CHAPTER 1
INTERNATIONAL ENERGY MARKETS

Crude Oil
The world crude oil demand and supply have always presented an interesting imbalance, especially after the middle of the 20th century. Industrialized countries have usually lacked necessary resources to supply their own oil needs, and countries with abundant resources and production capacity have not needed all they could produce for their own economies. This imbalance created a mutually beneficial situation where industrialized countries imported oil from resource-rich countries which, in turn, developed their economies with revenues from oil exports. Although oil supply shocks of the 1970s pushed industrialized countries to substitute alternative fuels for oil, and increase conservation and efficiency efforts, oil remained a major fuel for these economies. Efforts of building oil stocks as an insurance against possible future shocks as well as the slow nature of implementing the policies mentioned above kept demand for oil strong and created the financial environment for development of resources outside the Organization of Petroleum Exporting Countries (OPEC). Lower prices of the 1980s and increasing demand from growing economies worldwide enhanced the market for oil. Nevertheless, as the following chart demonstrates, the Middle East, with 686 billion barrels of proved reserves, accounts for 65% of world’s total crude oil reserves. A part of these reserves are in the hands of countries that are members of OPEC.

The table next page presents the data on oil production and consumption in different regions for the years 1970, 1980, 1990, and 2000. Clearly, the imbalance between producing and consuming regions are getting larger. For example, North American production is staying fairly constant while its consumption continues to rise, making the region increasingly more dependent on imports. In 1970, the region needed less than three million b/d of imports while, in 2000, more than eight million b/d, or more than one third of total consumption in the region was imported. Asia Pacific is another region with increasing dependence on imports despite increases in its production. Between 1970 and 2000, import needs of the region increased from about five to 13 million b/d despite the dampening effect of the Asian economic crisis on oil demand. Note that the increase in consumption within the Asia Pacific region is mostly responsible for the increase in the emerging market economies (EMEs) as evidenced at the bottom of the table below. Overall, the share of EMEs in total consumption increased from 13% in 1970 to 32% in 2000 while the share of OECD countries fell from 74% to 62%. About half of the increase occurred in the 1990s.

On the other hand, Europe has been able to lower its import needs in the 1990s, partially due to increased production (mostly from the North Sea) and partially due to keeping demand under control. Europe imported more than 10 million b/d in 1990 as compared to nine million b/d in 2000. Note that the share of 15 members of the EU in world oil consumption decreased from 26% in 1970 to 18% in 2000. The Middle East, Africa and the FSU remain the significant exporting regions. Increasing production in the 1990s also caused South and Central American exports to double between 1990 and 2000 from about one million b/d to more than two million b/d.

In Africa, production increased only about 9% between 1970 and 1990 but since then it has risen 17%. This increase allowed African exports to also increase from about 4.7 million b/d in 1990 to 5.3 million b/d in 2000 despite an increase in consumption of about 24% between 1990 and 2000. The Middle East production has risen significantly from about 17.5 million b/d in 1990 to almost 23 million b/d in 2000, after a decline in the 1980s. As consumption in the region remains fairly low at 4.3 million b/d (albeit reflecting a 26% increase from 3.4 million b/d in 1990), the region exported roughly 4.6 million b/d more in 2000 than in 1990.

The FSU region finally reversed the declining trend in production. Although still not as high as in the 1980s, the region now produces more than eight million b/d. More importantly, with new production expected from the Caspian region producers as well as from Russia, and consumption not expected to increase as rapidly, the FSU exports are expected to increase from the current level of 4.5 million b/d to possibly 10 million b/d by 2010. The Middle East is clearly the major supplier of oil to the world with almost 19 million b/d (44% of total exports), followed by Africa with about 6 million b/d (14% of total exports), the FSU (mostly Russia at this time) with more than 4 million b/d and Latin America with more than 3 million b/d (see map and table below). North America (mostly the U.S.), Asia-Pacific (Japan in particular and increasingly China) and Europe are major importing regions.

The following table confirms the previous observation that most of the increase in oil imports occurred outside the developed world. Imports almost doubled to more than 16 million b/d between 1990 and 2000 in the rest of the world, although the U.S. imports also increased by about three million b/d (or, 38%) in the 1990s. Note that Western Europe has been able to sustain an import level of about 10 million b/d throughout the 1990s.


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Data on crude oil and product exports for 2000 are presented below. Clearly, the Middle East is the largest exporter of crude oil (16.7 million b/d) as well as products (2.2 million b/d). The share of the Middle East in total exports of crude oil is about 50%. The second largest exporter of crude oil is West Africa with 3.2 million b/d, accounting to about 10% of total world exports although Africa is not a significant exporter of products. The FSU is the third largest exporter of crude oil (2.9 million b/d) and the second largest exporter of products (1.4 million b/d).

The U.S. and Asia Pacific export significant amounts of products although their crude oil exports are relatively small. The U.S., alone, exported 826,000 barrels of products a day in 2000 (almost 9% of the world total). Countries in the Asia Pacific region exported more than one million b/d, or 11% of the world total. This is because of the large size of downstream industry in these regions. North American imports are quite diversified and come from within North America (27%), South and Central America (22%), the Middle East (21%), Africa (14%) and Western Europe (11%). Western Europe also has a fairly balanced portfolio of supplying regions with 36% coming from the Middle East, and 26% from each of Africa and the FSU. In comparison, Japan and Asia Pacific heavily depend on a single region: 79% of Japan’s and 74% of other Asian imports originate from the Middle East.

On the supply side, OPEC continues to dominate the market, producing 30 to 32 million b/d. Note that OPEC supplies are more volatile across the four quarters than OECD or other non-OPEC supplies, reflecting the swing, or marginal, producer role the organization (or at least some of its members) plays in the world crude oil market.

Most of the world’s proved natural gas reserves (about 72%) are located in two regions: the FSU and the Middle East, although there is little production relative to the size of its reserves in the latter region (see chart below). Both regions hold roughly 2,000 tcf (or about 56 tcm) of natural gas reserves as compared to world total reserves of 5,300 tcf (150 tcm).

The data on demand and supply balance in the world crude oil market for four quarters of 2001 are summarized in the table below. The fourth quarter of 2001, for example, total oil demand from Organization for Economic Cooperation and Development (OECD) members was 48.7 million b/d (about 64% of total world demand). During the same period, oil supplies from OECD were only 23.4 million b/d, which accounts for about 30% of total world supply. The U.S., by far the single largest consumer of oil, produces roughly 9 million b/d, or 44% of its demand for oil. Japan is almost totally dependent on imports to meet its demand of 5.6 million b/d. Note that the share of OECD in world demand and supply remains fairly constant throughout the year although world demand and supply fluctuate from one quarter to another. The increase in winter fuel demand experienced in the fourth and first quarters mostly in OECD countries also cause the fluctuations in the global demand.
Despite the size of their reserves, the FSU and the Middle East are not the largest producers of natural gas. North America has been the leading producer as well as consumer of gas for decades although the FSU production increased significantly from 19 bcf/d in 1970 to 69 bcf/d in 2000 while the North American production increased only from 62 bcf/d to 72 bcf/d over the same period (see table above).

Although there has been a ten-fold increase in production in the Middle East since 1970, with only 20 bcf/d, the region ranks as the fifth largest producing region after Europe that produced almost 29 bcf/d and the Asia Pacific region that produced almost 26 bcf/d in 2000. Note that the share of OECD production fell from 73% in 1970 to 44% in 2000 while the share of production from the EMEs increased from 5% to 27% over the same period.

Consumption values are very similar to production values. This is partially due to the fact that natural gas, unlike oil, is difficult and expensive to ship via tankers over long distances, especially without long-term agreements among producers and consumers (see the LNG chapter, Chapter 12, for further discussion of these issues). As a result, most gas is used or traded locally. Accordingly, consumption numbers are almost identical to production numbers for North America, South and Central America, the Middle East and Asia Pacific.

Nevertheless, there is significant trade between the FSU region and Europe as well as between Africa and Europe. The FSU exports about 15-16 bcf/d while Europe imports about 16 bcf/d. There are about six bcf/d of exports from Africa (see map below).

Electricity

In 1999, 14 trillion kWh of electricity was generated worldwide (see chart next page). While the share of North America stayed roughly the same since 1980 at about 27%, Far East & Oceania’s share increased significantly from 13% in 1980 to 23% in 1999. Western Europe, the next largest region, generated 2,785 billion kWh, or 17% of the world’s total in 1999, as compared to 1,845 billion kWh, or 19% of the world’s total in 1980. Electricity generation in Eastern Europe & FSU actually declined from 1,604 billion kWh (16%) in 1980 to 1,509 billion kWh (9%) in 1999, mostly after the break-up of the Soviet Union and consequent economic collapse in the early 1990s. Central & South America increased its generation from 308 billion kWh (3%) to 394 billion kWh (2%). The net electricity generation in the Middle East more than quadrupled from 92.41 billion kWh in 1980 to 418 billion kWh in 1999, but still accounting for only 3% of the world’s total. Similarly, doubling of the African generation from 190 billion kWh in 1980 to 394 billion kWh did not change the share of the region within the world’s total, which stands at 2%.

