing projects.

15.1.4. Geopolitical Prospectivity: Geopolitical prospectivity refers both to the political risk involved with investment, such as repatriation, nationalization, supply disruption, war, riots, contract renegotiation, and changing laws, and the political aims of the government leadership such as strengthening political relationships with a country through economic cooperation, positioning NOC as a geopolitical tool, etc.

15.1.5. Legal Prospectivity: Legal prospectivity refers to a country's respect for the rule of law, legislative complexity, legislative maturity, stability of contract terms, and the nature and frequency of changes in the petroleum legislation.

15.2. Factor Description

For a general category, each factor may be proxied by one or more variables, with the selection governed by data availability, user preference, economic theory, or other conditions. Unobservable factors need to be inferred, usually have a higher degree of uncertainty, and are less reliable in application. All proxies are noisy and do not necessarily provide a correlation between a factor and measure.

15.2.1. Reserves Additions: Proved reserves can be augmented through exploration and development of new discoveries, through technological improvements, as well as the existence of more favorable economic conditions. Reserves additions represent the change in proved reserves over a period of time, and are linked in an uncertain manner, to the amount of investment.

15.2.2. R/P Ratio: The reserves-to-production (R/P) ratio is a measure of the potential availability of a resource over time. The R/P ratio describes the proved reserves inventory of an entity (e.g., company, country, region, world) at a specific point in time divided by the production rate at the same time. The R/P ratio is normally interpreted as the number of years that the existent reserves base can sustain the current level of production.

The uncertainty of R/P is small, since both the numerator and denominator term are reasonably well known quantities, but the ratio itself contains less information than it might suggest. For example, an oil producing country with low reserves (R) but even lower production (P) may exhibit a relatively large R/P (e.g., Italy, Tunisia) which does not correlate to prospectivity. In other cases, R/P may increase because of production decline; e.g., the U.S. R/P ratio increased from 7.7 in 1993 to 11.3 in 2003 primarily because U.S. production has declined by about 1 million BPD through the decade, not because of advances in discovery. Countries with high R/P may or may not be exporting countries.

15.2.3. Finding and Development Cost: The cost to find and develop oil and gas is one of the most common business performance measures in evaluating companies and comparing oil-producing regions. Unfortunately, simple numerical measures usually do a poor job of adequately capturing the complexity of the E&P process. Finding and development (F&D) costs vary over time, by company, country, and region, and this hierarchy dictates the manner in which F&D costs are categorized. It is generally not possible to trace expenditures in a direct fashion from exploration to field development. Finding and developing costs for a country are frequently computed as a weighted (or simple) average of all (or a sample) of the companies operating in the country.

15.2.4. Country E&P History: A government's track record can be measured by a number of proxies, such as the number of licensing rounds it has performed, years of production, the number of IOCs involved in a license round and/or production, competency of the country to administer a tax system, legislative maturity, investment climate, etc. Many of these measures are subjective indices which may or may not provide a useful descriptive proxy.

15.2.5. Industry Structure: IOCs may be classified in terms of their size via reserves base or market capitalization, operational areas, degree of vertical integration, or any of several other measures. NOCs may be classified in terms of their OPEC membership, demand or supply nature, operational areas, or economic strength.

15.2.6. Economic Strength: The economic strength of a country and the experience of the NOC provide an indicator of the relative bargaining position of the country in negotiation with the IOC. Economic strength can be measured in absolute (e.g., GDP) or relative terms (GDP per capita).

15.2.7. Economic Growth: Economic growth in oil producing nations increase the country demand for oil which can be satisfied by local production. Nations whose oil exporting sector is a major component of their GDP are typically led by the expansion of the sector. High oil prices create an inflow of oil demand revenue increasing GDP growth.

15.2.8. Oil Price Risk: If a government obtains substantial revenue from oil production and exports, changes in oil prices will have an impact on revenues generated (Table A.27). Oil price risk is the contribution that changes in oil prices makes to the variance in GDP – the greater the contribution, the greater the premium.

15.2.9. Oil Intensity: Oil intensity is defined as the consumption of oil per $1000 of GDP. Net oil trade as a percent of GDP is another potentially relevant indicator, since as the proportion of oil revenues increases, the host country is likely to want increasing control over this part of their economy.

15.3. Fiscal Systems Are Governed by Multiple Trade-Offs

Fiscal systems are governed through multiple trade-offs. If a region has "significant" prospectivity, and the legal, fiscal, and geopolitical factors are "acceptable," then the region should be successful in attracting investment into the E&P sector. If the region observes declining technical prospectivity, then enhanced legal, fiscal, and geopolitical factors may be employed to balance the system. If a frontier region does not draw IOC interest, the HG and IOC will likely pursue a "weak fiscal system, large work program" policy. For a region with recent discoveries and perceived good prospectivity, a "strong fiscal system, small work program" policy would be more likely to prevail. Perceptions and expectations play an important role in negotiation.

The impact of unobservable factors is difficult to ascertain, but are believed to be just as relevant. Contract negotiations may take place over one or more years, and during this time, E&P activity may occur in the region and influence the perceptions of the negotiating team while the global economic environment may improve or deteriorate. If a series of dry wells are publicly announced, or an initial exploratory well is a spectacular success, this may impact the terms and conditions of negotiation. The historic and personal relationships that exist between IOC and HG personnel are additional factors that influence the terms and conditions that are ultimately determined.

The relationship between the factors that describe and characterize a fiscal system and the fiscal terms observed in signed contracts follow readily discernable hypothesis, but the veracity of the results need to be continually probed and questioned. Factor relations are tested by asking the question: "How do we expect a fiscal system to be perceived by an investor for a factor with a 'high' versus a 'low' value while holding 'all other factors constant'?"

- A region with a high geologic prospectivity, as measured by proved reserves or production rate, will likely have tougher terms than a region with a low geologic prospectivity, for all other factors constant.

- Countries that are net exporters will likely set tougher conditions on the terms and conditions of exploration relative to net importing countries. A region with a high F&D cost will likely offer better terms than a low F&D cost region.

- Frontier acreage is expected to offer better terms because of the additional risk and uncertainty associated with exploration, while for a mature region (as measured, say, by the number of years past peak production), the sign is likely to be ambiguous – the potential for large discoveries is reduced, but this may be balanced by greater regulatory certainty and infrastructure and service networks that will keep development costs down[12].

- If a government obtains substantial revenue from oil production and exports, changes in oil prices will have an impact on revenues generated and may impact fiscal terms, both current and future contracts, but the direction of the impact is difficult to ascertain. It is expected that countries with a high oil price risk premium will have more lenient terms, for other factors constant, and as the proportion of oil revenues increase, the host country may desire to exert greater control.

- The size of a company, its economic strength, international experience, and strategic objectives play an important role in contract negotiations. The role and power of the NOC, local/global experience, participation requirements, and relationship with the IOC are additional factors that influence contract terms.

- The bargaining position of a company is directly correlated with its size and experience. NOCs bargaining position is related to its economic strength, experience, and other country-specific characteristics.

[12] For example, the U.S. Gulf of Mexico is a relatively high-cost production area at $10-15/BOE (compared to $2-5/BOE Middle East production) with a deepwater environment that is one of the harshest in the world and environmental and safety regulations regularly enforced. On the other hand, the GOM also has a well-developed infrastructure, a host of well-positioned professional service companies, reasonable royalty and tax requirements, and creative incentive programs that continues to make the region attractive to investment.

- Royalty/Tax systems are the oldest in the world, and due to political, historical, and other conditions, if a country has been under such a system for a length of time, momentum may maintain the framework with adjustments being made to the terms of the contract. PSCs are likely to be the preferred contract type in new acreage rounds.

16. CONTRACT SELECTION

16.1. Data Source

The type of contracts countries use to govern their E&P industry are observable features obtained either by examining a country's petroleum legislation or by reviewing the contracts that are signed in a license round. The principal source of information regarding petroleum laws and contracts is published by Barrows (www.barrowscompany.com). Barrows divides the world into six regions and charges $7,900/region ($2,950/region renewal price) for a listing of laws and contracts concluded through the year. A summary of typical model oil contracts is also available in a Petroleum Concession Handbook for $5,400 ($2,700 renewal). An overview of countries petroleum laws and investment climate, tax, and model contracts can be purchased for $6,000. Contracts and participation agreements in which governments have formed joint ventures are also available in various other, usually dated, publications; e.g., (Barrows, 1983; Barrows, 1994; Johnston, 1994; Mikesell, 1984; Mommer, 2002b; Taverne, 1994; Smith et al., 2000; Wood, 1993).

16.2. Categorization

There are many ways to characterize and describe the choice of contract a country employs. The most accurate approach is a comprehensive historic review of the country's economic, political, and geologic prospects. Another approach is to select a few distinguishing features that can be used as factor descriptors. The former approach is best suited for a country study, but is usually not appropriate for a regional or global analysis. The factor approach has much to recommend it since it is direct, relatively straightforward, and provides a suitable framework for discussion. The main weakness is that the assessment is only capable of incorporating a few distinguishing factors, and often in a simplistic, causal manner. The factor approach is thus limited in its ability to capture all the variability that is observed, and so a carefully defined framework is often necessary in analysis. Some examples of classification systems illustrate their application and pitfalls.

16.2.1. One Factor: One of the simplest factors to consider in contract selection is the development status of the country (Table A.28). Industrialized countries have tended to rely on Royalty/Tax systems, while PSCs are the primary choice for many developing countries, especially those opening up new areas for exploration or revising their petroleum legislation.

The political system of a country may be used to classify fiscal regimes according to political and institutional features; e.g., mature democracies, factional democracies, paternalistic autocracies, predatory autocracies, or reformist autocracies (Table A.29). Economic systems are generally linked with political systems, but may also be considered separately. Bunter (2002) applies a regional classification as follows (Table A.30):

- *Industrialized*. Developed economies are classified as laissez faire (lack of government intervention) and dirigiste (directed economies). In laissez faire economies, there is a strong rule of law with the terms/conditions of E&P generally favorable. In dirigiste economies, the state is viewed as protection against business and state oil companies as proprietor and custodian of the nation's resources. In dirigiste economies, access may be limited to the NOC, and if access is open, the fiscal terms are expected to be more stringent. In both developed and dirigiste economies, Royalty/Tax systems are standard; PSCs and resource rent tax (RRT)-based systems are rare.

- *OPEC*. In "rich" OPEC countries, there is a powerful NOC and the IOC serves as a contractor under Service Contracts with limited access. The E&P terms are tough with little upside potential. In "less rich" OPEC countries, the NOC is less powerful and foreign investment is required. E&P contracts in these countries are more conducive to investment, but the risk premium is also higher.

- *FSU*. Russia and FSU countries have generally been resistant to foreign partners, and in recent years, Russia has made the decision to consolidate/monopolize its energy empire which will further restrict foreign investment. The rule of law is still not firmly established in the region, and corruption levels are similar to many less rich OPEC countries. The presence of significant oil and gas resources means that E&P terms are tough. FSU countries with good prospectivity such as Kazakhstan, Uzbekistan, and Turkmenistan have been more open to foreign investment, at least in their initial license rounds, but their close geographic proximity to Russia and China is likely to lead to more limited access for western investment in the future. FSU countries with modest or low prospectivity such as Tajikistan, Kygisistan, Ukraine, and Belarus have more favorable E&P terms. A variety of systems have been employed throughout FSU countries.

- *Africa*. In Africa, about half of the countries rely on PSCs, and the other half a profit-based Royalty/Tax system with a resource rent tax. Periodic crises keep the risk premium in several African countries high.

- *Asia*. In Asia, PSCs are widespread, due to Indonesia's influence in creating the first PSC in 1966. Only a few countries in Asia apply RRT-based systems.

16.2.2. Two or More Factors: Countries that have a strong reserves base and produce more oil than they consume are expected to have tighter fiscal policies than importing countries with a moderate reserve base. A two-factor model using "economic strength" and "oil supply balance" under two subcategories (economic strength and supply balance) is shown in Table A.31. Production Sharing Contracts are applied under all combinations of conditions. Joint ventures find application in weak exporting countries and in strong importing countries. Risk contracts tend to be applied in economically weak oil importing countries, and service contracts in strong exporting countries (e.g., Saudi

Arabia, Kuwait), although Mexico also employs service contracts but is not a strong exporter. Multiple factors can be adopted in a regression modeling framework to help explain contract type and terms, but the weak correspondence, noisy proxies, and the multiple correlating factors imply that analytic models will at best only partially explain the variability that is observed.

17. CONTRACT TERMS, CONDITIONS, COMPARISONS

17.1. Negotiating Contract Terms

The terms and conditions of a contract are negotiated between two parties, at a specific point in time, and for specific acreage. The parties to the negotiation have a unique history; with different experiences, strengths, weaknesses, and objectives; and their own perception of the prospectivity of the region and investment risk. The confluence and interaction of these factors, many of which are unobservable and not conducive to quantitative analysis, will mean that the determination of a primary factor set to assess and compare contract terms and conditions is unlikely to be completely successful. Contracts need to be examined on an individual basis, and if "trends" and "patterns" in a country or region are to be believed, a careful analytic framework needs to be developed.

17.2. Measurement Issues

A number of measurement problems exist in regard to data acquisition and assessment. The terms and conditions of contracts in many countries are governed by nondisclosure clauses, and thus, are generally unobservable. Under PSCs, governments will make contracts under powers granted by general petroleum legislation and negotiate from a model contract. Model contracts are publicly available or for purchase, but they do not represent the final negotiated contract. Model contracts are merely the starting point of negotiation, and thus use or comparison of a model contract will necessarily introduce bias. Signed contracts are the ideal data instruments to employ, but they can usually only be acquired at a significant fee or through private contact. To ensure a representative sample for a country, region, or period of time, several contracts should be examined. Mixing model and signed contracts is not considered good methodological practice, but may be necessitated because of sparse data availability.

A number of additional assumptions and inferences are required in assessment which complicates and distorts the analysis. An E&P contract is composed of numerous terms and conditions which may be difficult, if not impossible, to compare on an individual basis, and it is the collection of terms (in total) that "make" the contract. If the structure of contracts are stable, we could examine individual terms (royalty, tax, profit oil, etc.) and map how they change over time, across firms and regions. The problem with this approach is that multiple terms can change in different directions, and it is really the aggregate of all the contract changes that impact project economics and not the change in any individual term.

Fiscal terms are frequently multidimensional and nonlinear, and so in general, one-factor models will not suffice. An alternative method is to attempt to characterize the fiscal system in one (or a few) numerical measures that describe the impact of the system. "Take" is a metric that is frequently used for this purpose.