The fuel portfolio for 1980, 1990 and 1999 used in power generation worldwide is depicted in the chart below. The world continues to generate most of its electricity by burning fossil fuels, i.e., coal, natural gas and oil products, in conventional thermal facilities. Generation from these facilities increased from 5,589 billion kWh in 1980 to 8,798 billion kWh in 1999 although the share of these fuels in total generation declined slightly from 70% to 63% over the same period.
Hydroelectric facilities are still the second largest source of electric power in the world with 2,607 billion kWh in 1999, but their share also declined from 22% in 1980 to 19% in 1999. Nuclear generation that expanded significantly from 684 billion kWh in 1980 to 2,396 billion kWh in 1999 replaced the lost share of conventional and hydro generation and now it accounts for 17% of world's total generation as compared to only 8% in 1980. Finally, geothermal generation increased from 31 billion kWh (0%) to 227 billion kWh (1%). Other sources of power generation such as wind, solar and biomass are not large enough to register in this chart (see Chapter 16 for detailed discussion of alternative technologies). However, generation by fuel show significant variation across different regions of the world. In North America, conventional fuels account for 64%, nuclear for 18%, hydro for 15% and renewables for 2% of net generation. The role of natural gas has been increasing within the conventional thermal fuels. Similar to the world trend, nuclear generation expanded its share from 11% in 1980 at the expense of conventional and hydro generation, which used to account for 69% and 20% of total generation in 1980.

Between 1980 and 1999, Western Europe also went through a similar shift from conventional and hydro sources of generation towards nuclear power, whose share increased from 12% to 15%. Over the same period, the share of conventional thermal in total generation declined to 48% from 64% and the share of hydro fell to 19% from 23%. Renewables account for the remaining 21% of generation in 1999. With increased emphasis on global warming and commitment to Kyoto protocol, Western Europe likely will increase the use of renewables such as wind in the near future. Already, Germany and Denmark are investing large sums in wind farms.

In Far East and Oceania, 72% of generation was from conventional thermal facilities in 1999 (same as in 1980). Nuclear power increased its share from 7% to 13% between 1980 and 1999 mostly at the expense of hydro whose share fell to 14% from 21% over the same period. The only region where hydro generation appears to have expanded is Eastern Europe and FSU. But, the increase in hydro's share from 13% to 17% between 1980 and 1999 is partially due to economic collapse of the region in the 1990s, which resulted in the production and use of oil and gas. The generation from conventional thermal fell from 1,309 billion kWh in 1980 to 1,000 billion kWh in 1999, resulting in a decline in the share of these fuels from 82% to 66%. Another reason for this decline is the expansion of nuclear generation from 5% to 16%.

In Central and South America, hydroelectricity continues to dominate with an increased share of 70% in 1999 as compared to 65% in 1980. Almost all of the remaining generation comes from conventional thermal facilities that use oil products or natural gas, which is increasing its share at the expense of oil products. In the Middle East and Africa, practically all electricity is generated at conventional thermal facilities – 96% in the former and 80% in the latter. Africa's second largest source of electricity generation is hydro facilities, accounting for 17% of total in 1999, down from 32% in 1980.

Markets

Functions of Spot and Futures Markets

Markets for energy commodities, like those for other commodities, have two functions. First, they provide a medium for discovering the market-clearing (or, equilibrium) price for oil, natural gas and products. Second, they render the transfer of stocks from the current period to future periods possible. According to these two types of trade, there are basically two types of trade in these markets: (1) one based on the immediate delivery handled by "spot" markets, and (2) another based on delivery at some future date carried out through "forward" and "futures" markets. The difference between current and future prices provides a good signal about market conditions. The spot price will tend to be higher than futures (or, forward) prices if inventories are perceived to be tighter in the near future relative to long-term expectations (this is known as "backwardation"). For example, during the Gulf Crisis following the invasion of Kuwait by Iraq, spot prices increased significantly relative to prices for contracts in 6 to 12 months into the future with expectations of

a particularly harsh rally combined with the supply disruption. More routinely, the forward curve for gasoline prices will indicate backwardation in late spring or early summer as driving season puts pressure on refineries and storage capacities. Similarly, forward curves for natural gas price will indicate a declining trend as people expect the demand for natural gas to fall as the heating season comes to an end in few months. Normally, however, that forward curves can be more volatile, especially on the demand or supply side (or both) that can change these seasonal patterns.

Alternatively, the futures price may become larger than the spot price if current inventories are considered plenty but a decline is expected in the long-term (this is known as "contango"). For example, during 1986, increased production from Saudi Arabia and others lowered prices considerably and raised inventories in consuming countries that took advantage of low prices. As markets did not expect excess supply situation to continue, futures price moved higher than spot price. Another common contango forward curves can be observed in fall months for gasoline or in summer months for natural gas. As before, unexpected developments can change these trends influenced by regular seasonality expectations.

History of Spot and Futures Markets

Historically, most crude oil and products were traded on the world market under long-term contracts at "official" prices of exporting countries. Although spot markets for oil existed since the 1960s, only after the first oil shock, they started to claim a larger share of the trade. Trading in spot markets accounted for only 3 to 5% of the total trade before 1980, but this share reached 50% internationally and 20% in the U.S. during the first half of 1980s. The shift to spot markets was anticipated by the collapse of the oil shock accompanying the Iranian Revolution that rendered the contract prices unreliable. The contract prices started to be adjusted so frequently that they became vulnerable to changes in market prices. After the crash in 1986, major oil exporting countries adopted "formula pricing" which tied contract prices to spot prices, calculating the futures price of spot price plus an adjustment factor, which considered quality differences, sources, destinations and shipping distances. For example, Saudi exports to the U.S. were priced based on the U.S. Gulf Coast spot price of Alaskan North Slope (ANP) until 1994, and on the Western Texas Intermediate (WTI) since then. The spot price for WTI is usually considered to be following its futures price, which we will discuss next.

In March 1983, the New York Mercantile Exchange (NYMEX) introduced trading in a crude oil futures contract with delivery of light sweet crude oil at Cushing, Oklahoma. Heavy sweet crude oil and gasoline contracts were introduced earlier in 1978. All these contracts have very specific definitions in terms of quantity, quality, and delivery conditions (available at www.nymex.com). This standardization and the clearinghouse role played by the exchange makes trading at NYMEX, and other established exchanges, much safer than over-the-counter trading arrangements and more transparent for all market participants. Although several streams are deliverable (including U.K. Brent, Norwegian Ekofisk, Algerian Saharan, Nigerian Bonny Light, etc.), the futures contract for crude oil tracks WTI light. During the first year, daily crude oil futures trading has risen as high as 10,000 contracts and averaged around 6,000 (one contract involves the purchase or sale of 1,000 barrels).

The success of the NYMEX experiment and the ending of official pricing by OPEC initiated the formation of a futures market for U.K. Brent at International Petroleum Exchange (IPE) in the late 1980s. Unlike the NYMEX contract, the British crude oil contract is cash-settled and pays interest on the contract rather than physical delivery, but instead tracks the Brent forward contract and employs cash settlements. In 2002, the volume of light sweet crude oil contracts traded in NYMEX range from 100,000 to 150,000 contracts for just few front months. Near-month contract volume is most significant ranging from 40,000 to 90,000 contracts a day. Open interest can be more variable ranging from as low as 30,000 or as high as 150,000 contracts for just the near-month contract. At the same time, trading in Brent crude can reach an average of about 50,000 contracts and an average open interest of over 150,000 contracts. The volume of trade in these futures markets can reach levels that are two or three times as large as the actual oil consumption in a given day.

The fact that these futures contracts reached such volume and share of the market in relatively short period of time is significant, especially considering that there are about 100 trading institutions including spot, futures and informal market contacts in the world. However, the NYMEX and IPE oil futures prices as global benchmarks. The electronic trading at NYMEX through NYMEX ACCESSSM allows traders around the world to buy or sell even when the exchange is closed. According to the NYMEX, the contract traded ("heavy" within the region, not relative to overall trade) in Asia such as Dubai, Malaysia or Tapis are priced by adding fairly fixed spread to final closing price of WTI. The spread is changed by WTI, although it does not have as much importance for the world as the crude oil and products trades, natural gas trading at NYMEX is very significant for the North American market. After the restructuring of the natural gas market in the 1990’s, NYMEX introduced the first formal natural gas contract with Henry Hub in Louisiana as the reference point in the early 1990s. 100,000 contracts a day are traded just for the few front months. Open interest can be 200,000 contracts for the same months.
Characteristics of Spot, Forward and Futures Markets

Spot Markets:
Transactions in spot markets involve the delivery of oil within two to four weeks of closing the deal. Two to four weeks may seem long for an exchange considered "current," but moving large volumes of oil over long distances may take that long. Contracts in spot markets are uniform in quality, quantity and terms in order to make transactions simpler and less costly. Transactions may occur any time of the day between parties located anywhere in the world.

Forward Markets:
Unlike spot markets, forward markets administer transactions of contracts with future deliveries. No cash is required at the time of transaction, and contracts are mostly settled by cash payments before the expiration of the contract without the need for physical delivery. The transaction involves a seller is direct without an intermediary body. Forward markets are used as a hedging device. For example, in order to avoid potential increases in the cost of oil, a refiner may prefer purchasing its future feedstock at current prices.

Futures Markets:
Similar to forward markets, futures contracts involve delivery at some time in the future and therefore serve as another hedging device. Unlike forward markets, payments are made at the time of transaction. Also, the inclusion of a clearinghouse (operated by the futures exchange) between a buyer and a seller makes changing positions (“short” versus “long”) easier for traders. A trader in short position can change his/her position by buying futures. Alternatively, a long position can be altered by selling futures. These transactions do not require the consent of the buyer and the seller of original contracts as transactions are carried out through the clearinghouse. Because of the ease of changing positions, futures markets have become primary modes of hedging. Every day, producers sell futures to protect against future declines in the price of oil, and consumers buy futures to protect themselves against price increases in the future.

In all of these markets, there are primarily three types of players: hedgers, speculators and arbitragers. Those who employ forward or futures markets for hedging purposes tend to be price level sensitive and concerned about market movement against them. These tend to be asset owners rather than the production or consumption side. They prefer few long-term transactions to protect themselves against unfavorable price movements in the future. Speculators, on the other hand, benefit from volatility of prices; they undertake many short-term transactions, trying to buy low and sell high and not hold any positions for too long. Finally, arbitragers try to take advantage of differences in prices across different regions, different time periods or different fuels. The role of creating liquidity in the marketplace and hence increasing the accuracy and value of price signals.

Forecasting Long-Term Crude Oil Prices:
Since the first oil shock, forecasting the price of oil has proved to be quite challenging. Researchers from the academia or the industry and organizations such as the U.S. Department of Energy (DOE) and the International Energy Agency (IEA) have undertaken various forecasting analyses. Historically, however, forecasts have failed significantly in accuracy. The following chart presents four price forecasts from different periods performed by the DOE. For comparison purposes, the actual price is also presented.

Historical Price of Crude Oil and Price Forecasts:

Forecasts indicate that prices are expected to increase at a significant rate after the second oil shock (1982 forecast), but also after the crash of oil prices (1986 and 1988 forecasts). The expected source theory (see Chapter 9) implies such an increase in the price of exhaustible resources as their cumulative production rises. However, we also discuss the flawed assumptions of the model leading to the conclusion of rising prices. For example, the model does not allow for reserve additions. However, the additions to resource base have been very significant since the 1970s and remain a crucial factor affecting the accuracy of predictions about future supply of oil. Forecasters also failed to incorporate into their models technology development that enhanced production from existing fields. The effects of conservation and efficiency programs, and those of increasing role of alternative fuels were not assessed properly, either. In retrospect, one can also claim that, in the 1970s and 1980s, forecasters overemphasized or misinterpreted the power of OPEC. All of these led to an underestimation of the world oil supply. When combined with usually overestimated demand, it is no wonder we ended up with increasing price forecasts.

However, the failure of forecasts in the past does not imply that forecasting cannot be used. The future price of oil has significant implications on evaluating oil projects. The decision makers would very much like to know future price trends with as much accuracy as possible. Forecasting can be very helpful in that area if it is carried out with meticulous attention to every relevant variable. Futures trading in established exchanges, where numerous stakeholders buy and sell contracts, provide fairly dependable indication of future prices at least for the next six months to a year.

The Role of International Organizations:

Organization of Petroleum Exporting Countries
Organization of Petroleum Exporting Countries (OPEC) was formed by Venezuela, Saudi Arabia, Kuwait, Iran and Iraq in 1960. At that time, these five countries owned about 67% of the world’s proved oil reserves, and produced over 37% of the world’s oil, their intention was to influence the price of crude oil. The relatively small increase in OPEC’s production was modeled after previous efforts of output management in the U.S. such as the Texas Railroad Commission and the Interstate Oil Compact Commission. In particular, the impact of forming an oil cartel (Texas, Oklahoma, Louisiana, Kansas and Illinois) provided an example of an intergovernmental organization for output management.

The rest of the OPEC members joined the organization during the 1960s and the early 1970s (Qatar, 1961; Libya and Indonesia, 1962; Abu Dhabi, 1966; Algeria, 1969; Nigeria, 1971; Ecuador 1973; Dubai and Sharjah, 1974; and Gabon, 1975). By 1973, the organization accounted for almost 75% of the world’s oil production and its share in production increased to 53%. The failure of the organization to maintain a successful quota system, and lower oil prices brought about by the crash in the mid-1980s increased frustration among some OPEC members. As a result, Ecuador, Gabon and Brazil withdrew from the organization in December 1992 and Gabon withdrew as of January 1995.

The unexpected four-fold increase in crude oil prices in December 1973, following the October war in the Middle East, has been widely attributed to the activities of OPEC operating as a cartel. Prices are accepted to be substantially higher than if they had been solely determined by market conditions and OPEC is accused of curbing production in order to raise prices. Significant increases in the price are usually matched with a considerable decline in OPEC production (see chart above). This is most apparent for the second oil shock period, where rising prices coincide with falling production by OPEC, including the most recent agreement among OPEC members in 1999-2000. Alternatively, the declining prices of the 1980s, especially the crash in 1986 coincides with significant increase in OPEC output. In early 1986, Saudi Arabia increased its output by more than three million b/d.

Over the years, especially after 1973-4, OPEC production declined while their reserves increased. In 1973, OPEC countries were responsible for 53% of total world production while they owned almost 70% of total world reserves. By 1992, the percentage of world reserves owned by the members of OPEC increased to 78%, while the production share of the organization fell below 40% after a historical low of 28% in 1985 (see chart below). Throughout the 1980s, the organization’s 11 members produced approximately 40% of the world’s oil. They own almost 80% of the world’s proved oil reserves. Obviously, the absence of Ecuador and Gabon did not affect the position of the world oil market since they owned about 2% of OPEC’s production. The increase in the share of OPEC in world’s oil reserves and the decline in its production have been consistent with the behavior of a cartel trying to keep the world price of oil high by curtailing its production in response to increasing non-cartel output. OPEC members also account for about 45% of the world’s gas reserves. Members in the Persian Gulf alone are estimated to hold more than 8,000 trillion cubic feet of gas (34% of the world’s proven gas reserves). Despite significant reserves, OPEC’s share in world gas production is only around 16% after increasing significantly in the late...
1990s. Half of this production comes from Algeria, Indonesia and Qatar. Gas production to reserves ratio in the Middle East is below 1%. However, this is quickly changing as significant resources are being allocated to development of natural gas fields by Qatar, Saudi Arabia and others in the region. The production of natural gas is projected to increase at about 6% a year during the next ten years. This rate can increase if Iran and Iraq can overcome international restrictions and finance their projects.

However, OPEC did not show the characteristics of a textbook cartel until the early 1980s when it adopted a quota system. The organization did not have an explicit policy of production or profit sharing, or policing devices to detect and punish overproducing members. The Arab-Israeli war and the accompanying oil embargo to the western world by Arab exporters in 1973-74, the revolution in Iran and the beginning of the war between Iran and Iraq at the end of the 1970s were events mostly outside the control of Saudi Arabia, and that had excess capacity, for example, in the late 1970s and early 1980s when Iranian and Iraqi production was not available to the world.

Also, the transfer of property rights from multinational oil companies to host governments that took place mostly in the 1973-4 period provided another vital change in the market. Perhaps most important of all, the rapid industrialization of the world in the 1960s increased the demand for crude oil. Alternative energy sources were considered scarce and costly. All these circumstances provided an opportunity for large producers to reap substantial benefits. The opportunistic nature of the organization was demonstrated by some members (e.g., Saudi Arabia) that did not fully compensate for the loss of output although they had the excess capacity, for example, in the late 1970s and early 1980s when Iranian and Iraqi production was not available to the world.

After OPEC adopted the quota system, however, Saudi Arabia quickly became the "swing supplier," reducing its production as necessary to balance supply and demand. The Kingdom rejected that role in mid-1985, when its output had fallen to about 25% of its 1980 peak of 10 million b/d, and increased its output to five to six million b/d range in a very short period of time. Increased Saudi supplies resulted in the price collapse of 1986. Prices did not return to the pre-1986 level until the Persian Gulf conflict of 1990-91, and then only briefly.

The collapse of the oil price in late 1990s, however, was a serious blow to the members of the organization. Most of them never diversified their economies; oil revenues are crucial for maintaining the health of the economy, level of social services and hence happiness of their societies. Historically low prices in 1997 and 1998 (at about $10 per barrel) hurt OPEC economies badly. In reaction, led by Saudi Arabia and with the help of some non-OPEC producers such as Russia, Mexico and Norway, the organization was able to implement and manage a quota system successfully. For the first time, OPEC announced a price band and managed production levels accordingly. Members obeyed their cuts for a sustained period of time. Together with the recovery of the world economy from Asian crisis, oil prices recovered in late 2000 and 2001. But, as oil prices stayed high and world demand continued to increase, members stopped following quotas, and cooperation of non-OPEC producers ended. Clearly, the organization, and especially Saudi Arabia, has the potential to impact the price of oil but doing so requires extreme conditions to convince other producers to cooperate and is not sustainable once those conditions disappear.

What can we expect from OPEC in the future? In general, for producer cartels to operate successfully over the long run, a number of "rules" apply. For one, it helps if the commodity in question is homogenous in quality. Second, the more concentrated the commodity is geographically, the easier it is for producer associations to form and organize. Third, cohesion within the producer association is essential, and difficult to achieve and sustain. Fourth, the easier it is for consumers to reduce their demand for a commodity, either through substitution or conservation, and the easier it is for new producers to enter the industry (partly a function of geographic allocation of the commodity and homogeneity), the more difficult it is to sustain cartel activity.

The upshot is that for a number of commodities in which various forms of producer collaboration and organization have been tried, success is difficult to achieve and sustain (see chart above at left). Over a long period of time, prices for a basket of commodities have declined rather than increased (the usual goal for producers). Despite all its problems described earlier, OPEC has been one of the more successful cartels, outperformed only by the DeBeers diamond cartel. The relative cohesion within OPEC since institution of the price band for the OPEC crude oil basket in 2001 has been remarkable by historical standards for both the association and the history of cartels in general. OPEC’s dominance in the global oil market is, however, increasingly challenged by the Former Soviet Union producers (in particular Kazakhstan and Russia), which will increasingly test cohesion of the cartel in future years. A key balancing mechanism in the battle for market share will be demand for crude oil in the large emerging markets of China and India.
International Energy Agency

The International Energy Agency (IEA) is an autonomous body within the framework of the Organization for Economic Cooperation and Development (OECD) that was established in November 1974, in response to the first oil shock, to implement an energy program that would provide energy security for its members. In those days, governments were most concerned about receiving uninterrupted oil supply. One of the immediate actions taken was to create oil inventories in order to avoid the economy-wide impact of another oil shock. The IEA has 23 members (as compared to 27 members of the OECD). Its basic goals are:

1. to operate among IEA participating countries to reduce excessive dependence on oil through energy conservation, development of alternative energy sources and energy R&D;
2. an information service on the international oil market as well as consultation with oil companies,
3. cooperation with oil producing and other oil consuming countries with a view to developing a stable international energy trade as well as the rational management and use of world energy resources in the interest of all countries,
4. a plan to prepare participating countries against the risk of a major disruption of oil supplies and to share available oil in the event of an emergency.