17.3. Take Measure

Take is the most common method to compare fiscal systems, and like many other (one-dimensional) metrics, is frequently misapplied and misunderstood (Johnston, 2002). Data on government take for projects and countries are readily available, but their calculation and interpretation is subject to a high degree of uncertainty which is frequently ignored or miss-specified.

There are two methodological approaches to the computation of take. We can apply "standard field conditions" to a given fiscal system and assess the fiscal regime indirectly, or we can attempt to compute the expected value of take ex-ante under "specific field conditions" that are known or expected to hold for the field. Strengths and weaknesses are associated with each approach.

17.3.1. Standard Field Conditions: Under standard field conditions, a given field size (e.g., 100, 250, 500, 1000 MMbbl) is evaluated under the fiscal system with respect to a common set of assumptions on oil price, development cost, production cost, etc. relative to a model contract. The common parameters obviate the need to acquire or estimate conditions specific to the development strategy, but introduce bias in the gross approximation. Economic yardsticks such as present value, rate of return, and take. are computed for each field size and then combined according to the specified distribution. VanMeurs uses a point-system to classify fiscal systems into five groups, from "very favorable" (five-point) to "very tough" (one point), while Johnston and others compare undiscounted and discounted take as the system metric (Table A.32). The analysis in both cases is under standard field conditions and is performed *prior to* discovery, and thus, is governed by a large degree of uncertainty. Take computations under standard field conditions are also referred to as pre-discovery assessments.

17.3.2. Specific Field Conditions: Under specified field conditions, take is computed based on a combination of actual and estimated field conditions, using either a signed or model contract. The commercial service providers IHS, Petroconsultants, WoodMacKenzie, and others (Smith, 1993; Kaiser and Pulsipher, 2004) have followed this approach. Commercial databases provide actual and model contract terms, development costs based on engineering estimates, fiscal economics, and related cost statistics. The take statistic under specific field conditions would generally be considered a more accurate and reliable indicator if performed post-discovery. Even under specified field conditions, however, a significant amount of variation is still expected to occur under this approach.

17.4. Many Different Notions of Take Exist

The value, uncertainty, and conceptual basis of take varies throughout the life of a field, beginning from the first stages of assessment in preparation of bid submission, to successful negotiation, discovery, commerciality, production, and eventually, abandonment (Table A.33).

<u>17.4.1. Bid Submission:</u> To determine the parameters in preparation of bid submission, the IOC conducts scenario analysis under different field sizes, fiscal terms and work program commitments. Project economics (and take) are evaluated. All system metrics, including take, are highly uncertain at this point in time because the computation is based on hypothetical conditions supported by limited and often incomplete data.

<u>17.4.2. Negotiation and Award:</u> If the IOC bid submission is accepted, further negotiation will typically occur until a mutually agreeable set of terms is determined. After negotiations are complete and the contract signed, the IOC considers the fiscal terms fixed. The uncertainty associated with discovery and the exogenous environment will determine the uncertainty of the computation.

<u>17.4.3. Discovery:</u> If hydrocarbons are discovered in commercial quantities on the tract, then the take statistic can be computed with a higher level of certainty. The field size distribution is presumably known, the production schedule and development cost can be assessed under known assumptions, and the tax and non-tax instruments were previously negotiated.

<u>17.4.4. Production:</u> With first production, the revenue and cost structure are much better understood, and the take statistic can be computed with a higher degree of certainty. Going forward from first production through depletion the level of uncertainty is expected to decrease, although the stability of the take statistic is dependent on the HG not initiating unilateral changes in the fiscal terms.

<u>17.4.5. Abandonment:</u> At abandonment and under conditions of perfect information, a "look-back" (post-mortem) analysis will determine the exact value of take. In theory, cost and revenues are known precisely, and under known terms of the fiscal system, take can be computed with a high degree of precision.

17.5. Summary of Take Characteristics

- Take is a multidimensional, nonlinear function of variables that are uncertain and unobservable.
- If the terms and conditions of the fiscal system are known, then only at the end of the productive life of a field, when all the production and cost statistics are also known, can the value of take be computed with certainty.
- In all other situations, either because the terms of the fiscal system or the field parameters are not known, or only known under conditions of uncertainty, the level of uncertainty associated with take is governed by the time of assessment (pre-discovery, post discovery) and availability of data.
- Take statistics are uncertain, and depending upon the time of assessment, can be highly uncertain. "Look-back" analysis is rarely performed by industry, since at the end of the life of a field, the value of take has little commercial value.

- Take statistics are provided by various commercial vendors, but use and comparison of the data must be based upon careful assessment and clear knowledge of the assumptions involved.

17.6. Production Sharing Agreement Statistics

Rutledge and Wright claim that a 50:50 split between government and contractor take was considered a fair value before the mid 1970s, and in a study performed by Petroconsultants in 1995 showed that in more than 90% of 110 countries examined, government take ranged from 55%-75%. Mommer and others has shown similar levels of taxation (Mommer, 2002a).

In a 1998 study, Bindemann examined 268 PSAs signed by 74 countries over the period 1966-1998. Each contract was defined with respect to the parties involved in the arrangement (host country, foreign partner(s)), the year the contract was signed, the location (onshore, offshore) of the field, and several other factors.

The royalty rate and cost of oil are reported as the maximum rates while profit oil shares are reported in terms of the minimum and maximum values. Signature and production bonuses are described in U.S. dollars. A summary of the main results are depicted in Table A.34. The results "support" most of assumptions concerning on-shore vs. off-shore regions, import vs. export countries, and regional prospectivity; e.g., royalty rates and signature bonuses for offshore regions and import nations tend to be slightly smaller (more generous) than on-shore regions and export nations, and trends in royalty and maximum cost oil have increased over time.

The results of the study should nonetheless be interpreted with caution, for several reasons:

- The sample set Bindemann employed is not well defined, and its relation to the set of all contracts not described.
- "Model" contracts are frequently used in analysis, but most parameters of model contracts are subject to negotiation or may be biddable, and are not expected to be representative of actual contracts. Significant bias will be introduced into analysis when using model contracts.
- The field characterizations which define the nature of the contracts ("onshore/offshore," "import/export") is not described.
- PSA's employ contracts with sliding royalty scales and cost oil which require knowledge of the (expected) production of the field. Most profit oil shares are also subject to a sliding scale based on output or return which was not considered in the model framework.

Fiscal comparisons are difficult to perform for many reasons, some of which are highlighted in the Bindemann study, but which are common across several other analytic studies.

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APPENDIX

TABLES AND FIGURES

Table A.1

Various Risks Exist in Oil and Gas Investment

Risk Category	Type
Economic	Market Construction Operation Macroeconomic
Geologic	Reserve Production
Political	Regulatory Transfer-of-profit Expropriation/nationalization
Legal	Contract Jurisdictional
Force majeure	Natural disaster Civil unrest Strikes Terrorism

Table A.2

Examples of Integrated Companies Classified According to Geographic Operation

International	U.S. Integrated	Canadian Integrated	Non-North American
BP	Amerada Hess	Husky Energy	BASF A.G.
Chevron	ConocoPhillips	Imperial Oil	BG Group
Exxon Mobil	Murphy Oil	Petro Canada	BHP Billiton
Royal Dutch Shell	Marathan Oil	Suncor Energy	ENI
Total			Lukoil
			MOL
			Petrobras
			Petrochina
			Petro Kazakhstan
			Petroleos Mexicanos
			Repsol
			Sinopec
			Statoil

Table A.3

Examples of Independent Companies Classified According to Size and Geographic Operation

International	Large U.S.	Mid-Sized U.S.	Small-U.S.	Non-North American
Anadarko Petroleum	Cabot Oil & Gas	Berry Petroleum	Harken Energy	Cairn Energy
Apache	Chesapeake Energy	Comstock Resources	McMoRan Exploration	Chaparral Resources
Burlington Resources	Forest Oil	Denbury Resources	Meridian Resources	CNOC
Devon Energy	Newfield Exploration	Energy Partners	PetroQuest Energy	Global SantaFe
EnCana	Noble Energy	Houston Exploration	Remington Oil & Gas	Nelson Resources
EOG Resources	Pogo Producing	Magnum Hunter Resources	Tetra Technologies	Transmendian Exploration
Kerr-McGee	Vintage Petroleum	Stone Energy	W&T Offshore	Venture Production
Nexen	XTO Energy	Swift Energy		Woodside Petroleum
Occidental Petroleum				
Talisman Energy				
Unocal				

Table A.4

Selected National Oil Companies

Country	Company
Abu Dhabi	ADNOC
Algeria	Sonatrach
Angola	Sonangol
Azerbaijan	Socar
Bahrian	Bahrain National Oil (BNOC)
Bolivia	Y.P.F.B.
Brazil	Petroleo Brasileiro SA (Petrobras)
Canada	PetroCanada
China	China National Petroleum Co. (CNPC) China National Offshore Oil Co. (CNOOC) Sinopec
Columbia	Ecopetrol
Dubai	Dubai Petroleum Co. (DPC)
Ecuador	Petroleos del Ecuador
Egypt	Egyptian General Petroleum Corp. (EGPC)
Hungary	Hungarian Oil and Gas Co. (MOL)
Indonesia	Petramina
India	India Oil Corp. (IOC); Oil and Natural Gas Co. (ONGC)
Iran	National Iranian Oil Co. (NIOC)
Iraq	Iraq National Oil Co. (INOC)
Japan	Japan National Oil Co. (JNOC)
Kazakhstan	Kazmunaigaz (KMG)
Korea	Korean National Oil Corp. (KNOC)
Kuwait	Kuwait Petroleum Corp. (KPC)
Libya	National Oil Co. (NOC)
Malaysia	Petronas
Mexico	Petroleos Mexcanos (Pemex)
Nigeria	Nigeria National Petroleum Co. (NNPC)
Norway	Norsk Hydro ASA; Statoil
Oman	Petroleum Development Oman LLC
Peru	Petroperu
Qatar	Qatar Petroleum Corp. (QP)
Romania	Romanian National Oil Co. (Petrom)
Russia	Rosneft; Gazprom
Saudi Arabia	Saudi Arabia Oil Co. (Saudi Aramco)
Trinidad & Tobago	Petroleum Co. of Trinidad & Tobago Ltd. (Petrotrin)
Turkey	Turkish Petroleum Co. (TPAO)
UAE	ENOC
Venezuela	Petroleos de Venezuela SA (PDVSA)

Table A.5

Top 10 Oil and Gas Company Rankings – Oil (2006)

Rank	Company	Reserves (Billion BOE)	Company	Production (MBOE/day)
1	S. Aramco	262.7	S. Aramco	9,830
2	NIOC	132.5	NIOC	4,081
3	INOC	115.0	Pemex	3,754
4	KPC	89.4	PDVSA	2,600
5	PDVSA	77.1	Exxon Mobil	2,571
6	ADNOC	52.6	BP	2,531
7	Libya NOC	28.8	KPC	2,424
8	NNPC	21.2	Royal Dutch Shell	2,333
9	Lukoil	15.9	PetroChina	2,124
10	Pemex	14.8	INOC	2,027

Table A.6

Top 10 Oil and Gas Company Rankings – Oil & Gas (2006)

Rank	Company	Reserves (Billion BOE)	Company	Production (MBOE/day)
1	NIOC	307.2	S. Aramco	10,944
2	S. Aramco	305.6	Gazprom	9,704
3	Gazprom	219.6	NIOC	5,569
4	INOC	135.1	Pemex	4,360
5	QP	128.9	Exxon Mobil	4,347
6	PDV	104.1	BP	4,062
7	KPC	99.4	Royal Dutch Shell	3,918
8	ADNOC	71.6	PDVSA	3,320
9	NNPC	40.2	Sonatrach	3,093
10	Sonatrach	37.9	PetroChina	2,625

Table A.7

Percentage Yields of Refined Petroleum Products from Crude Oil in the U.S., 1964-2003 (%)

	1964	1974	1984	1994	2003
Gasoline	44.1	45.9	46.7	45.7	46.9
Distillate fuel oil	22.8	21.8	21.5	22.3	23.7
Resid, fuel oil	8.2	8.7	7.1	5.7	4.2
Jet fuel	5.6	6.8	9.1	10.1	9.5
Coke	2.6	2.8	3.5	4.3	5.1
Asphalt	3.4	3.7	3.1	3.1	3.2
Liquefied gases	3.3	2.6	1.9	4.2	4.2
Total (%)	90.1	92.3	92.9	95.4	96.8

Source: (EIA, 2005).

Table A.8

U.S. Proven Reserves and Undiscovered Resources

	Oil (Bbbl)			Natural Gas (Tcf)			BOE (Bbbl)		
Region	F95	Mean	F5	F95	Mean	F5	F95	Mean	F5
Alaska OCS	8.66	26.61	55.14	48.28	132.06	279.62	17.25	50.11	104.89
Atlantic OCS	1.12	3.82	7.57	14.30	36.99	66.46	3.67	10.40	19.39
Gulf of Mexico OCS	41.21	44.92	49.11	218.83	232.54	249.08	80.15	86.30	93.43
Pacific OCS	7.55	10.53	13.94	13.28	18.29	24.12	9.91	13.79	18.24
Total U.S. OCS	60.60	85.88	115.13	326.40	419.88	565.87	124.68	160.60	215.82

Source: (USDOI, MMS, 2006).

Note: F95 indicates 95% chance of at least the amount listed, F5 indicates a 5% chance of at least the amount listed. Only mean values are additive.

Table A.9

World Proven Reserves and Undiscovered Resources

	World	United States
Oil	1,293 Bbbl	23 Bbbl
Natural Gas	6,112 Tcf	187 Tcf
Coal	1.08 T tons	0.27 T tons
Oil (Tar) Sands	272 Bbbl	22 Bbbl
Shale Oil	2,570 Bbbl	20 Bbbl

Source: (World Energy Council, 2003).