Although these activities remain fundamental for the IEA, the Agency extended its operations and focus to emerging markets, especially in Asia. These countries are expected to account for more than half of the world's energy demand early in the next century. The increased consumption of fossil fuels and reliance on nuclear power in order to avoid dependence on imported oil are already causing environmental concerns. Also, the emergence of Central Asia and, to a certain extent, Latin America as potentially significant suppliers of oil and gas has changed the structure of the world energy markets.

Recently, the IEA started to assist non-member countries in developing energy strategies and adopting energy policies that will contribute to their economic development and enhance global energy security. Liberalization of the marketplace is considered a priority by the Agency, which suggests building transparent and open markets and increasing competition through privatization and less government intervention. This will attract foreign investment and consequently economic development. The impact of international energy trade on domestic policies has long been a source of conflict. The following diagram shows why.

### How International Trade Challenges Domestic Regimes

International trade flows across national boundaries, driven by comparative advantages, create pressure for host governments to accommodate global trade laws, regulatory frameworks that complement private investment and reduce barriers to entry via open access. Balancing these pressures is the relative strength of state ownership and control. When states act to protect incumbent interests, international trade flows are disrupted. Generally, the strongest trade regimes are those with significant barriers to entry. In effect, international trade impacts internal policies and politics – and thus the derivation of conflict.

Examples of prevalent international trade regimes that affect energy include the World Trade Organization (WTO) negotiations for services; the North American Free Trade Agreement (NAFTA) which binds Canada, the United States and Mexico; the European Union which binds 25 countries from west to east Europe; El Mercado Común del Sur (Mercosur) which binds Argentina, Brazil, Paraguay and Uruguay; Association of Southeast Asian Nations which binds ten countries; and a variety of regional trade arrangements in Africa (SADC, Southern African Development Community; COMESA, Common Market for Eastern and Southern Africa; SACU, Southern African Customs Union; CBI, Cross-Border Infrastructure Initiative; EAC, East African Community; ECOWAS, Economic Community of West African States; COMESA; ASEAN, Association of Southeast Asian Nations; SACU, Southern African Customs Union; SADC, Southern African Development Community; WAEMU, West African Economic and Monetary Union). In addition to global and regional trade regimes, countries often engage in bilateral or bilateral-to-multilateral arrangements.

A key question is whether international trade regimes lead to harmonized rules with respect to energy. For example, a set of practices that link energy value chain economics and policy/regulatory frameworks for successful, commercial investment and project development – what we term “commercial frameworks” – includes, for example, the safeguards and use of energy sector development and management can be facilitated through trade regimes. The illustration of relationships between trade and domestic policies dictates the extent to which best practices will be fully shared and implemented. The relative level of overall development of countries also has a substantial impact. Energy sectors that are comparatively undeveloped may not be best served by commercial frameworks designed for more advanced countries and markets. To the extent that domestic policies reflect unique socioeconomic, political and cultural histories and traditions within countries, harmonization of rules can be difficult to achieve. The North American and European Union market are strong cases in point. That said, there is little doubt, and strong empirical evidence, that international trade exerts at least some degree of impact on domestic regimes and at least incremental movements toward emerging international standards for private investment and access.

### Industry and Government Associations

Energy is often a sensitive and complex subject, and energy sector development – including the regulation of energy services; the exchange of goods to use energy resources in the interest of all countries, – is not an easy undertaking. In the global context, numerous industry and government associations, as well as professional societies and standards organizations and societies coordinate and intellectual property, access, investment, capital flows, research and development, policy/legal/regulatory best practices and the like. Some of the more prominent associations include the World Energy Council and World Petroleum Council; large energy trade associations that span the international arena, such as the International Gas Union, American Petroleum Institute and Edison Electric Institute; the large professional societies that spur collaboration among the core science and engineering disciplines, such as Society for Petroleum Engineers, American Institute for Chemical Engineering, Society for Exploration Geophysics, American Institute of Petroleum Geologists and the International Association for Energy Economics; government associations like the National Association for Regulatory Utility Commissioners, the Canadian Association of Municipalities and their American, European and Asian counterparts and many others. These organizations engage in bilateral or bilateral-to-multilateral arrangements. Bilateral and multilateral lending and financial institutions also serve to coalesce international and regional energy interests. The World Bank and the various regional development banks are not small players in global energy investment flows, trade flows, energy sector restructuring and evolution of commercial frameworks. The United Nations also has impact through the various UN agencies and programs that address energy, environment and infrastructure. These institutions and many others within the global and regional energy community of interest are participants in the emerging International Energy Regulators Network.

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Economies of scale can rapidly develop, especially with application of information technologies in wholesale and retail markets. In many cases, energy businesses seek to expand economies of scale and scope, using market share as protection against new entrants. From an energy business perspective, integration is a key mechanism to insulate the firm against volatile commodity price cycles. Governments often accommodate market power in the energy sector through regulated entry or access and regulated pricing to reduce the opportunities for monopoly power and other forms of market failure (see chapter on role of government later in this section). The constant tension in highly networked, value chain driven industries is the tendency for competition to rapidly decline profit margins, triggering strong incentives for industry consolidation. Thus, a critical balance between energy industry activity and government actions to protect public interest must be achieved to facilitate energy sector investment. Best practices in commercial frameworks (the rules and norms created by governments to facilitate commercial activity) are all about achieving this critical balance, while also being mindful of the many issues (access, transparency, public involvement, environmental protection) that impact energy development.

CHAPTER 3
OIL VALUE CHAIN

Introduction
Fossil fuels (oil, natural gas and coal) make up roughly 88% of the world’s primary energy consumption, while oil accounts for 38% of the global primary energy consumption (see chart below). Oil is expected to remain the dominant energy fuel for the world for the foreseeable future. Oil is an important part of our everyday life. Oil gives us mobility, fuels many industries and provides electricity. Millions of products are made from oil and natural gas, including plastics, medications, clothing, cosmetics, and many other items you may use daily. However, most important use of oil is in the transportation sector. n the U.S., 97% of the energy that drives the transportation sector (cars, buses, trains, airplanes, etc.) comes from fuels made from oil.1 Auto manufacturers are developing cars to run on alternate fuels such as electricity, hydrogen and ethanol. However, the electric batteries need to be charged and the fuel to generate the electricity could be oil or gas. The hydrogen needed for fuel cells could also be generated from natural gas or petroleum-based products. Even as alternative fuels are developed, oil remain crucially important to assuring that people can get where they need to be and want to go for the foreseeable future.

World Primary Energy Consumption 2002

In the industrialized world, increases in oil use are projected primarily in the transportation sector, where there are currently no available fuels to compete significantly with oil products. In the developing world, oil consumption is projected to increase for all end uses. In some countries where noncommercial fuels have been widely used in the past (such as fuel wood for cooking and home heating), diesel generators are now sometimes being used to dissuade rural populations from decimating surrounding forests and vegetation, most notably in Sub-Saharan Africa, Central and South America, and Southeast Asia.

As economies around the world continue to grow, businesses and emerging middle classes are demanding greater mobility for both personal and commercial purposes. Even as alternative fuels are being developed and commercialized, oil remain crucially important in the near future.

CHAPTER 3
OIL VALUE CHAIN

Key Segments and Activities
The key segments of the oil value chain are exploration and production, transportation, refining, distribution and marketing. The segments can also

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be divided into upstream and downstream. Upstream activities are closer to the crude oil source, and "downstream" activities, such as distribution and marketing of refined products, are closer to the consumer. Sometimes, crude oil transportation and refining are classified as midstream.

Crude Oil Value Chain

- **Upstream**
  - Exploration
  - Production
  - Transportation
  - Refining
  - Midstream
  - Downstream

Exploration
The activities that lead to discovery of new natural crude oil resources. Exploration risk is one of the strongest forms of risk.

Production
The extraction of discovered supplies from hydrocarbon fields. If there is associated natural gas, it must be separated.

Transportation
There are two modes of transportation for inter-regional trade: tankers and pipelines. Tankers have made global (intercontinental) transport of oil possible, and they are low cost, efficient, and extremely flexible. Pipelines, on the other hand, are the mode of choice for transcontinental oil movements.

Not all tanker trade routes use the same size ship. Each route usually has one optimal economic size based on voyage length, port and canal constraints and volume. Thus, crude exports from the Middle East, high volumes that travel long distances, are moved mainly by Very Large Crude Carriers (VLCC's) typically carrying over two million barrels of oil on every voyage. In contrast, ships out of the Caribbean and South America to the U.S. are routinely smaller and enter ports in the U.S. directly. Because of such ship size differences, a long voyage can sometimes be cheaper on a per barrel basis than a short one.

Pipelines are critical for landlocked crudes and also complement tankers at certain key locations by relaying bottlenecks or providing shortcuts. Pipelines are the primary option for transcontinental transportation, because they are at least an order of magnitude cheaper than any alternative such as rail, barge, or road, and because political vulnerability is a small or non-existent issue within a nation’s border or between neighbors such as the U.S. and Canada. Pipelines are also the most important mode of transport in mainland Europe, although the system is much smaller in view of the shorter distances.

Refining: Refining is a complex series of processes that manufactures finished petroleum products out of crude oil and other hydrocarbons. While refining began as simple distillation, refiners must use more sophisticated additional processes and equipment in order to produce the mix of products that the market demands.

Distribution and Marketing: Delivery of refined products via pipelines, trains, and trucks for retail marketing by gas stations, fuel oil companies and other marketers.

Key Policy and Regulatory Considerations
Clearly, crude oil is traded in a global market with numerous players with a wide variety of demand- supply characteristics. As discussed in Chapter 3, OPEC can have significant influence on the price of oil. In most resource rich countries, national companies dominate the sector. There is also considerable geopolitical risk. Considering the major export region for oil is the Middle East. Given these risks and importance of oil in economic development, consumer governments usually follow policies targeting supply security. By diversifying their suppliers, they manage geopolitical risks. Building fuel substitution capability wherever feasible and increasing demand side response via energy efficiency and conservation programs also help economies absorb supply shocks. Many countries also hold petroleum reserves (see the section on IEA in Chapter 1).

On the supply side, the biggest challenge is the ability to invest in resource rich countries under commercially viable terms. In many countries, access to upstream by private investors is either not allowed or very limited. In others, investment infrastructure is not acceptable (see below for more discussion of this topic). In addition, both buyers and sellers may impose restrictions. For instance, the U.S. prohibits imports from Iran and Libya, and the United Nations allowed only limited sales of Iraqi oil during the 1990s. On the seller’s side, Mexico formerly limited sales to the U.S. to 50% of its exports, reflecting concerns about dependence on the U.S. specifically and about allowing only limited market penetration. Saudi Arabia’s national security concerns, on the other hand, dictate that it maintain a very high profile as a supplier to the U.S. market, even at the cost of lower netbacks.

In most developed countries, activities across the oil value chain are mostly unregulated. There are not much economic regulations on crude oil or, for the most part, its products. Most emerging and least developed economies, though, continue to employ subsidized pricing for fuels such as kerosene or LPG that are used by the poor for cooking and heating. It is also possible to observe subsidies for distillates used in industry or power generation. National companies play an important role in administering or benefiting from these programs. However, the industry is the target of taxes that are imposed primarily for the purpose of raising funds for governments, especially in developed countries. Some of these funds may be used in building and maintaining finance other projects. A part of these taxes can also be said to represent the cost of externalities associated with oil consumption, e.g., emissions from tailpipes. The chart above demonstrates the wide range of tax policies pursued by a group of OECD countries. While taxes account for less than one third of total price of gasoline in the U.S., they make almost three fourths of the price in the UK. The U.S. is a large country and its economy is very much dependent on low-cost transportation of goods and services as well as people. On the other hand, the UK is a small island where land transport does not constitute a major cost item for most businesses or individuals.

The oil industry is also subject to a variety of operational safety, health and environmental regulations. For example, because of the tailpipe emissions, gasoline consumption is a major contributor to air quality problems, especially in large cities. Governments around the world employ different approaches to lowering the level of emissions. Some limit access to cities by all vehicles (e.g., alternating days based on license plate numbers); others impose fines for entering congested areas of the city (e.g., the recent experiment in London); but most common is the regulation on fuel specifications. The simplest action involves switching to unleaded gasoline or cleaner burning LPG or CNG; but reformulation of gasoline can become very complicated and expensive for both refiners and consumers. For example, there are as many as 18 different kinds of gasoline specifications that exist throughout the U.S.

This greatly hinders market flexibility, as the lack of a uniform specification prevents gasoline from moving from one region to another. Furthermore, some U.S. regional markets such as the West Coast and the Midwest generally function in isolation, which only increases the risk of shortages. Recently, more stringent regulations mandated the lowering of sulfur content to 120 parts per million (ppm), and the elimination of oxygenate and octane enhancer methyl tertiary butyl ether (MTBE). The replacement of MTBE with ethanol in the reformulated gasoline market led to a reduction in the entire U.S. gasoline supply, as ethanol has to be blended with smaller quantities of gasoline to avoid a high level of volatile materials that breach the new restrictions. Differences in fuel specification can also lower the liquidity in global trading of products.

Investment in the Oil Value Chain
The cost of finding and producing crude oil can range from as little as $2 per barrel in the Middle East to over $55 per barrel in some fields in the U.S. The range is so wide because there is great uncertainty about existence, quality and size of oil reserves. Finding oil involves a series of steps: identifying a prospect, drilling a well, appraising the size of the discovered field and determining whether the find is commercially viable. Production wells are then drilled and gathering pipelines are assembled to transport the oil to central points for further shipment. These are all very capital-intensive activities. As such, the upstream segment involves the most investment risk. Accordingly, it provides greater rewards in terms of profit and return on investment than other segments of the value chain. Between 75 and 80 percent of the crude oil ultimate value is captured in the upstream segment of the value chain. Recent technological advances have reduced the uncertainties and contributed to more efficient use of capital, enhancing the industry’s success, even in a low-price environment.

Technological innovation not only makes it easier to find new deposits of
oil and gas, but to get more oil or gas from each reservoir that is discovered.

In order to fuel growing world economies, led by China and the U.S. and closely followed by India and other emerging economies, there is a need for significant investment in the near future. Part of the urgency is a result of the bust experienced after the collapse of oil price in late 1990s following the Asian economic crisis and ill-timed IEA decision to increase quotas. Companies cut their investment budgets and many expensive fields in mature regions such as the U.S. stopped producing. According to the International Energy Agency (IEA), total investment needed between 2021 and 2030 is roughly $3 trillion, most of which will be for exploration and development activities.

A number of issues will impact this investment outlook. The reduction in capital spending for upstream activities as the international oil industry continues to consolidate after the tough times in late 1990s. Large producing basins (e.g., in North America and North Sea) mature. Perhaps more importantly, governments of most resource rich countries (and large national companies) continue to constrain entry by international companies. Moreover, there has been increased concern over the reserves of most Middle Eastern producers. Since these countries upgraded their reserves numbers by almost 300 billion barrels in the late 1980s, there has not been significant international investment in these countries and not many new field developments. As the world oil market becomes tighter, the veracity of these reserves and the investment needed for their development become more important topics of debate.

### Investment Requirements in the Oil Sector ($ Billion)

<table>
<thead>
<tr>
<th>Exploration &amp; Development</th>
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<tr>
<td>Unconventional Oil</td>
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<tr>
<td>Refining</td>
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<td>Pipelines</td>
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<td>TOTAL</td>
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<td>$1,045</td>
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**Source:** International Energy Agency

In particular, Saudi production capacity has been attracting a lot of attention. According to the analysts, Saudi oil production from existing fields may be near peak and next generation of Saudi oil will be harder and hence more expensive to extract. It is important to understand Saudi potential well because the Kingdom produces roughly 10% of world’s oil (roughly eight million b/d) and is the only producer with significant refining capacity (estimated at about two million b/d). The EIA, IEA & OPEC forecasts are consistent: by 2010, oil demand will reach about 90 million b/d, which requires the addition of about 8 million b/d in extra production capacity. By 2020, forecasts diverge but range between 104 (IEA) and 110 million b/d (EIA and OPEC), indicating an additional increase of production capacity by 14-20 million b/d. According to the EIA, Saudis will need 13.6 million b/d in 2010, and 19.5 million b/d in 2020. Aramco officials at the CSIS meeting claimed that the Kingdom could produce up to 15 million b/d. Saudis can produce up to 12 million b/d for some time and no more.4 Even if the gap between IEA expectations and Saudi production estimates can be closed, that would require significant amount of investment to flow into the Kingdom starting fairly soon. But the Kingdom has been closed to international investment in upstream oil since 1970s. There seems to be no indication for a change in this policy and Aramco’s ability to raise the financing is debatable.

### The Link between Investment and Commercial Frameworks

**Global Perspectives**

There is more trade internationally in oil than in anything else. This is true whether one measures trade by volume, by value, or by the capacity of the pipeline. Generally, markets are oversupplied, albeit very temporarily. These cycles damage the industry's ability to create the excess supply conditions of the future, contributing to the volatility of oil prices.

Naturally, major economies sometimes permanently. These cycles damage the industry’s ability to attract and keep high quality employees from management to engineering and to field operations.

**The Link between Investment and Commercial Frameworks**

**Commercial Framework Principles for the Oil Value Chain**

As discussed before, approximately three fourths of the value chain are generated in the upstream. This is the riskiest investment in the industry; accordingly, investors require higher rewards. Since oil, like many other natural resources, are treated as national by many countries, state companies and policies dominate the sector, private investment is restricted. Where it is allowed, commercial frameworks are not always conducive to investment. General observation over the past decades is that if the base is (i.e., lower the technical risk is), the tougher the fiscal terms offered by countries become; in Chapter 6 we provide a detailed discussion of this relationship and in Chapter 9 we provide more background on fiscal terms. In addition, legal and regulatory infrastructure may not be sufficiently evolved to support such large investments. Petrostate laws may provide all sort of support and investment incentives; policies of the government can be unstable. The legal system may limit contract dispute resolution. All of these increase the uncertainty of investment. Of course, OPEC and, in particular, Saudi Arabia continue to manage the oil market by adjusting the output of the organization. Most recently, OPEC has been administering a price band with some success (see Chapter 2).