Table A.10

World Proven Reserves (2004) and Undiscovered Resources (2000)

Region	Oil – Billion barrels (Bbbl)			
	Proven Reserves	Undiscovered Resources F95	F5	Mean
USA	22,446	60,500	94,700	75,600
North America	40,268	67,302	252,190	146,091
FSU	79.4	35,601	225,654	115,985
Middle East and North Africa	743.4	73,286	423,178	229,882
Asia Pacific	35.9	8,726	58,653	29,780
South Asia	5,735	1,032	6,957	3,580
Central and South Africa	102.6	20,090	230,727	105,106
Sub-Saharan Africa and Antarctica	64,529	26,783	124,447	71,512
Europe	14.8	6,339	45,407	22,292
Total World	1,293	239,159	1,376,213	724,228
Region	**Gas – Trillion cubic feet (Tcf)**			
	Proven Reserves	Undiscovered Resources F95	F5	Mean
USA	183	392,600	697,600	526,900
North America	252	413,044	1,051,199	681,399
FSU	1,967	429,164	3,246,740	1,611,262
Middle East and North Africa	2,565	425,371	2,607,896	1,369,933
Asia Pacific	392	109,068	746,044	379,339
South Asia	64	30,518	248,647	119,610
Central and South Africa	386	96,168	1,087,521	487,190
Sub-Saharan Africa and Antarctica	200	83,474	439,436	235,290
Europe	187	44,706	733,412	312,365
Total World	6,112	1,631,513	10,160,895	5,196,388

Source: (Radler, 2005; USGS, 2000).

Table A.11

World Proved Oil Reserves (2004)

Country	At end 1984 Thousand million barrels	At end 1994 Thousand million barrels	At end 2004 Thousand million barrels	At end 2004 Share of total
USA	36.1	29.6	29.4	2.5%
Canada	9.4	10.4	16.8	1.4%
Mexico	56.4	49.8	14.8	1.2%
Total North America	**101.9**	**89.8**	**61.0**	**5.1%**
Argentina	2.3	2.3	2.7	0.2%
Brazil	2.0	5.4	11.2	0.9%
Colombia	1.1	3.1	1.5	0.1%
Ecuador	1.1	3.5	5.1	0.4%
Peru	0.7	0.8	0.9	0.1%
Trinidad & Tobago	0.6	0.6	1.0	0.1%
Venezuela	28.0	64.9	77.2	6.5%
Other S. & Cent. America	0.5	1.0	1.5	0.1%
Total S. & Cent. America	**36.3**	**81.5**	**101.2**	**8.5%**
Azerbaijan	n/a	n/a	7.0	0.6%
Denmark	0.5	0.8	1.3	0.1%
Italy	0.6	0.7	0.7	0.1%
Kazakhstan	n/a	n/a	39.6	3.3%
Norway	4.9	9.6	9.7	0.8%
Romania	1.5	1.0	0.5	◆
Russian Federation	n/a	n/a	72.3	6.1%
Turkmenistan	n/a	n/a	0.5	◆
United Kingdom	6.0	4.3	4.5	0.4%
Uzbekistan	n/a	n/a	0.6	◆
Other Europe & Eurasia	83.2	63.9	2.5	0.2%
Total Europe & Eurasia	**96.7**	**80.3**	**139.2**	**11.7%**
Iran	58.9	94.3	132.5	11.1%
Iraq	65.0	100.0	115.0	9.7%
Kuwait	92.7	96.5	99.0	8.3%
Oman	3.9	5.1	5.6	0.5%
Qatar	4.5	3.5	15.2	1.3%
Saudi Arabia	171.7	261.4	262.7	22.1%
Syria	1.4	2.7	3.2	0.3%
United Arab Emirates	32.5	98.1	97.8	8.2%
Yemen	0.1	0.1	2.9	0.2%
Other Middle East	0.2	0.1	0.1	◆
Total Middle East	**430.8**	**661.7**	**733.9**	**61.7%**
Algeria	9.0	10.0	11.8	1.0%
Angola	2.1	3.0	8.8	0.7%
Chad	-	-	0.9	0.1%
Rep. of Congo	0.8	1.4	1.8	0.2%
Egypt	4.0	3.9	3.6	0.3%
Equatorial Guinea	-	0.3	1.3	0.1%
Gabon	0.6	1.4	2.3	0.2%
Libya	21.4	22.8	39.1	3.3%
Nigeria	16.7	21.0	35.3	3.0%
Sudan	0.3	0.3	6.3	0.5%
Tunisia	1.8	0.3	0.6	0.1%
Other Africa	1.0	0.6	0.5	◆
Total Africa	**57.8**	**65.0**	**112.2**	**9.4%**
Australia	2.9	3.9	4.0	0.3%
Brunei	1.5	1.2	1.1	0.1%
China	16.3	16.2	17.1	1.4%
India	3.8	5.8	5.6	0.5%
Indonesia	9.6	5.0	4.7	0.4%
Malaysia	2.9	5.2	4.3	0.4%
Thailand	0.1	0.2	0.5	◆
Vietnam	-	0.6	3.0	0.2%
Other Asia Pacific	1.1	1.0	0.9	0.1%
Total Asia Pacific	**38.1**	**39.2**	**41.1**	**3.5%**
TOTAL WORLD	**761.6**	**1017.5**	**1188.6**	**100.0%**
Of which OECD	118.7	110.6	82.9	7.0%
OPEC	510.0	777.4	890.3	74.9%
Non-OPEC £	170.6	177.7	177.4	14.9%
Former Soviet Union	81.0	62.4	120.8	10.2%

Source: (British Petroleum, 2005).

* Over 100 years, + Less than 0.05, n/a Not available ◆ Less than 0.05%, £ Excludes Former Soviet Union

Table A.12

World Undiscovered Oil Resources, 2000 (Thousand Million Barrels)

Country	Onshore	Offshore	Total
USA		85.9	
Canada	1.0	1.8	2.8
Mexico	7.7	12.9	20.6
North America			
Argentina	2.0	1.3	3.2
Brazil	*	46.7	46.7
Colombia	5.1	-	5.1
Ecuador	0.8	0.2	1.0
Peru	1.8	1.5	3.3
Trinidad & Tobago	*	0.7	0.8
Venezuela	15.6	4.1	19.7
South & Central America			105.1
Denmark	-	0.1	0.1
Italy	0.4	*	0.4
Norway	-	12.9	12.9
Romania	1.1	-	1.1
United Kingdom	*	6.3	6.3
Europe			22.3
Azerbaijan	0.2	6.1	6.3
Kazakhstan	7.9	13.2	21.1
Russian Federation	66.3	11.1	77.4
Turkmenistan	0.5	6.3	6.8
Uzbekistan	0.1	*	0.1
Former Soviet Union			116.0
Iran	39.7	13.5	53.1
Iraq	45.1	-	45.1
Kuwait	1.6	2.2	3.8
Oman	3.4	-	3.4
Qatar	1.6	2.0	3.6
Saudi Arabia	75.8	11.2	87.1
Syria	1.3	-	1.3
United Arab Emirates	4.4	3.3	7.7
Yemen	3.3	*	3.3
Middle East			229.9
Algeria	7.7	-	7.7
Angola	0.5	14.0	14.5
Cameroon	0.5	1.0	1.5
Republic of Congo	0.2	5.6	5.8
Egypt			
Gabon	0.9	7.3	8.2
Libya	6.6	1.7	8.3
Nigeria	15.4	22.2	37.6
Tunisia	1.7	0.5	2.2
Africa			71.5
Australia	0.2	4.8	5.0
Brunei	0.1	1.7	1.8
China	10.4	1.8	12.1
India	0.8	1.8	2.6
Indonesia	2.2	5.2	7.4
Malaysia	0.1	3.0	3.0
Thailand	-	0.1	0.1
Vietnam	-	*	*
Asia Pacific			32.4
TOTAL WORLD			724.2

Source: (USGS, 2000). Note: ‡Excludes Former Soviet Union, *Less than 0.05%, n/a: Not available.

Table A.13

World Proved Natural Gas Reserves (2004)

Country	At end 1984 Trillion cubic meters	At end 1994 Trillion cubic meters	At end 2004 Trillion cubic meters	At end 2001 Share of total
USA	5.53	4.59	5.29	2.9%
Canada	2.81	1.90	1.60	0.9%
Mexico	2.17	1.94	0.42	0.2%
Total North America	**10.51**	**8.42**	**7.32**	**4.1%**
Argentina	0.67	0.54	0.61	0.3%
Bolivia	0.13	0.11	0.89	0.5%
Brazil	0.08	0.15	0.33	0.2%
Colombia	0.11	0.21	0.11	0.1%
Peru	+	0.34	0.25	0.1%
Trinidad & Tobago	0.31	0.29	0.53	0.3%
Venezuela	1.67	3.97	4.22	2.4%
Other S. & Cent. America	0.24	0.23	0.17	0.1%
Total S. & Cent. America	**3.23**	**5.83**	**7.10**	**4.0%**
Azerbaijan	n/a	n/a	1.37	0.8%
Denmark	0.10	0.12	0.09	◆
Germany	0.31	0.22	0.20	0.1%
Italy	0.25	0.30	0.17	0.1%
Kazakhstan	n/a	n/a	3.00	1.7%
Netherlands	1.90	1.85	1.49	0.8%
Norway	0.56	1.73	2.39	1.3%
Poland	0.09	0.16	0.12	0.1%
Romania	0.21	0.43	0.30	0.2%
Russian Federation	n/a	n/a	48.00	26.7%
Turkmenistan	n/a	n/a	2.90	1.6%
Ukraine	n/a	n/a	1.11	0.6%
United Kingdom	0.73	0.66	0.59	0.3%
Uzbekistan	n/a	n/a	1.86	1.0%
Other Europe & Eurasia	37.87	58.41	0.45	0.2%
Total Europe & Eurasia	**42.02**	**63.87**	**64.02**	**35.7%**
Bahrain	0.21	0.15	0.09	0.1%
Iran	14.02	20.76	27.50	15.3%
Iraq	0.82	3.12	3.17	1.8%
Kuwait	1.04	1.50	1.57	0.9%
Oman	0.22	0.26	1.00	0.6%
Qatar	4.28	7.07	25.78	14.4%
Saudi Arabia	3.61	5.26	6.75	3.8%
Syria	0.10	0.24	0.37	0.2%
United Arab Emirates	3.11	6.78	6.06	3.4%
Yemen	-	0.43	0.48	0.3%
Other Middle East	+	+	0.05	◆
Total Middle East	**27.40**	**45.56**	**72.83**	**40.6%**
Algeria	3.44	2.96	4.55	2.5%
Egypt	0.24	0.63	1.85	1.0%
Libya	0.63	1.31	1.49	0.8%
Nigeria	1.36	3.45	5.00	2.8%
Other Africa	0.56	0.78	1.18	0.7%
Total Africa	**6.22**	**9.13**	**14.06**	**7.8%**
Australia	0.75	1.30	2.46	1.4%
Bangladesh	0.35	0.30	0.44	0.2%
Brunei	0.24	0.40	0.34	0.2%
China	0.89	1.67	2.23	1.2%
India	0.48	0.70	0.92	0.5%
Indonesia	1.70	1.82	2.56	1.4%
Malaysia	1.39	1.93	2.46	1.4%
Myanmar	0.26	0.27	0.53	0.3%
Pakistan	0.52	0.59	0.80	0.4%
Papua New Guinea	-	0.43	0.43	0.2%
Thailand	0.21	0.18	0.43	0.2%
Vietnam	-	0.13	0.24	0.1%
Other Asia Pacific	0.23	0.35	0.38	0.2%
Total Asia Pacific	**7.02**	**10.07**	**14.21**	**7.9%**
TOTAL WORLD	**96.39**	**142.89**	**179.53**	**100.0%**
Of which: European Union 25	3.62	3.44	2.75	1.5%
OECD	15.62	15.00	15.02	8.4%
Former Soviet Union	37.50	58.15	58.51	32.6%

Source: (British Petroleum, 2005). + Less than 0.05, ◆ Less than 0.05%, n/a: Not available.

Table A.14

World Undiscovered Natural Gas Resources, 2000 (Trillion cubic feet)

Country	Onshore	Offshore	Total
USA		419.9	
Canada	15.6	8.9	24.5
Mexico	20.5	28.7	49.3
Total North America			
Argentina	21.8	14.9	36.7
Brazil	0.2	194.2	192.4
Colombia	10.1	-	10.1
Ecuador	0.3	0.2	0.6
Peru	1.9	4.4	6.3
Trinidad & Tobago	1.1	30.7	31.8
Venezuela	60.3	41.0	101.2
Total S. & Cent. America			487.2
Denmark	-	0.8	0.8
Italy	13.0	14.3	27.3
Norway	-	183.0	183.0
Romania	5.4	-	5.4
United Kingdom	*	23.3	23.4
Total Europe			312.4
Azerbaijan	1.6	65.9	67.4
Kazakhstan	38.6	33.7	72.3
Russian Federation	398.0	770.8	1,168.7
Turkmenistan	142.4	65.3	207.7
Uzbekistan	12.8	2.3	15.0
Total Former Soviet Union			1,611.3
Iran	176.2	138.4	314.6
Iraq	120.0	-	120.0
Kuwait	2.8	3.1	5.9
Oman	32.4	1.3	33.7
Qatar	17.5	23.6	41.1
Saudi Arabia	625.1	55.9	681.0
Syria	5.1	-	5.1
United Arab Emirates	28.5	16.0	44.5
Yemen	21.4	0.5	21.9
Total Middle East			1,370.0
Algeria	46.5	2.5	49.0
Angola	1.4	41.3	42.7
Cameroon	1.8	3.8	5.6
Republic of Congo	0.5	16.9	17.4
Egypt			
Gabon	2.8	21.5	24.3
Libya	12.8	8.3	21.1
Nigeria	55.1	68.1	123.2
Tunisia	4.9	2.3	7.1
Total Africa			235.3
Australia	3.4	106.0	109.4
Brunei	0.4	12.0	12.4
China	82.1	3.6	85.8
India	13.1	17.2	30.3
Indonesia	43.4	64.3	107.7
Malaysia	0.4	49.7	50.2
Papua New Guinea			
Thailand	-	4.7	4.7
Vietnam	-	0.8	0.8
Total Asia Pacific			498.9
TOTAL WORLD			5,196.4

Source: (USGS, 2000). Note: ‡Excludes Former Soviet Union, *Less than 0.05%, n/a: Not available.

Table A.15

Bitumen (Tar Sands) and Heavy Oil Technically Recoverable Resources (2003)

Region	Bitumen (Bbbl)	Heavy Oil (Bbbl)
Western Hemisphere	531.0	310.0
North America	530.9	35.3
South America	0.1	265.7
Eastern Hemisphere	119.7	133.3
Africa	43.0	7.2
Europe	0.2	4.9
Middle East	0	78.2
Asia	42.8	29.6
Russia	33.7	13.4
World Total	650.7	434.3

Source: (USGS, 2000).