Increasingly, these large scale investments attract the scrutiny of environmental and human rights NGOs who put pressure on companies, governments, and international agencies to undertake numerous studies to assess environmental and social impact of the pipeline.

**Relevant Case Studies:**

- **Brazil’s Restructuring of the Oil & Gas Industry Chad Cameroon Pipeline**

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NATURAL GAS VALUE CHAIN

Natural gas has come a long way as a good with intrinsic value. Natural gas was once considered a mere byproduct of oil and thus not worth the significant capital investment required to find, gather, treat, transport and distribute this resource. The relative abundance, wide dispersion and cleanliness of natural gas has propelled it to the forefront of the fossil fuels so that natural gas today is poised to become a global commodity, a bridge fuel to the next energy future and a source of molecular building blocks to new materials. The key policy challenges lie in differentiating the various markets, associations and the methods for fashioning property rights allowing cost-effective supply, demand and pricing mechanisms; designing appropriate policy approaches for components of the natural gas value chain that bear public social access attributes and the public policy of trans and mobilizing capital investment while balancing efficiency and equity concerns.

Whereas oil is a global commodity, transported in a variety of ways, and with consistent pricing in dollar terms, natural gas tends to be a regional fuel. The use of natural gas is limited by transport options – pipeline for overland delivery, ship for transoceanic delivery as liquefied natural gas (LNG). Natural gas is also traded in currency denominations according to location of use. Thus, natural gas is not yet considered to be a fungible, global commodity, like oil. Because domestic use of natural gas tends to be dominated by pipeline transportation and distribution of methane, both of which may tend to have natural monopoly characteristics, much of the natural gas business has been characterized by state intervention in various forms to manage market power and protect the public interest. Broad experimentation with competitive markets for natural gas since the mid-1980s has yielded a variety of results and many lessons, as well as hasty experimentation at the corporate level. The power of the natural gas value chains are the essence of best practices. These supply security “premise” for natural gas should be no different than for the energy sector overall, or for other specific fuel markets. In general, the greater the degree of demand, the lower the geographical risk. This is particularly important because natural gas prices in many parts of the world remain strongly linked to oil, a result of interchangeability for these fuels and the lack of separate markets. Rather than separate “demand side” considerations, they should be incorporated into the supply portfolio. To the extent that policy and regulatory approaches provide for choices to be made with regard to natural gas consumption, then demand will adjust to changes in supply and thus price, enabling imbalances to be rationalized. Price signals transfer information, facilitating choices. A specific political issue in many countries is the degree to which customers should be, or can be, exposed to price volatility. It is clear, from a number of instances around the world, that minimal political interference is best, but political willingness to support “light handed” policy and regulatory regimes is a distinct limitation.

These supply security considerations lead to the realization that flexible, transportable versions for private investment and operation across the natural gas value chains are the essence of best practices. These approaches facilitate price discovery, spur technological innovation for both supply and demand, and provide for midstream hedging solutions such as storage, a key ingredient to ensure supply-demand balances.

Natural gas is an important and rich source of energy for the world, but the physical characteristics of this fuel source, the economic features of the natural gas value chain and its extension to electric power as gas-fired power as a prominent strategy pose particular challenges to investors (suppliers) and their customers. Natural gas transportation options tend to be constrained, with pipeline transportation and distribution the dominant mode. Within domestic markets, there must be sufficient demand and “willingness to pay” in order to justify investment in transportation and distribution infrastructure. For gas to become a “global” fuel like oil (as liquefied natural gas or LNG; through gas-to-liquids or GTL conversion; or some other strategy), there must be sufficient size for conversion of natural gas to other products, LNG is an important means of deriving value for their natural resource endowments through international trade. LNG as a domestic energy source has also grown, proving to be a relatively cheap (in terms of local infrastructure) and clean replacement for biomass. In particular, LPG has replaced wood (and is therefore preferable in places where deforestation has been rampant) and animal dung.

Worldwide, the natural gas industry has grown rapidly in recent years. Nations with rich natural gas resources have aggressively added new petrochemicals capacity. These huge investments tend to be quite lumpy and the products subject to intense global competition (with commensurate impacts on the feedstock molecules), leading to the well-known cyclicalities in these businesses. Likewise, LNG investments are also sizeable, lumpy and subject to global forces, and also fast growing. For nations that do not have large enough domestic demand relative to size of their resource base, or that have not developed petrochemicals capacity for conversion of natural gas to other products, LNG is an important source of revenue for their natural resource endowments through international trade. LPG as a domestic energy source has also grown, proving to be a relatively cheap (in terms of local infrastructure) and clean replacement for biomass. In particular, LPG has replaced wood (and is therefore preferable in places where deforestation has been rampant) and animal dung.

LPG also represents an improvement in both cleanliness and safety over kerosene, also used as domestic fuel. Where LPG is in wide use, typical domestic “fuel” is propane/butane. Where LPG is in wide use, typical domestic “fuel” is propane/butane. In many countries, particularly those with short heating seasons, LPG comprises the principal domestic fuel source for water heating and cooking.

Natural gas liquids (NGLs) – ethane and larger molecules – also are stripped out as feedstocks for petrochemicals (methylene can also be used for petrochemical applications, but much larger volumes of methane are required than for the heavier molecules). These molecules can also be transported by pipeline, truck or tanker. Other than pipeline delivery, methane can be liquefied and thus transported economically over large distances (in liquefied natural gas or LNG ships or by truck; LNG cargos may contain molecules other than methane if there is no processing at the point of liquefaction). Or methane can be compressed (compressed natural gas or CNG) and transported short distances by truck and eventually, depending upon emerging of viable technologies and cost structures, in CNG tankers. CNG and LNG allow methane to be used as a vehicle fuel where LNG can be used directly.

Key Segments and Activities

Generally, worldwide, natural gas/methane infrastructure systems consist of the following operational elements.


Exploration
The activities that lead to discovery of new natural gas resources. Exploration risk is one of the strongest forms of risk.

Production
Extraction of discovered supplies from hydrocarbon fields either with crude oil (as associated natural gas) or separately (non-associated natural gas). If natural gas is associated with crude oil, it must be separated.

Gathering
Collection of natural gas production from multiple wells connected by small diameter, low pressure pipeline systems and delivery to a processing plant or long-distance pipeline.

Processing and treatment (if necessary)
Processing is the separation of heavier molecules and unwanted substances such as water from methane gas stream. If the gas stream contains impurities such as hydrogen sulfide then treatment is required.

Storage
Containment of supplies, usually in depleted underground reservoirs or caverns like those associated with salt domes. Storage can be located either near production or near demand.

Transportation
Delivery of gas from producing basins to local distribution networks and high-volume users via large diameter, high volume pipelines. In countries that are federal republics, pipeline systems may be distinguished by whether they cross state or provincial boundaries (for example in the U.S., interstate pipelines as opposed to intrastate systems that operate within the state jurisdiction). Countries vary greatly with respect to allowable pipeline specifications for heat content, as measured by British thermal units (Btu) in the U.S., Canada and elsewhere, and as related to the presence of molecules other than methane in the piped gas stream. For example, pipelines transport and distribute methane and “wet” gas, as in Canada and the U.S. That is, heavier molecules are removed before the natural gas stream enters the pipeline system. Exceptions do exist, such as the Alliance Pipeline, which transports “wet” gas from British Columbia to Chicago, where molecules other than methane are stripped out in processing for use in other markets. Pipeline standards generally are set for safety reasons.

 liquefaction, shipping and regasification
Known collectively as the LNG value chain, this entails conversion of gas to liquid form via refrigeration to result in a cryogenic fluid (temperature - 250°F) for transportation from a producing country or region to a consuming country or region via ship. LNG is stored until it is returned to the gaseous phase at the receiving end and re-condensed (liquefied) for pipeline transportation within the consuming region. In the U.S., LNG is also used to store natural gas produced from domestic fields until it is needed, primarily for peak use. Both storage and transport of LNG are done at nearly atmospheric pressure.

Distribution
Retail sales and final delivery of gas via small diameter, low pressure local gas networks operated by local distribution companies or LDCs (often termed gas utilities).

End use and conversion
Direct use or conversion for use in other forms (petrochemicals, electric power or vehicle fuels).

The following commercial elements serve to bind the operating segments of the natural gas infrastructure system and link suppliers, transporters and distributors with their customers.

1. Aggregation : Consolidation of supply obligations, purchase obligations or both as a means of contractually – as opposed to physically – balancing supply and demand.

2. Marketing: Purchase of gas supplies from multiple fields and resale to wholesale and retail markets. Retail marketing constitutes sales to final end users (typically residential, commercial, industrial, electric power and public sector).

3. Capacity brokering: Trading of unused space on pipelines and in storage facilities.

4. Information services: Creation, collection, processing, management and distribution of data related to all the other industry functions listed here.

5. Financing: Provision of capital funding for facility construction, market development and operation start-up.


Key Policy and Regulatory Considerations
Altogether, the elements described above constitute the natural gas value chain. The various segments are highly interdependent but, in an open, competitive market, they also can be highly competitive. The policy challenges associated with increased worldwide use are numerous. Frameworks for high energy and transportation applications present a significant hurdle. Efficient and equitable mechanisms, often at odds, for pipeline transportation and local distribution are the second major hurdle.

Methane is of little use in consumer energy markets without pipeline infrastructure. These large systems tend to be characterized by strong technical economies of scale and high barriers to entry. Particular problems also emerge with respect to the purchase/payment component of these facilities, mainly with respect to reliability and pricing on systems that are usually operated in monopoly, duopoly or limited competition regimes. In an open, competitive market, it is generally not possible to achieve prices for natural gas transportation and distribution through tariff designs that yield something close to what competitive markets might be able to achieve, with reliability (or “open access”) usually providing a basis for market-based pricing in larger markets.

A third challenge is development of transparent markets for natural gas supply and consumption. If pipelines are an essential feature, a central question is whether molecules have intrinsic value or whether the combination of pipeline and molecule cannot exist without pipeline. If the two are commoditized, balancing supply and demand across a market becomes balanced by more efficient means of coordination and determination of activities and relationships across the value chain become established. The fuel’s growing importance in the international economy, as natural gas becomes globalized via LNG shipments and disparate national and regional markets become more integrated and integrated to the extent that they result in supply-demand imbalances which neither industry nor government can readily correct in a timely manner. Both the evolution of market-based policies for natural gas and international trade linkages mean timely and accurate data and information on supply, demand and prices, a fourth requirement.

A fifth and increasingly complicated challenge is dealing with integration, with respect to industry organization and international trade. Industry organization can encompass both vertical (meaning up and down the value chain) and horizontal (meaning over some geographic or market extent) integration. Paradoxically, the forces for integration within a natural gas industry often occur in spite of policy objectives that seek to instill de- integration and competition as part of transitioning to competitive markets. Integration of physical infrastructure across international boundaries has grown rapidly with increased demand for piped methane. As transportation and information technologies have advanced, so have the opportunities for system linkages – first within a country, then among geographically contiguous nation states and increasingly across the globe. With improved physical and commercial linkages comes an ever greater need for more complex, sophisticated and coordinated policy solutions, posing new dilemmas in international trade.

Investment in the Natural Gas Value Chain

In general terms, we speak of the challenges to build the “natural gas factory,” a concept that encompasses the importance of seamless investments across the value chain. Exacerbating the challenge is the fact that international investor goals have coalesced around the need to “monetize” natural gas production which has no current market outlets, that is, with the “stranded” or uneconomic to produce. To a large degree, gas monetization is being driven by the international financial community and by initiatives such as Global Gas Flaring Reduction5, especially in areas where natural gas is associated with crude oil production.


Investor Goals

Investor Goals

Commercialize natural gas production, by increasing diversity of market linkages

- Gaining access to downstream participation where supported by markets (‘power the world with gas’)

- Exit


Muhammad Firman (University of Indonesia - Accounting)
We estimate that there is between 1,000 and 1,500 trillion cubic feet (Tcf) of stranded gas resources worldwide. In some cases, gas is stranded because of physical distances and technical complexities associated with transportation. In many instances, however, gas is stranded because of a lack of sufficient demand in locations where the gas is produced. This condition is prevalent among developing and emerging market countries that are gas rich. Three main strategies are evident.

1. Build transportation infrastructure density for domestic markets or export opportunities (midstream). This first strategy rests on the abilities of host governments to facilitate investment in pipeline networks. It means having commercial frameworks in place that not only attract investors but also protect affected public interests. For regional natural gas trade to occur, contiguous countries must have commercial frameworks that are similar enough to encourage market participants to develop cross-border networks, deal with risks, and efficiently allocate gains from trade.

2. Convert gas to power, mainly for domestic use but in some cases for export. The global push to utilize relatively clean burning natural gas for power generation for both environmental and power generation diversification has triggered strong convergence between the natural gas and electric power value chains. Importantly, how commercial frameworks for electric power are structured can have profound implications for natural gas value chain development.

3. Export gas into the global marketplace through LNG, GTL, or other strategies. These strategies often link natural gas and electric power for oil pricing and contractual arrangements.

A set of natural gas system dynamics is emerging worldwide, leading to specific considerations for frameworks. Both exploration and production and power generation (although it is a downstream activity for natural gas businesses) are competitive activities that respond to vigorous private participation driven by rate of return (ROR) decisions formed on the bases of expectations about price. For exploration and production (E&P) operators with global positions, the desire to monetize stranded natural gas resources in the source country and region is critical. Pipeline networks or LNG for power generation developers, fuel competition is a distinct advantage in project economics. The midstream gas business of pipeline transportation and the transmission of electric power are dominated by regulation because of technical economies of scale associated with pipeline systems, as is local distribution of both natural gas and electric power.

Historically, these activities have been undertaken by monopolies, either as private, regulated companies (the U.S. and Canada, for instance) or as sovereign owned enterprises (most of the world before market experimentation). Within regulatory regimes, the goal from a business perspective is asset optimization via capacity utilization. Market-based rates or tariffs can instill flexible pricing in accordance with supply-demand balance. End users are most interested in, and desire of, competitive supply and pricing. The major trend today is therefore to push the benefits of competitive supply through to the value chain to customers and end buyers. A substantial level of investment is required worldwide to promote the use of natural gas as a cleaner burning fossil fuel, and to facilitate the expansion of expanded pipeline networks. The global energy investment outlook included estimates totaling nearly U.S.$13 trillion for new infrastructure development across the natural gas value chain worldwide. A number of issues will impact any investment outlook for natural gas and the convergence of natural gas with electric power.

One is the reduction in capital spending for E&P as the international oil industry continues to consolidate, large produce basins mature and governments change configuration commitments. As more E&P activity is subjected to global capital markets, investment will closely follow upstream returns. A second, more recent, phenomenon is the reduction in global capital flows as a result of the collapse of the U.S. energy merchant business model, in which the net financing new pipelines and power generation in many global locations with specific natural gas monetization strategies. In developed markets like the U.S. and Canada, the collapse of the energy merchants has also reduced liquidity in the natural gas marketplace (i.e., reduced the number of market participants, complicating risk management practices. Sovereign debt for infrastructure investment has been dramatically reduced over the years, a result of market and fiscal reforms (increasing the need for, and pressure on, infrastructure capital). Development of new infrastructure investment is also under pressure, as donor countries scrutinize more actively the results achieved thus far. All of these factors, and others, imply a number of complicated policy decisions that will provide incentives for private, foreign direct investment in their energy sectors.

### Investment Trends: IEA Outlook, 2001-2030, U.S.$ trillion

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<tr>
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The Link between Investment and Commercial Frameworks

Global Perspectives

Natural gas policy across nations is most easily differentiated by how the value chain is organized and operated with respect to the balance between market and government, that is, sovereign ownership of or control over the critical segments of the value chain. A strong pattern of government ownership, control or, in the least, intervention in natural gas enterprises and markets exists around the world as a result of several factors:

- The high degree of interdependency across the value chain segments;
- The propensity toward integration;
- The fact that, in most cases, large deposits of natural gas are associated with oil (a strategic commodity for many producing nations);
- The energy security aspects of natural gas supply and delivery; and
- The public interest/public service concepts embedded in pipeline infrastructure for both long distance transportation and especially local distribution.

In most countries, the natural gas value chain has been developed through regulated, sovereign owned or heavily controlled enterprises. The rare exceptions are the U.S., Canada and Australia, all of which allowed natural gas system infrastructure to emerge through the activities of private, investor owner companies. In the U.S. and Canada, this experience extends nearly 100 years; for Australia, since the 1960s. The U.S. is even more unique in that private ownership of much of the resource base is allowed — indeed, it is a powerful tradition. Federal and/or state ownership of the natural resource is limited to certain onshore lands and offshore, and even in these cases development of sovereign owned and regulated resources has always been through competitive acquisition of leases in organized auctions and private investment in exploration and production (a tradition also maintained in Canada, which has limited private ownership of natural gas resources in southern Alberta province where the vast majority of the natural gas resources are found). The U.S. system, however, is controlled by the provincial crown governments, and Australia where states and territories play a comparable role. Of great interest is the transition in many countries away from sovereign, foreign or national ownership and control of integrated natural gas enterprises, as well as the push for ever more competitive markets in many locations, including Canada and the U.S.

To a large extent, these transitions have been driven by specific needs — for increased efficiency and to introduce new technologies, to solve fundamental problems in pricing and service; to attract investment into the natural gas value chain. As with any industry, natural gas market development requires sufficient supply availability and enough demand to justify the infrastructure systems to connect buyers and sellers. To attract this investment, governments have experimented with policies designed to stabilize the investment environment by optimizing participant choice at predictable prices that reflect, or at least attempt to mimic, actual supply and demand conditions. During the past 15 years or so, the progression toward competitive markets has meant movement toward market determination of investment, and operation of assets subject to real time supply-demand interactions. Under these conditions, actionable information must be timely, accurate and transparent. For such information to be truly actionable, the decision maker also must have timely access to whatever system capacity the information prompts that decision maker (supplier, customer or intermediary) to demand. Finally, competitive markets may introduce systems that cannot be dominated or manipulated by a few anticompetitive participants. These conditions are difficult to create, implement and maintain, and imply new and changing roles for market participants and government overseers.

The range of experimental approaches for natural gas and electric power frameworks extends from privatization to commercialization, in which sovereign interests are not necessarily removed but rather some form of market incentives are provided to instill improved performance of state-owned enterprises, and from regulation to full deregulation and reduced role of government control (a phenomenon that does not yet exist). In many
early experiments, a natural inclination was to assume that the role of government would be diminished as private participation increased and competitive markets advanced. In contrast, the role of government often has increased – although this may be a transitory period as problems and complexities are addressed (with the U.S. a perfect case in point). At minimum, the role of government is altered, in complex ways. In most countries where competitive market experiments have advanced, governments must accomplish the following.

- Keep pace with fast moving, complicated market structures and operations.
- Ensure market transparency, especially the availability of good quality, unbiased data and information.
- Mitigate market power through new, information technology-driven processes and business organizations.
- Resolve disputes and conflicts, or provide requirements for dispute resolution mechanisms.
- Address public concerns about development of and access to energy resources and infrastructure, providing rules that protect consumers while at the same time protecting commercial rights of suppliers and facilitating investment.