Table A.16

Oil Production and Consumption Among Primary Producing Countries (2004)

Country	Production (1,000 barrels daily)	Consumption (1,000 barrels daily)	Production-Consumption (1,000 barrels daily)
USA	7241	20517	-13276
Canada	3085	2206	879
Mexico	3824	1896	1928
Total North America	**14150**	**24619**	**-10469**
Argentina	756	393	363
Brazil	1542	1830	-288
Colombia	551	223	328
Ecuador	535	140	395
Peru	93	153	-60
Trinidad & Tobago	155		155
Venezuela	2980	577	2403
Other S. & Cent. America	152	1424	-1272
Total S. & Cent. America	**6764**	**4739**	**2025**
Azerbaijan	318	91	227
Denmark	394	189	205
Italy	104	1871	-1767
Kazakhstan	1295	192	1103
Norway	3188	209	2979
Romania	119	212	-93
Russian Federation	9285	2574	6711
Turkmenistan	202	98	104
United Kingdom	2029	1756	273
Uzbekistan	152	120	32
Other Europe & Eurasia	496	12705	-12209
Total Europe & Eurasia	**17583**	**20017**	**-2434**
Iran	4081	1551	2530
Iraq	2027		2027
Kuwait	2424	266	2158
Oman	785		785
Qatar	990	84	906
Saudi Arabia	10584	1728	8856
Syria	536		536
United Arab Emirates	2667	306	2361
Yemen	429		429
Other Middle East	48	1354	-1306
Total Middle East	**24571**	**5289**	**19282**
Algeria	1933	242	1691
Angola	991		991
Cameroon	62		62
Chad	168		168
Rep. of Congo (Brazzaville)	240		240
Egypt	708	566	142
Equatorial Guinea	350		350
Gabon	235		235
Libya	1607		1607
Nigeria	2508		2508
Sudan	301		301
Tunisia	69		69
Other Africa	92	1839	-1747
Total Africa	**9264**	**2647**	**6617**
Australia	541	858	-317
Brunei	211		211
China	3490	6684	-3194
India	819	2555	-1736
Indonesia	1126	1150	-24
Malaysia	912	504	408
Thailand	218	909	-691
Vietnam	427		427
Other Asia Pacific	184	10786	-10602
Total Asia Pacific	**7928**	**23446**	**-15518**
TOTAL WORLD	**80260**	**80757**	**-497**
Of which OECD	20732	48777	-28045
OPEC	32927		32927
Non-OPEC ‡	35916		35916
Former Soviet Union	11417	3729	7688

Source: (British Petroleum, 2005). ‡Excludes Former Soviet Union

Table A.17

OPEC Production Quotas (Million Barrels per Day)

Country (OPEC Membership)	2000	2001	7/2005 (Quota)	2/2006 (Production)
Saudi Arabia (1960)	8.26	7.58	9.10	9.40
Iran (1960)	3.68	3.43	4.11	3.90
Venezuela (1960)	3.03	2.57	3.22	2.50
Iraq (1960)	2.57*	2.03*	-	1.80
UAE (1967)	2.23	2.00	2.44	2.50
Nigeria (1971)	2.03	1.97	2.31	2.20
Kuwait (1960)	2.10	1.87	2.25	2.60
Libya (1962)	1.41	1.30	1.50	1.65
Indonesia (1962)	1.27	1.10	1.45	0.92
Algeria (1969)	0.81	0.88	0.89	1.38
Qatar (1961)	0.67	0.66	0.73	0.80
OPEC Total	28.06	25.39	28.00	27.85

Footnote: Domestic use only due to U.N. embargo

Table A.18

World Oil Supply Disruptions

Date of Oil Supply Disruption	Supply Duration (months)	Average Gross Supply Shortfall (MBD)	World Production Prior to Disruption (MBD)	Supply Shortfall (%)
Nov. 1956-Mar. 1957 (Suez Crisis)	4	2	16.8	11.9
Dec. 1966-Mar. 1967 (Syrian Transit Fee Dispute)	3	0.7	32.96	2.1
Jun. 1967-Aug. 1967 (Six-Day War)	2	2	35.39	5.7
May 1970-Jan. 1971 (Libyan Price Dispute)	8	1.3	45.89	2.8
Oct.1973-Mar. 1974 (Arab-Israeli War)	6	4.3	57.744	7.4
Nov. 1978-Apr. 1979 (Iranian Revolution)	6	5.6	62.906	8.9
Oct.1980-Jan. 1981 (Iran-Iraq War)	3	4.1	58.338	7.0
Aug. 1990-Jan. 1991 (Iraq Invasion of Kuwait)	5	4.3	60.487	7.1
Jun. 2001-Jul. 2001 (Iraqi Oil Export Suspension)	2	2.1	67.551	3.1
Dec. 2002-Mar. 2003(Venezuela Labor Strike)	4	2.6	68.595	3.8
Mar. 2003-Dec. 2003 (War in Iraq)	9	2.3	69.041	3.3
Aug. 2005-May 2006 (Hurricanes Katrina and Rita)	9	1.4	73.572	1.9

Source: (Taylor and van Doren, 2005).

Table A.19

Sources and Uses of Cash for FRS Companies, 2003-2004 (Current Billion Dollars)

Sources and Uses of Cash	2003	2004	Percent Change
Main Sources of Cash			
Cash Flow from Operations	105.1	135.8	29.2
Proceeds from Long-Term Debt	26.4	18.5	-29.7
Proceeds from Disposals of Assets	16.1	19.7	22.2
Proceeds from Equity Security Offerings	8.4	8.1	-3.2
Main Uses of Cash			
Additions to Investment in Place	80.0	86.5	8.2
Reductions in Long-Term Debt	26.2	18.4	-29.8
Dividends to Shareholders	42.8	36.5	-14.6
Purchase of Treasury Stock	6.1	14.0	131.2
Other Investment and Financing Activities, Net	7.9	-5.5	-169.5
Net Change in Cash and Cash Equivalents	8.8	21.2	140.7

Source: (EIA, 2004).

Table A.20

Exploration and Development Expenditures by Region for FRS Companies, 1998-2004 (Current Million Dollars)

Total E&P Expenditures	1998	1999	2000	2001	2002	2003	2004
U.S. Onshore	13,460	6,570	27,089	24,244	22,330	14,743	21,860
U.S. Offshroe	10,968	6,917	20,955	9,614	9,482	12,453	10,530
Total United States	24,428	13,487	48,044	33,858	31,812	27,196	32,390
Canada	4,806	2,056	4,881	15,324	6,687	4,903	5,318
OECD Europe	8,586	4,137	7,520	5,373	9,794	5,730	4,408
Former Soviet Union and E. Europe	1,267	606	893	881	1,273	2,120	2,042
Africa	3,134	3,094	2,719	5,547	6,091	9,187	6,901
Middle East	942	393	550	739	774	976	1,271
Other Eastern Hemisphere	3,949	3,442	6,787	4,991	6,195	4,161	3,761
Other Western Hemisphere	3,709	3,790	5,448	3,090	1,558	1,131	1,635
Total Foreign	26,393	17,518	28,798	35,944	31,372	28,208	25,336
World Total	50,821	31,005	76,842	69,802	63,184	55,404	57,726

Source: (EIA, 2004).

Table A.21

Representative Global Upstream Oil and Gas Investment Comparison

Year	O&GJ[a]	Arthur Anderson	Lehman[b]	Chase/Salomon[c]
1995	55.9	54.5	84	69
1996	63.0	48.9	97	88
1997	75.0	89.6	115	67
1998	74.2	89.0	114	82
1999	78.4	95.7	90	92
2000	85.4	124.1	108	115
2001	106.9		127	110
2002			117	121

Note: a) (Beck, 2004).
b) (IEA, 2003).
c) (Lynch, 2003).

Table A.22

U.S. Capital Spending, 1994-2003 (Current Million Dollars)

	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003
Drilling-Exploration	12,036	12,842	17,098	22,725	22,835	18,312	24,340	39,927	31,942	34,500
Production	2,365	2,519	3,354	4,458	4.349	3,479	4,625	7,586	6.070	6,556
OCS Lease Bonus	331	414	878	1,411	1,320	249	442	1,004	504	476
Subtotal	**14,732**	**15,775**	**21,330**	**28,594**	**28,504**	**22,040**	**29,407**	**48,517**	**38,516**	**41,532**
Refining	5,082	4,903	3,932	3,102	3,486	3,525	4,142	3,930	4,952	6,000
Petrochemicals	2,245	3,347	3,341	2,763	2,871	2,007	870	917	963	915
Marketing	2,473	2,545	2,913	2,960	3,024	2,613	2,867	3,300	2,310	2,310
Crude & Products Pipelines	778	768	632	851	1,228	1,058	201	570	260	260
Natural Gas Pipelines	1,352	1,527	1,120	1,704	1,928	1,824	3,261	3,008	4,850	4,850
Other Transportation	730	602	657	722	750	681	682	706	568	568
Mining & Other Energy	714	758	665	884	902	601	556	550	660	660
Miscellaneous	2,223	2,256	2,310	2,545	2,564	2,196	2,241	3,900	3,800	3,800
Subtotal	**15,597**	**16,706**	**15,570**	**15,531**	**16,753**	**14,505**	**14,820**	**16,881**	**19.363**	**19,363**
Total	**30,329**	**32,481**	**36,900**	**44,125**	**45,257**	**36,545**	**44,227**	**65,398**	**55,476**	**60,895**

Source: (Beck, 2004).

Table A.23

Worldwide Petroleum Industry Capital Spending, 1990-2001 (Current Million Dollars)

Regions and Sectors	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001
US and Canada												
Crude Oil & Natural Gas	22,048	23,424	17,003	21,504	23,940	24,616	30,140	36,674	39,075	41,890	47,538	62,205
Refineries	4,930	6,831	6,933	6,031	5,678	5,472	4,382	3,411	3,834	4,163	4,762	4,355
Subtotal	**26,978**	**30,355**	**23,936**	**27,535**	**29,618**	**30,088**	**34,522**	**40,085**	**42,909**	**46,053**	**52,300**	**66,560**
Mexico, C. and S. America												
Crude Oil & Natural Gas	6,220	7,605	6,254	5,637	7,362	9,130	9,290	10,938	9,573	10,043	10,513	12,377
Refineries	1,864	1,848	1,872	1,938	1,955	2,057	2,080	2,130	2,106	2,358	2,609	2,946
Subtotal	**8,084**	**9,453**	**8,126**	**7,575**	**9,317**	**11,187**	**11,370**	**13,068**	**11,679**	**12,401**	**13,122**	**15,323**
Western Europe												
Crude Oil & Natural Gas	14,770	16,829	12,276	11,361	12,290	13,667	14,850	16,220	14,380	14,788	15,196	17,811
Refineries	3,050	3,083	3,061	3,110	3,119	3,186	3,252	3,297	3,320	3,600	3,880	4,273
Subtotal	**17,820**	**19,912**	**15,337**	**14,471**	**15,409**	**16,853**	**18,102**	**19,517**	**17,700**	**18,388**	**19,076**	**22,084**
Middle East and Africa												
Crude Oil & Natural Gas	3,957	4,002	4,017	4,403	4,191	4,570	4,876	6,588	6,683	7,078	7,472	8,942
Refineries	1,340	1,277	1,311	1,372	1,432	1,519	1,571	1,610	1,637	1,809	1,980	2,214
Subtotal	**5,297**	**5,229**	**5,328**	**5,775**	**5,623**	**6,089**	**6,447**	**7,198**	**8,320**	**8,887**	**9,452**	**11,156**
Far East and Australasia												
Crude Oil & Natural Gas	4,436	4,695	3,922	4,194	4,156	3,893	3,799	4,605	4,459	4,580	4,701	5,555
Refineries	2,498	2,611	2,759	2,936	3,052	3,385	3,642	3,735	3,781	4,174	4,567	5,104
Subtotal	**6,934**	**7,306**	**6,681**	**7,130**	**7,208**	**7,278**	**7,441**	**8,340**	**8,240**	**8,754**	**9,268**	**10,659**
World Totals												
Crude Oil & Natural Gas	51,431	56,555	43,472	47,099	51,939	55,876	62,955	75,025	74,170	78,379	85,420	106,890
Refineries	13,682	15,600	15,936	15,387	15,236	15,619	14,927	14,183	14,678	16,104	17,798	18,892
Total World	**65,113**	**72,155**	**59,408**	**62,486**	**67,175**	**71,495**	**77,882**	**89,208**	**88,848**	**94,483**	**103,218**	**125,782**

Source: (Beck, 2004).

Table A.24

Lifting Costs by Region for FRS Companies, 2003-2004
(2004 Dollars Per Barrel of Oil Equivalent)

Region	Direct Lifting Costs 2003	Direct Lifting Costs 2004	Production Taxes 2003	Production Taxes 2004	Total 2003	Total 2004
United States						
Onshore	--	--	--	--	5.66	6.08
Offshore	--	--	--	--	3.34	4.25
Total United States	3.77	4.19	1.13	1.32	4.90	5.52
Foreign						
Canada	5.34	5.15	0.23	0.23	5.56	5.38
OECD Europe	4.39	4.54	0.84	0.70	5.23	5.24
FSU/E. Europe	4.43	5.74	0.75	1.24	5.18	6.98
Africa	3.89	4.06	1.32	1.51	5.20	5.57
Middle East	3.99	4.36	0.15	0.19	4.14	4.56
Other E. Hemisphere	2.97	4.26	1.09	1.53	4.06	5.79
Other W. Hemisphere	2.14	1.88	1.45	1.72	3.59	3.60
Total Foreign	3.96	4.25	0.88	1.01	4.84	5.27
Worldwide Total	3.87	4.23	1.00	1.16	4.87	5.39

Source: (EIA, 2004).

Table A.25

Finding Costs by Region for FRS Companies, 2001-2003 and 2002-2004
(2004 Dollars Per Barrel of Oil Equivalent)

Region	2001-2003	2002-2004	Change (%)
United States			
Onshore	9.16	7.18	-21.6
Offshore	10.24	27.66	170.0
Total United States	9.56	10.33	8.1
Foreign			
Canada	12.26	26.09	112.8
OECD Europe	9.86	12.16	23.3
Former Soviet Union and Eastern Europe	2.63	4.30	63.8
Africa	5.79	7.55	30.4
Middle East	4.05	6.76	67.1
Other Eastern Hemisphere	4.05	6.18	52.5
Other Western Hemisphere	3.98	4.98	25.0
Total Foreign	5.87	8.30	41.3
Worldwide Total	7.28	9.18	26.2

Source: (EIA, 2004).

Table A.26

The Prospectivity of a Region Is Influenced by Many Factors

Categorization	Potential Factors
Geologic	Proved Reserves
	Production
	Reserves Addition
	Undiscovered Resources
Technical	F&D Cost
	Number of IOCs
	Years of Production
	Past Peak Production
	Maturity Status
	Frontier Acreage
	Infrastructure Availability
Country	GDP
	GDP per Capita
	Oil Revenue Volatility
	Import/Export Status
	Economic System
	FDI
	Macroeconomic Stability
	Negotiation Experience
	Company Type
	Regional Influences
	Corruption Index
Geopolitical	Political Risk
	OPEC Membership
	Political Agenda
	Political Systems
Legal	Rule of Law

Table A.27

Hydrocarbon Net Exporting Countries Oil and Natural Gas Exports and Fiscal Revenues in 2003

Country	Oil and Gas Exports as a percent of world oil and gas exports	Oil and Gas Exports as a percent of country's GDP	Country's fiscal oil and gas as share of country's GDP
Saudi Arabia	13.5	38.3	28.1
Russian Federation	11.8	17.0	6.0
Norway	6.5	18.4	12.2
United Arab Emirates	4.7	36.8	35.8
Iran	4.3	19.8	16.3
Nigeria	4.3	46.1	28.0
Algeria	3.9	36.2	26.4
United Kingdom	3.8	1.3	0.4
Netherlands	3.4	4.0	n/a
Venezuela	3.3	24.6	23.0
Kuwait	3.0	44.8	48.1
Mexico	3.0	3.0	7.9
Indonesia	2.4	6.3	4.5
Canada	2.4	1.7	0.2
Libya	1.9	47.6	40.5
Iraq	1.6	38.4	n/a
Qatar	1.5	47.0	24.9
Oman	1.5	43.1	35.4
Angola	1.4	65.3	28.3
Malaysia	1.2	7.4	4.3
Kazakhstan	1.1	23.6	6.2
Argentina	0.9	4.3	1.7
Bahrain	0.8	53.9	24.4
Syria	0.7	19.3	14.4
Brunei Darussalam	0.6	80.0	29.1
Denmark	0.6	1.8	0.7
Vietnam	0.6	9.8	5.3
Trinidad & Tobago	0.6	34.4	11.5
Yemen	0.5	30.5	23.6
Colombia	0.5	4.4	2.9
Egypt	0.5	3.9	0.8
Turkmenistan	0.5	26.6	9.3
Equatorial Guinea	0.5	96.6	23.7
Ecuador	0.4	9.7	13.2
Azerbaijan	0.4	31.5	15.2
Congo	0.3	59.1	20.4
Sudan	0.3	12.3	9.5
Gabon	0.2	42.6	16.2
Cameroon	0.2	7.6	4.5
Cote d'Ivoire	0.1	4.9	1.3
Bolivia	0.1	6.1	4.6
Papua New Guinea	0.1	13.0	4.6
Uzbekistan	0.1	3.8	5.2
Chad	0.1	8.3	0.5
Total: 44 Countries	**90.1**		

Source: (IMF, 2004).

Table A.28

One Factor, Two Dimensional Contract Classification

Development Status	Contract Type
Industrial	JV
Developing	JV, PSC

Note: JV=Joint Venture, PSC=Production Sharing Contract.

Table A.29

One Factor, Five Dimensional Contract Classification

Political System	Example Country
Mature Democracy	US, UK, Canada, Norway
Factional Democracy	Ecuador, Venezuela, Columbia
Paternalistic Democracy	Saudi Arabia, Kuwait, Gulf States
Predatory Democracy	Nigeria
Reformist Democracy	Indonesia

Table A.30

Multi-Dimensional Contract Classification

Country/Region	Subcategory	Example Country
Industrialized	Laissez Faire	US, UK, Spain, Canada, Australia, Sweden, Denmark, Finland, Switzerland, Argentine, Chile
	Dirigiste	France, Germany, Norway, Japan, Italy, Austria, Portugal, Greece
OPEC	Rich	Saudi Arabia, Kuwait, UAE, Libya, Qatar, Oman, Iran, Iraq
	Less Rich	Algeria, Venezuela, Indonesia, Nigeria
FSU	High Prospectivity	Russia, Kazakhstan, Uzebekistan, Turkmenistan
	Modest Prospectivity	Azerbaijan, Tajikistan, Kyrgistan
	Low Prospectivity	Ukraine, Belarus
SouthEast Asia	High Prospectivity	Malaysia
	Modest Prospectivity	Thailand, China
	Low Prospectivity	Korea, Taiwan
Africa	High Prospectivity	Angola, Egypt, Libya, Nigeria
	Modest Prospectivity	Chad, Sudan, Niger
	Low Prospectivity	Gabon, Senegal, Morocco

Table A.31

Two Factor, Four Dimensional Contract Classification

Economic Strength	Importer	Exporter
Weak	PSC	JV
	RC	PSC
Strong	JV	PSC
	PSC	SC

Note: JV = Joint Venture, PSC = Production Sharing Contract, RC = Risk Contract, SC = Service Contract.

Table A.32

Representative Contract Terms and Government Take

Country	Contract Type[a]	Government Take[b]	Star System[c]
USA	R/T	Deepwater: (38, 42)	Deepwater: 4
		Shelf : (48,51)	Shelf: 3
Mexico	SC	(30, 32)	
North America			
Argentina	R/T	(47, 49)	5
Colombia	R/T	(79, 82)	1
Ecuador	PSA	(58, 60)	3
Peru	PSA, R/T	(58, 62)	5
Trinidad & Tobago	PSA	Offshore: (48, 50)	Offshore: 4
		Onshore: (62,66)	Onshore: 3
Venezuela	SC	(88, 93)	1
South & Central America			
Italy			5
Norway			2
United Kingdom			5
Europe			
Kazakhstan	PSA, ROR	(83, 88)	
Russian Federation			1
Former Soviet Union			
Syria	PSA	(83, 87)	1
Yemen	PSA	(72, 79)	2
Middle East			
Angola	PSA	(81, 88)	
Republic of Congo	R/T	(67, 69)	
Egypt	PSA	(79, 82)	Offshore: 3
		(85, 90)	Onshore: 1
Gabon	PSA	(69, 76)	1
Nigeria			1
Tunisia	PSA, R/T	(79, 85)	
Africa			
Australia	R/T	Off: (53, 56)	Offshore: 4
		On: (63, 66)	Onshore: 3
Brunei	R/T	(82, 84)	2
China	PSA	(72, 77)	3
India	PSA	(61, 69)	
Indonesia	PSA	East: (69, 71)	1
		West: (87, 89)	1
Malaysia	PSA	Frontier: (69, 74)	Frontier: 3
		Onshore: (88, 91)	Onshore: 2
Papua New Guinea	R/T, ROR	(67, 76)	2
Thailand	R/T	(69, 74)	2
Vietnam	PSA	(79, 82)	
Asia Pacific			

Footnote: (a) PSA = Production Sharing Agreement, R/T = Royalty Tax, ROR = Rate of Return Features, SC = Service Contract.
(b) Source: (Johnston, 1994).
(c) Source: (Van Meurs and Seck, 1995 and 1997).

Table A.33

The Notion of Take Changes Throughout the Life of a Prospect

Stage	Notation	Characteristics
Bid Submission	τ_1	Based on estimates of the field size distribution, expected development cost, production schedule, fiscal terms F, and work commitment W, take is evaluated
Bid Acceptance and Award	τ_2	F and W are negotiated with HG to determine values of τ_2
Commercial Discovery	τ_3	Field size is known and with estimates of development and production costs, F will determine τ_3 subject to exogenous conditions
Production	τ_4	Field size, development costs, production expenses, etc. are known with a higher degree of certainty, and as production proceeds, these parameters become better defined. Take will vary throughout the productive life of a field based on the terms of F and exogenous conditions
Abandonment	τ_5	At abandonment and with perfect information, a "look-back" analysis can be performed to determine the exact value of take as long as cost and revenues are known precisely and the terms of F are available

Table A.34

Trends in PSA Contract Terms

	Maximum Royalty (%)	Maximum Cost Oil (%)	IOC Profit Oil		Bonus	
			Max (%)	Min (%)	Signature ($M)	Production ($M)
Onshore	9+	70+++	53+	30	4	5 - -
Offshore	7+++	68+	61++	33++	1.3 -	6
Exporters	10+++	69++	50++	27+	4.5+	8
Importers	5	69++	60+	38+	1.8+	4.6 - -
OPEC	5++	100+++	55++	30+	1.1 - -	10+
South/Central Africa	8+	70+++	62+	32+	2.5	5 -
Eastern Europe	6+++	62+++	58+	38 -	0.8+++	2++
Asia/Australia	5.5++	76+	55++	28	1.8 -	5 - -
Central America/Caribbean	10+	100+++	90+++	50+++	n/a	n/a
Middle East	8.5+	40 -	25 - -	16	6+++	8
North Africa	10+++	85+++	72+++	27++	3+++	6+++
South America	8.5+	60+++	45 -	30 - -	n/a	10+

Source: (Bindemann, 1999).

Footnote: (1) Figures represent 1997/1998 contract averages.

(2) + (-) slight increase (decrease); ++ (- -) increase (decrease); +++ (- - -) strong increase (decrease).

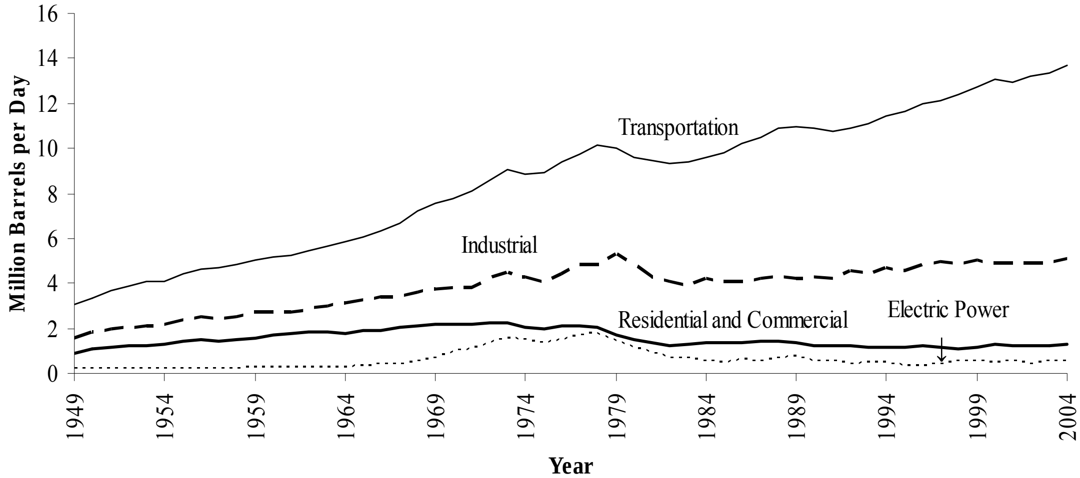


Figure A.1. Estimated Petroleum Consumption by Sector, 1949-2004 (EIA, 2005).

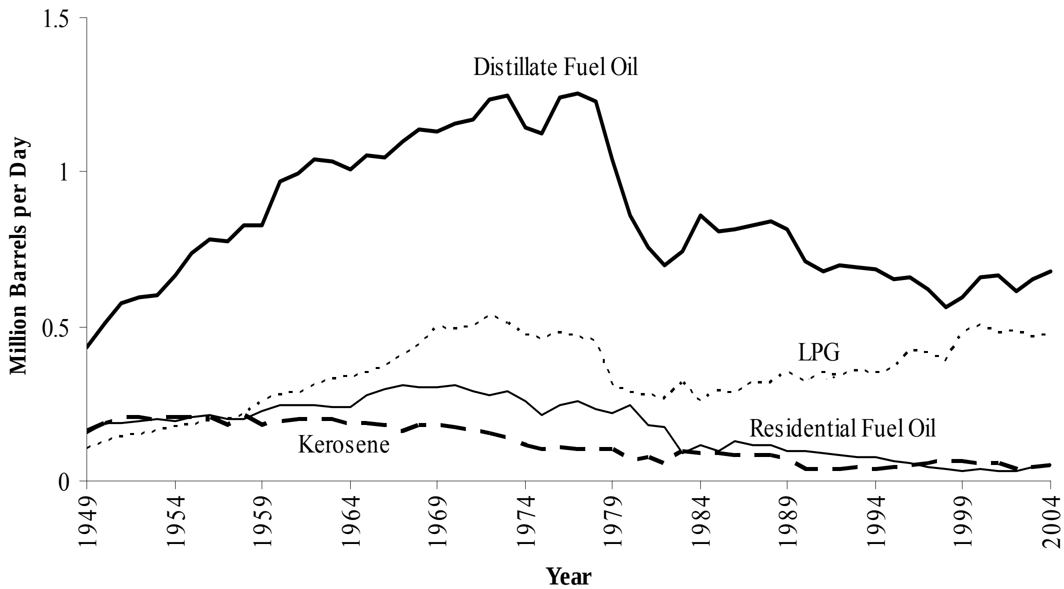


Figure A.2. Estimated Petroleum Consumption – Residential and Commercial Sectors, 1949-2004 (EIA, 2005).

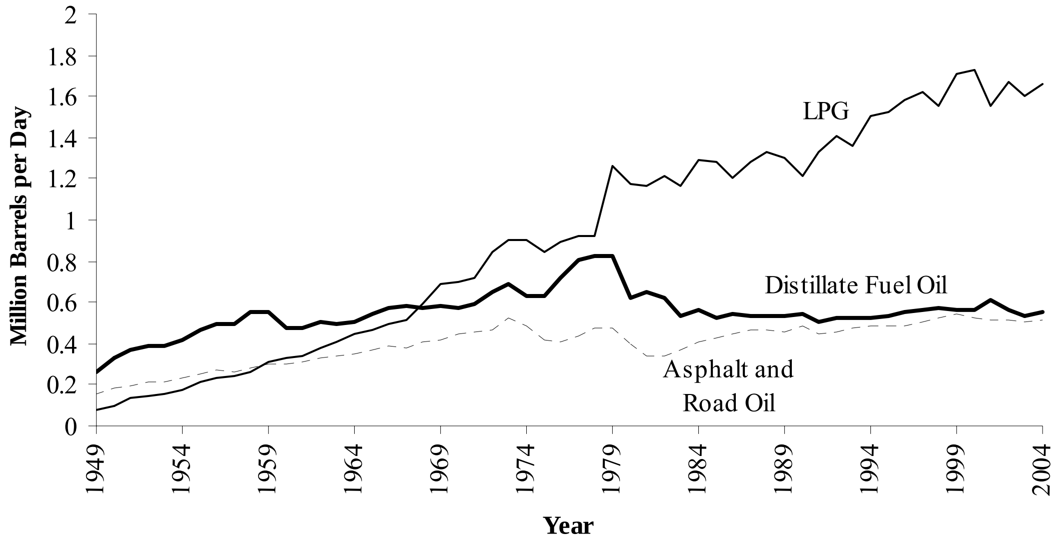


Figure A.3. Estimated Petroleum Product Consumption – Industrial Sector, 1949-2004 (EIA, 2005).

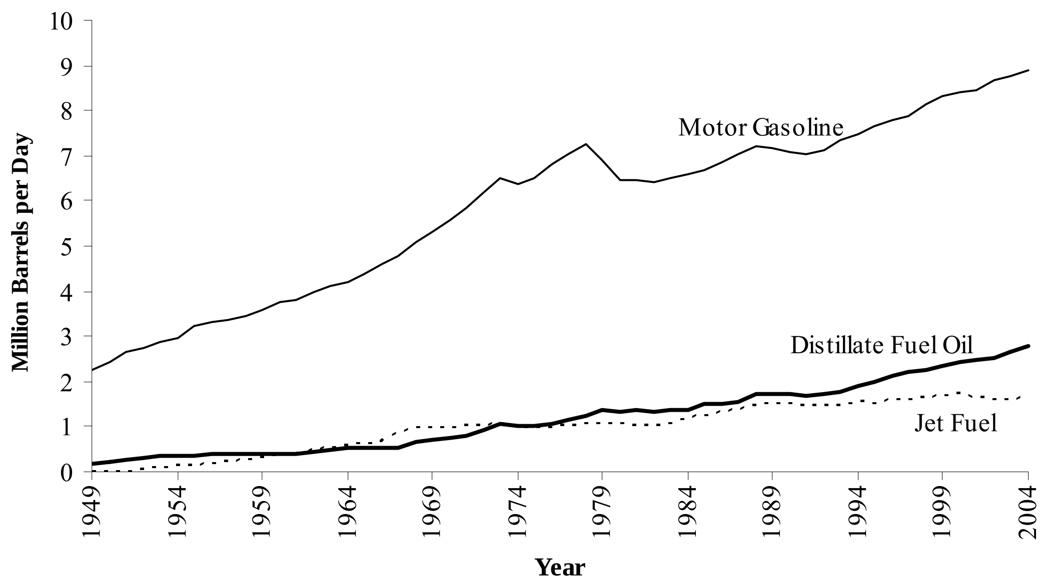


Figure A.4. Estimated Petroleum Product Consumption – Transportation Sector, 1949-2004 (EIA, 2005).

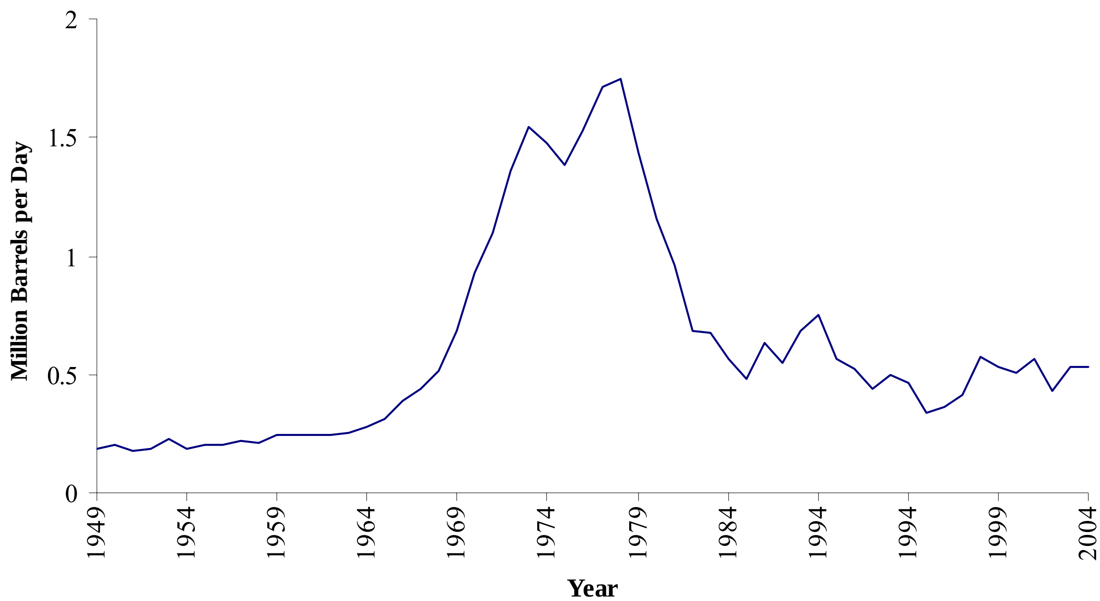


Figure A.5. Estimated Petroleum Consumption – Electric Power Sector, 1949-2004 (EIA, 2005).

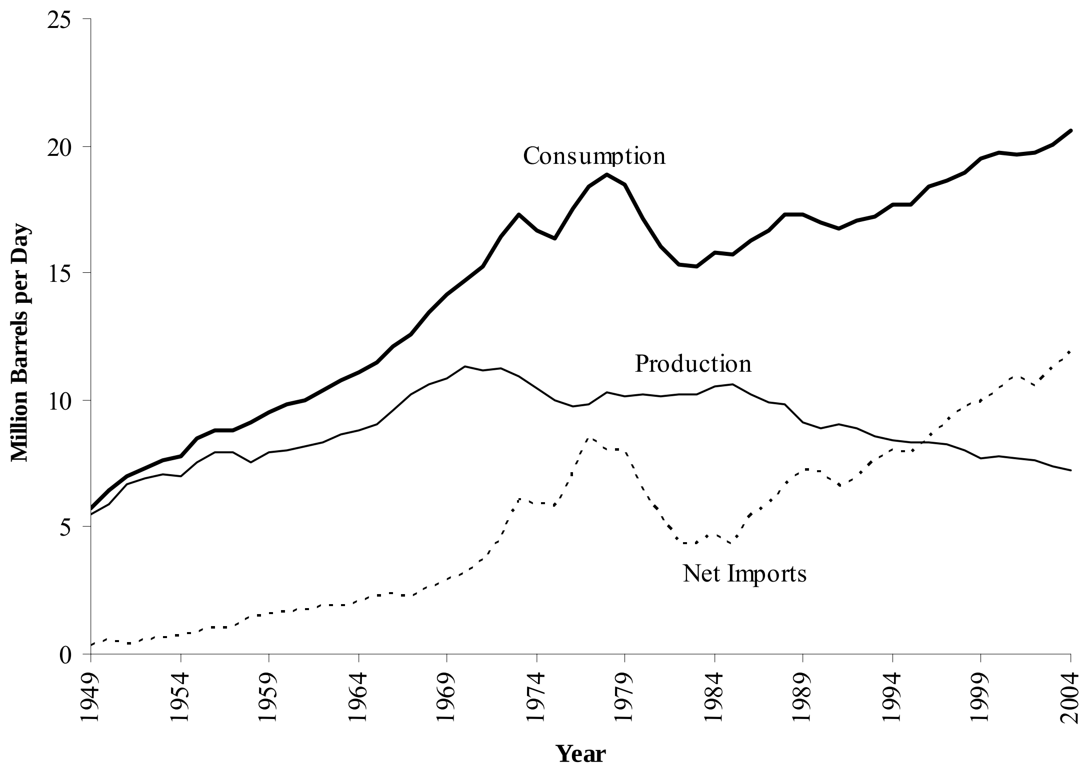


Figure A.6. Production, Consumption, and Net Imports of Crude Oil, 1949-2004 (EIA, 2005).

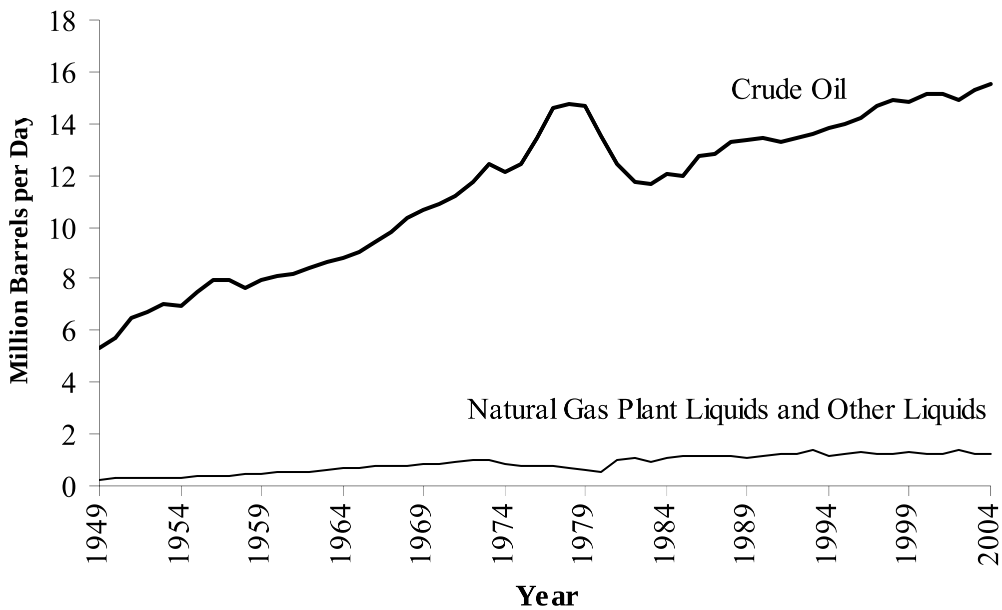


Figure A.7. Refinery Input, 1949-2004 (EIA, 2005).

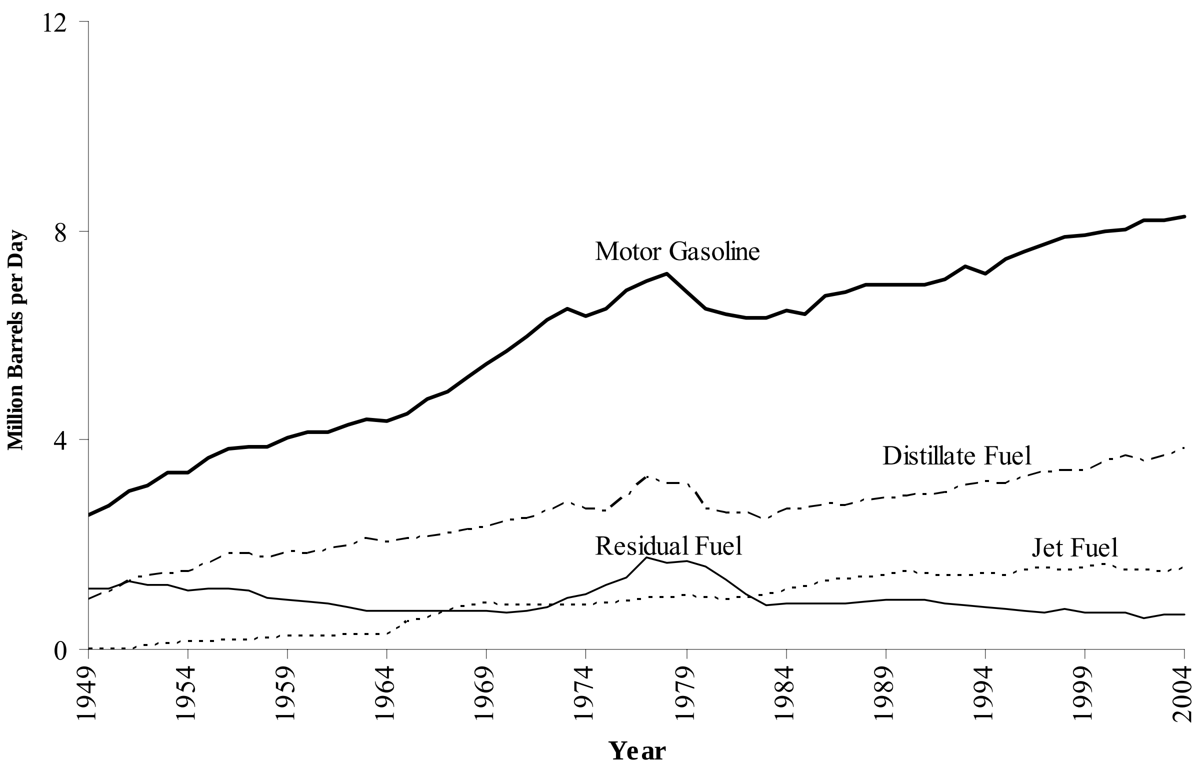
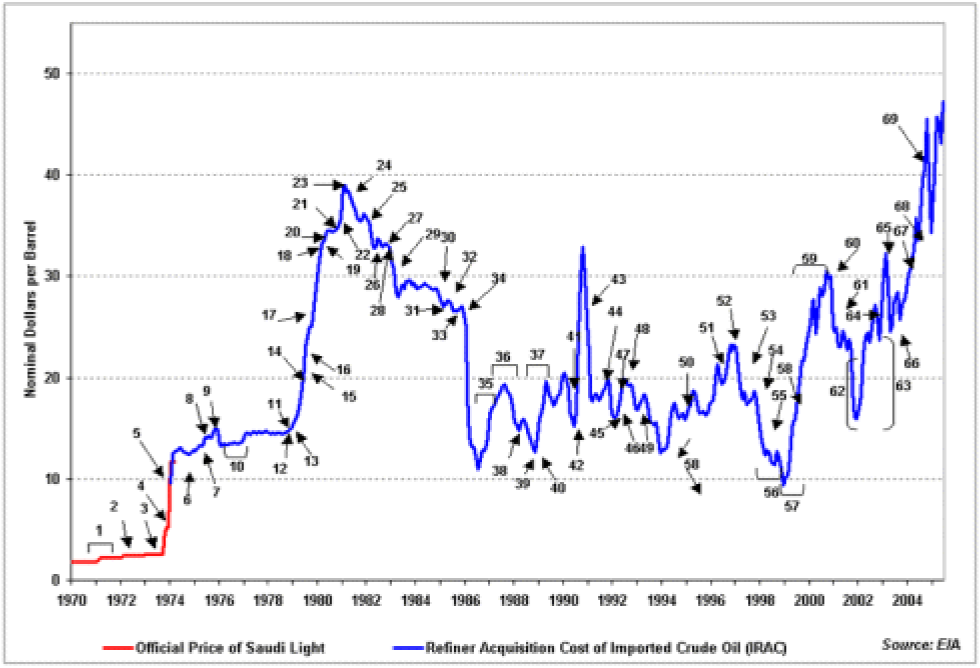


Figure A.8. Refinery Output, 1949-2004 (EIA, 2005).



Selected Events:

1 – OPEC begins to assert power, raises tax rate and posted prices
5 – OPEC freezes posted prices
16 – OPEC raises prices 15%
23 – First major fighting in Iran-Iraq war
42 – Iraq invades Kuwait
50 – Nigerian oil workers strike
51 – Extreme cold weather in the US and Europe
58 – OPEC pledges additional production cuts for the thirds time
62 – September 11, 2001 terrorist attacks
65 – Continued unrest in Venezuela
69 – Hurricane Ivan hits the Gulf of Mexico

Figure A.9. World Nominal Oil Price Chronology (EIA, 2005).

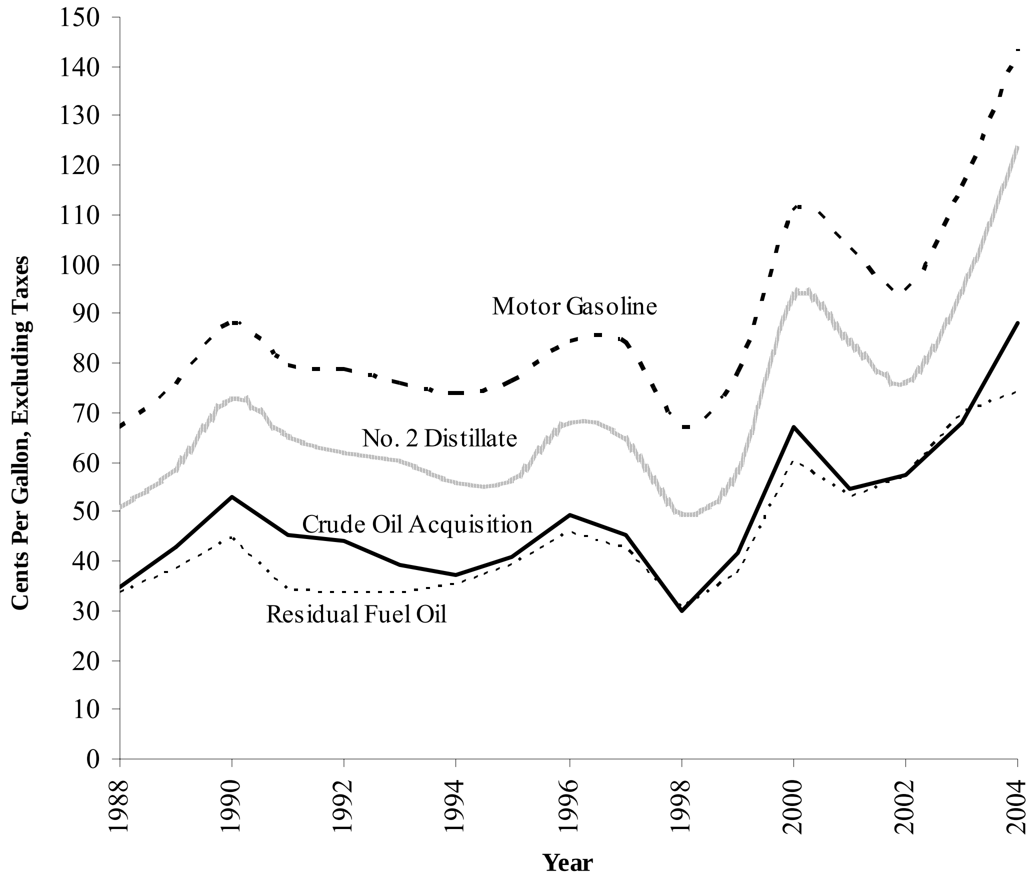


Figure A.10. Crude Oil Refiner Acquisition Costs and Refiner Sales Prices for Selected Petroleum Products, 1988-2004 (EIA, 2005).

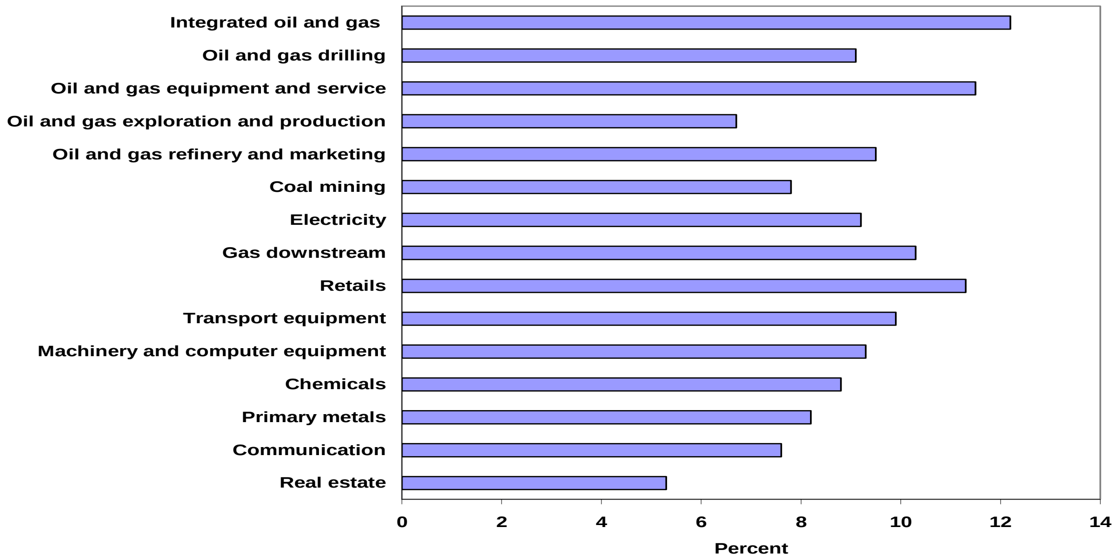


Figure A.11. Average Return on Investment by Industry, 1993-2002 (IEA, 2003).

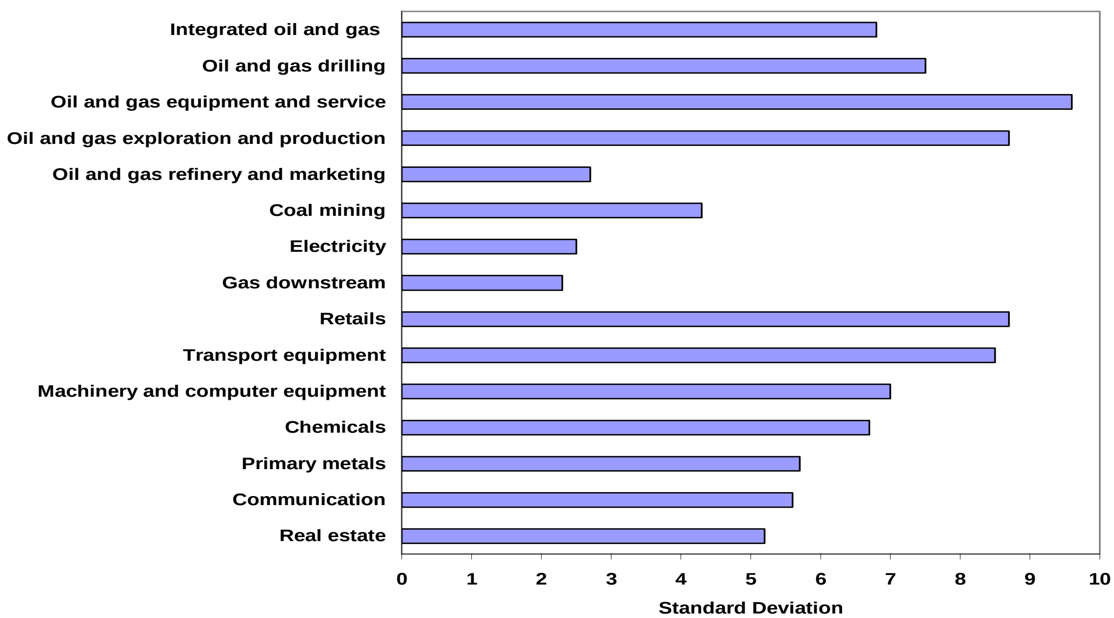


Figure A.12. Volatility of Return on Investment by Industry, 1993-2002 (IEA, 2003).

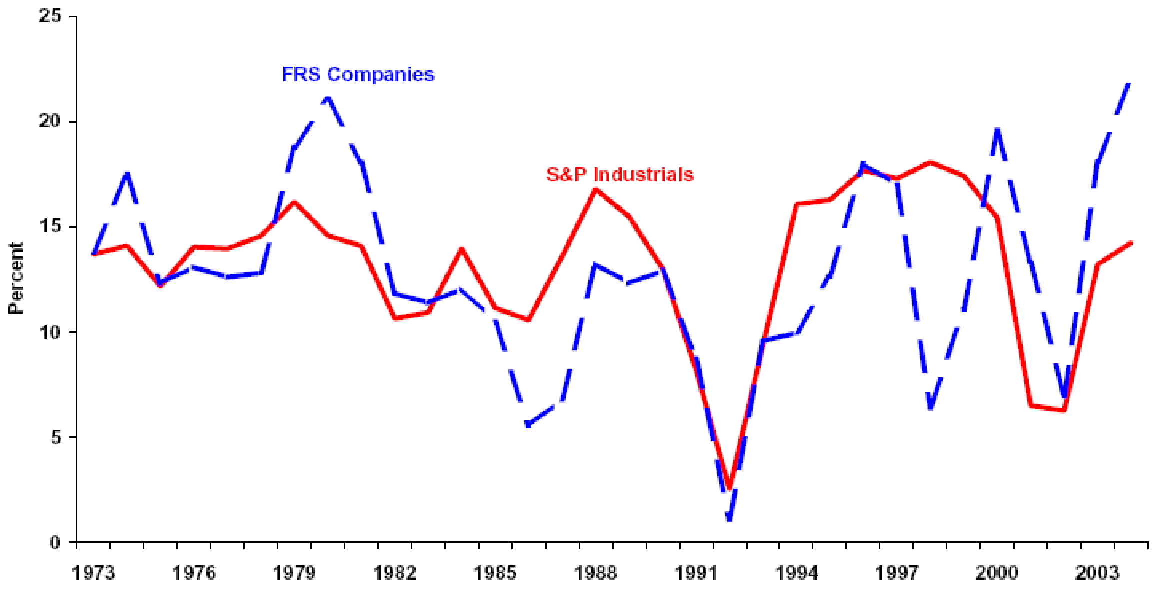


Figure A.13. Return on Stockholder's Equity for FRS Companies and the S&P Industrials, 1973-2004 (EIA, 2004).

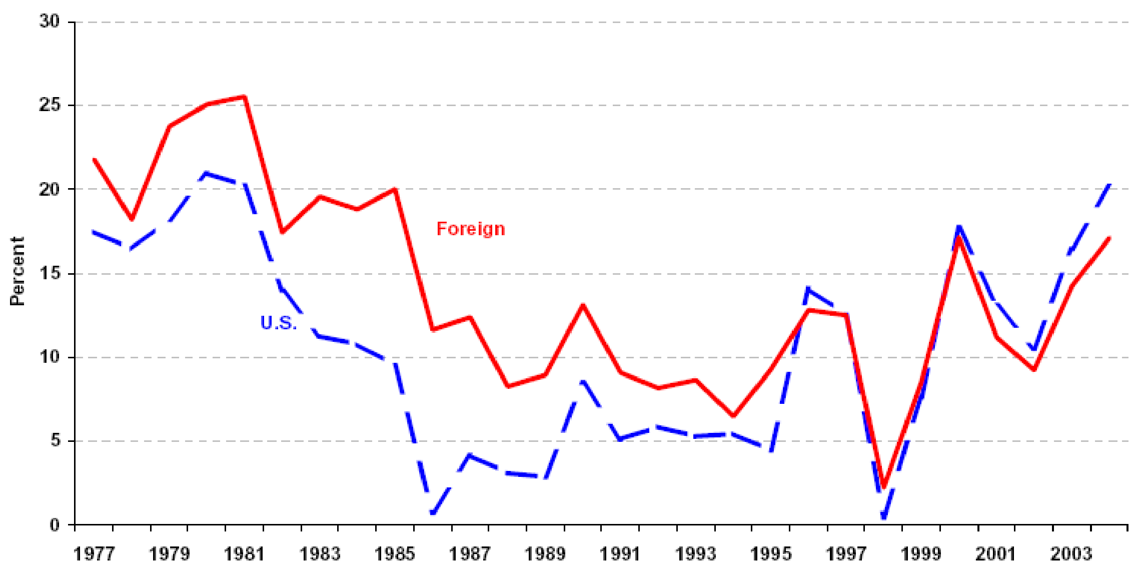


Figure A.14. Return on Net Investment for U.S. and Foreign Oil and Gas Production, 1977-2004 (EIA, 2004).

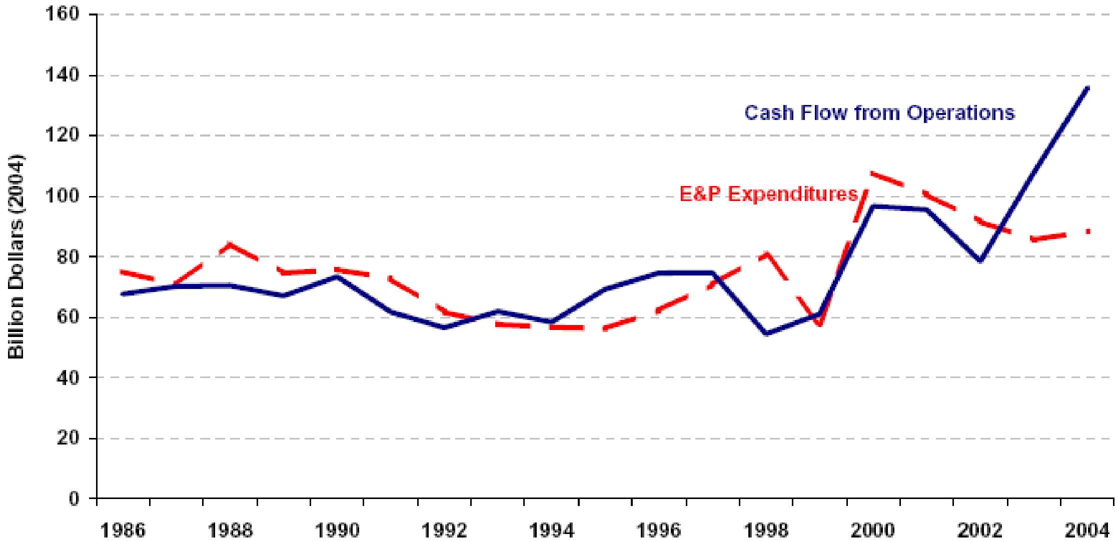


Figure A.15. Cash Flow from Operations and Exploration and Production Expenditures for FRS Companies (EIA, 2004).

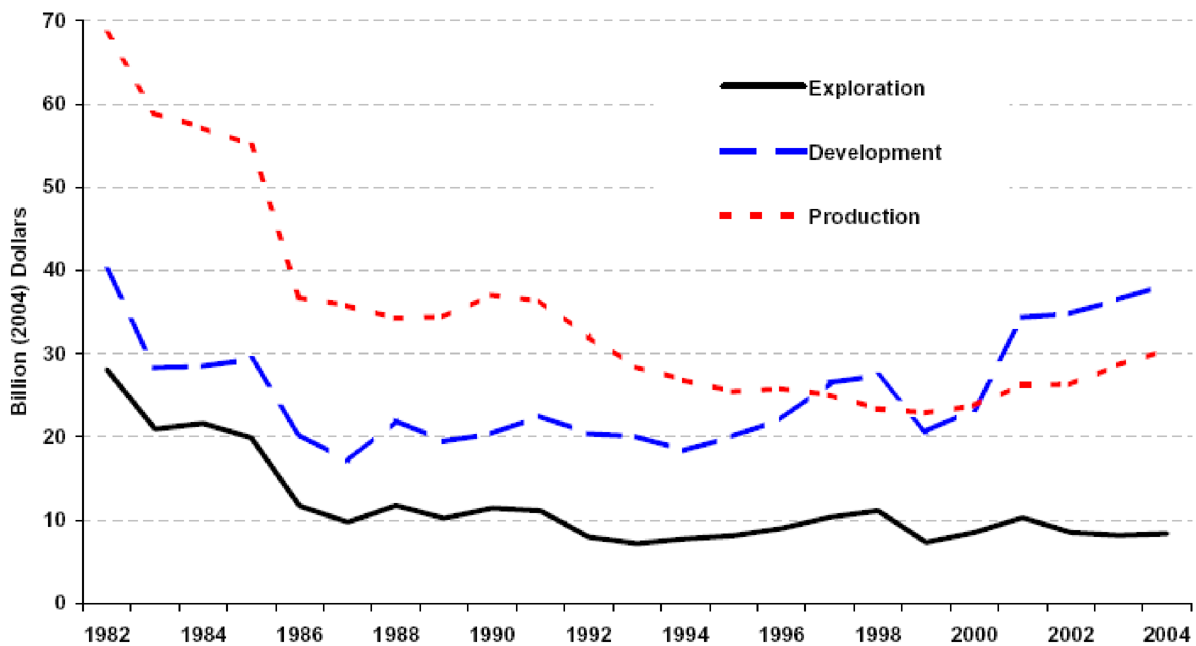


Figure A.16. Worldwide Expenditures for Exploration, Development, and Production for FRS Companies (EIA, 2004).

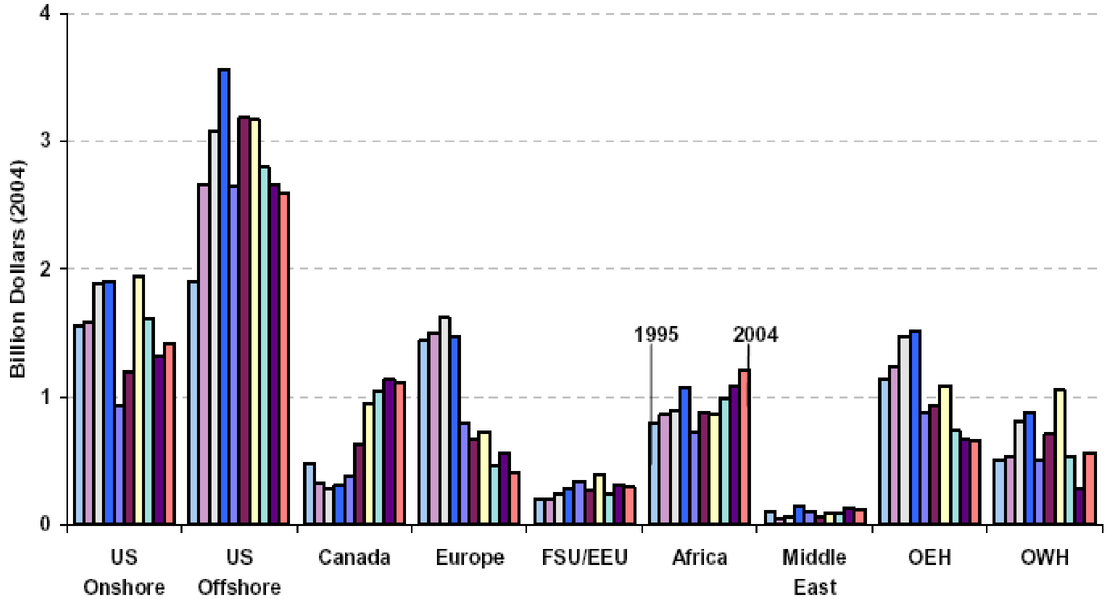


Figure A.17. FRS Expenditures for Oil and Natural Gas Exploration by Region, 1995-2004 (EIA, 2004).

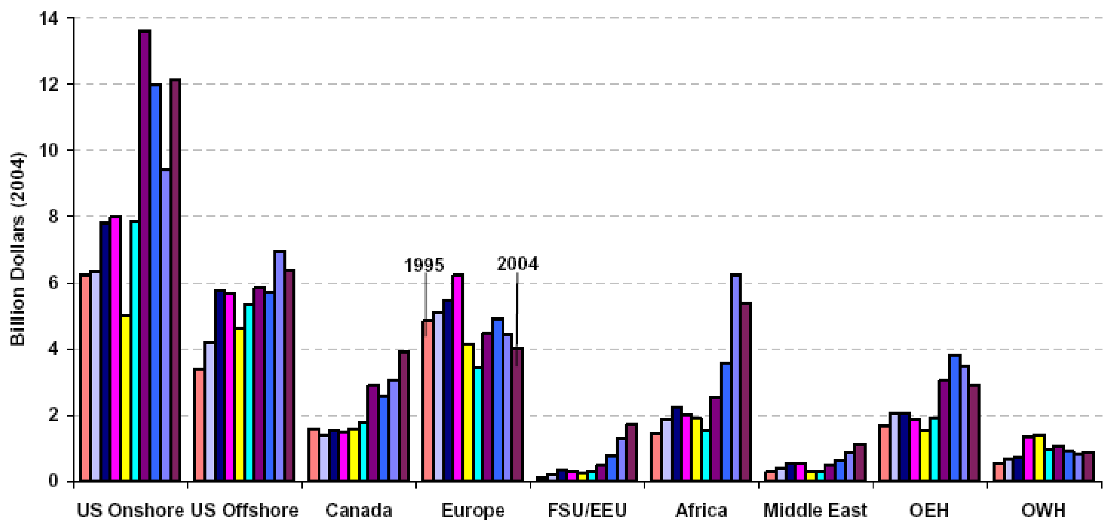


Figure A.18. FRS Expenditures for Oil and Natural Gas Development by Region, 1995-2004 (EIA, 2004).

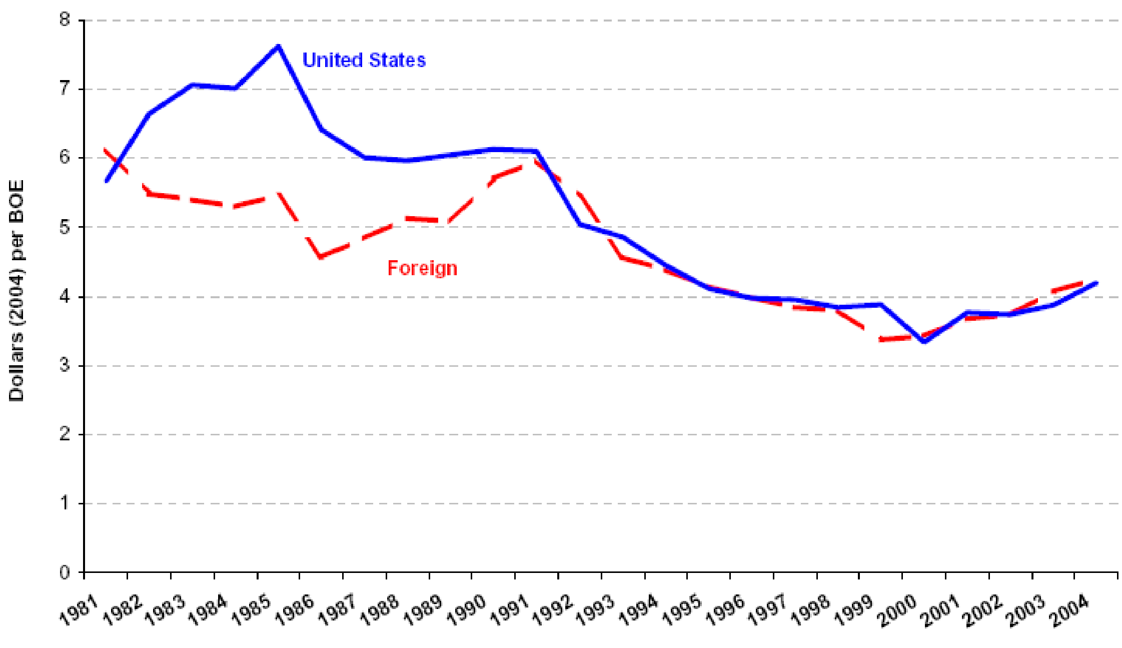


Figure A.19. Direct Oil and Gas Lifting Costs for FRS Companies, 1981-2004 (EIA, 2004).

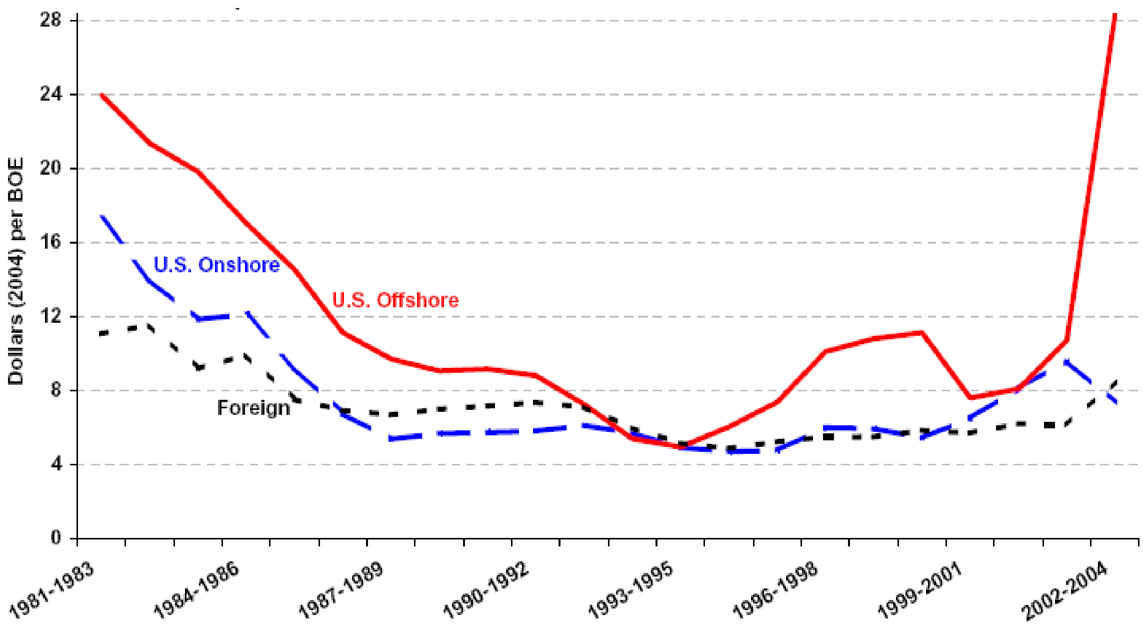


Figure A.20. U.S. Onshore, U.S. Offshore, and Foreign Three-Year Weighted-Average Finding Costs for FRS Companies, 1981-1983 to 2002-2004 (EIA, 2004).

The Department of the Interior Mission

As the Nation's principal conservation agency, the Department of the Interior has responsibility for most of our nationally owned public lands and natural resources. This includes fostering sound use of our land and water resources; protecting our fish, wildlife, and biological diversity; preserving the environmental and cultural values of our national parks and historical places; and providing for the enjoyment of life through outdoor recreation. The Department assesses our energy and mineral resources and works to ensure that their development is in the best interests of all our people by encouraging stewardship and citizen participation in their care. The Department also has a major responsibility for American Indian reservation communities and for people who live in island territories under U.S. administration.

The Minerals Management Service Mission

As a bureau of the Department of the Interior, the Minerals Management Service's (MMS) primary responsibilities are to manage the mineral resources located on the Nation's Outer Continental Shelf (OCS), collect revenue from the Federal OCS and onshore Federal and Indian lands, and distribute those revenues.

Moreover, in working to meet its responsibilities, the **Offshore Minerals Management Program** administers the OCS competitive leasing program and oversees the safe and environmentally sound exploration and production of our Nation's offshore natural gas, oil and other mineral resources. The MMS **Minerals Revenue Management** meets its responsibilities by ensuring the efficient, timely and accurate collection and disbursement of revenue from mineral leasing and production due to Indian tribes and allottees, States and the U.S. Treasury.

The MMS strives to fulfill its responsibilities through the general guiding principles of: (1) being responsive to the public's concerns and interests by maintaining a dialogue with all potentially affected parties and (2) carrying out its programs with an emphasis on working to enhance the quality of life for all Americans by lending MMS assistance and expertise to economic development and environmental protection.