The main driver for emerging gas/power frameworks continues to be the desire to substitute for (or displace) sovereign commitments for energy development. This means a transfer of development risk to private investors, with associated adequate rewards. A continuing challenge is balancing market liberalization with investment risk. A looming question around the world is whether, and how, to specifically price “reliability” which, for natural gas systems that include convergence with electric power, means deliverability of supplies and adequate pipeline transportation and distribution capacity, as well as sufficient gas-fired power generation capacity and associated electricity transmission and distribution networks. Natural gas storage, like electric power reserve margins, provides a reliability management solution. The bottom line for society is where reliability is highly valued is greater potential returns to risk-taking investors. Natural gas framework continues to be customer driven, and directed by opportunities for commercial arbitrage in ways that optimize regional trade patterns via comparative advantages.

From the investor point of view, the fundamental concepts continue to be: that investors differ according to their own risk profiles; that there is a direct risk-reward relationship; and that the cost of investment opportunities will vary in accordance with demand for those opportunities (that is, projects with the most appealing potential returns relative to risk will command premiums from investors). A number of critical questions are inherent in the evolution of natural gas frameworks. Foremost among these is whether regulators can also be market facilitators, and whether regulators are best placed to design markets. In both of these cases, conflicts of interest may arise because the regulator is also charged with maintaining market integrity. There seems to be no good answer to the question of how many regulatory jurisdictions might be required. Most countries continue to maintain regulatory entities only at the national level (the U.S. and Canada again being notable exceptions), but customer issues, like politics, are local in nature.

If no method of resolving disputes around local systems is provided, energy sector reform and development can either become gridlocked or disintegrate into local disputes. From both government and investor points of view, regional harmonization of regulatory practices in locations where regional trade in natural gas (and electric power) is vigorous, or could be so, offers both good and bad thoughts. In most cases, it may be worth opportunities to arbitrage across different regulatory regimes. Governments and their societies may prefer national as opposed to extra-national preferences, especially for energy security reasons. In any case, the World Trade Organization and nascent energy services negotiations are much more likely to be a “harmonizing force” following the disarray of the Cancun meeting in 2003. Finally, at the regional level, and even across jurisdictions in countries that are republics or federations, harmonization presents the specific problem of dealing with energy sectors in different stages of development or market transitions.

**Commercial Framework Principles for the Natural Gas Value Chain**

**Achieving Competitive Supply**

**Pricing Supply:**

- **Competitive Sales**
  - Wholestock producers
  - Third party wholesalers

**The challenges:**

- Entry of new suppliers
- Managing common pools
- Developing liquidity to establish market value
- Protecting market transparency
- Dealing with third party wholesalers that are affiliated with regulated infrastructure
- Access for new supplies
- Balancing short term cycles and long term capital requirements for resource development

**Regulated Infrastructure as the Conduit for Supply Competition**

**Pricing Transport, Distribution:**

- **RESERVATION (DEMAND)**
  - Fixed cost of investment
  - Return on equity
  - Long term debt
  - ASG, DA, O&M

**COMMODITY (USAGE)**

- Variable cost of operation
  - O&M

**The challenges:**

- Rate-regaining transitions
- Setting maximum allowable rates with market transparency
- Pricing new capacity
- Dealing with access for new capacity
- Determining contestable transportation markets

- Dealing with new power
- Balancing short term cycles and long term capital requirements for delivery

**The Overall Challenge: Balancing the Market**

**Mean reversion is a reality if market-clearing participants exist!**

**LOW Prices**

**HIGH Prices**

With respect to demand, energy sectors characterized by many customers as opposed to dominant or monopoly buyers reduce the instances of distortion, but complicate the process of transfer and reaction to price changes. This is especially true if the desire is to increase competitive access to natural gas and electric power supply for the smallest customers on local distribution systems. In general, retail customers can expect to pay a price that includes the wholesale cost of natural gas or electric power (including E&P and wellhead cost for gas, cost to generate electricity, and cost to aggregate and transport to the LDC system including wholesale marketing and any associated services); a retail cost (including the LDC system common costs, and price for a reasonable gross margin to suppliers). Various countries have experimented with competitive retail programs for gas and power, with mixed results. In the U.S., larger commercial and industrial users of natural gas have pursued unbundling options in order to lower prices and increase service. This shift results in the transfer of LDC system costs to smaller users, mainly core, residential customers. The process has been rational – large users routinely “subsidize” the more expensive, marginal costs for LDCs of serving smaller customers creating a market distortion – but it is, nonetheless, an artifact of market transitions that must be dealt with by policy-makers and regulators because of political repercussions. Rarely, in the U.S., do small customers have competitive choices for their suppliers, a failing of our natural gas regulatory regime.
A final consideration when it comes to natural gas system frameworks is the transfer of risk. As noted earlier, when natural gas value chains are either sovereign owned or controlled, or regulated private activities, consumers are shielded from price risk. With market liberalization, commodity price risk is created and must be dealt with. Likewise, capacity price risk is also created. In both cases, risk flows can be complex, moving back and forth across the value chain. The existence of risk accepting entities is essential in order to balance the marketplace and attract and sustain investment in both resource development and infrastructure. In summary, experience shows the world continues to the continuing challenges of balancing investor and government viewpoints on a number of fronts.

CHAPTER 5

ELECTRIC POWER VALUE CHAIN

A modern economy is dependent on reliable supply of electricity. There is strong correlation between the electrification and economic growth. On the other hand, typical electricity systems, consisting of central generation facilities, long distance transmission lines and distribution networks, are capital intensive. As a result of the importance of electricity for economic and social development and the scale economies involved in delivering electricity to consumers, a vertically integrated and monopolistic structure became the norm around the world from the early days of the industry. In most places, a government-owned monopoly generated, transmitted and distributed electricity. In the U.S., investor owned utilities performed these duties as monopolies within franchise territories but under government regulation. Regulators set the price that these utilities could charge their customers, allowing for cost recovery and a reasonable rate of return, and determined service quality and customer protection rules. Despite the difference between the ownership structure in the U.S. and the rest of the world, electricity had been treated as a public service almost everywhere, with the heavy involvement of the state.

Starting in the 1980s, however, the governments around the world started to restructure their electricity sectors, allowing competition in generation and sometimes in marketing of electric power. In most countries, restructuring required the dismantling of state monopolies into generation, transmission and distribution entities, privatization of all or some of these, and the creation of a regulatory agency to oversee these newly created marketplace and the players in it. Many of the states or territories in the U.S., Canada, and Australia, and many countries in Latin America, Europe and Asia have embarked on sector reform and are currently at various stages of new generation technologies (in particular, combined cycle gas turbines), inefficiencies in state and regulated utility investment programs, high electricity costs and lack of government funds to sustain system expansion needed for economic growth are among the most potent reasons for this restructuring trend (see the section on Electricity Restructuring below).

Despite more than 20 years of global experience with restructuring, electricity is not yet seen as a commodity by most people, including consumers, policymakers and industry professionals. In restructured markets, electricity prices have become much more volatile, with primarily fluctuations in demand throughout the day as well as across seasons. In the absence of financial tools and capacity to manage this price risk, most consumers as well as market players have had difficulty adjusting. In some cases, their electricity costs increased. Highly publicized market manipulation in California not only exposed the flaws in California’s market design (and hence underlined the difficulty of designing competitive electricity markets) but also shook confidence in restructuring. Blackouts and brownouts experienced in the U.S., New Zealand and Europe raised concerns about adequacy of investment in the transmission infrastructure in a competitive electricity industry. All of these developments underscored the fundamental difference between seeing electricity as a public service and treating it as a commodity with its own market dynamics.

However, the rising gap and the need for capacity expansion to fuel economic growth and the inability of governments to fund these expansions remains a strong driver in many countries for some form of restructuring that allows for private investment in the sector. Inefficiency of regulation, with its long history in the U.S., continue to give momentum to increasing the level of competition not only on the generation end but also on the retail end by providing customers with choice and responsibility to react to market prices. Competitive markets also seem to offer more opportunities for increasing energy efficiency and conservation, attracting investment into renewable or other alternative technologies, and expanding options such as distributed generation. To the extent customers are exposed to market price signals (i.e., limited or no price regulation in competitive segments of the industry), fluctuating according to the daily load curve, they have more incentives to modify their consumption patterns in order to minimize their costs.

For example, reduction of peak consumption levels by some customers (due to high peak prices) will help manage prices for all and maintain reliability of the grid. In competitive retail markets, electricity providers compete not only on the basis of price but also via offering a variety of products (e.g., contracts based on time-of-use pricing) and services (e.g., energy efficiency and conservation assistance). Some of the most successful retail products are renewable energy contracts; many customers are willing to pay a premium for electricity generated from renewable sources such as wind. Clearly, as customers’ responsiveness to price increases, not only the existing generation and transmission capacity will remain sufficient and reliable for longer but also negative emissions from the least efficient (hence most polluting) thermal plants.

In most places around the world, though, the immediate challenge remains increased access to electricity. There are more than one billion people in the world without access to electricity; and many more have
Electricity Industry Restructuring

Since the late 1980s, numerous jurisdictions have attempted significant electricity reform measures. In those nations where electricity assets have been publicly owned, privatization or corporatization has been a major element of reform. Many nations have also opened their doors to foreign investment in their electricity sector. This time, the industry restructuring efforts of the 1990s have their roots in developments in the U.S. The U.S. opened up its electricity market to independent (i.e., non-utility, non-regulated) generators with the passage of the Public Utilities Regulatory Policies Act of 1978 as part of an overall energy legislation, which also started the deregulation of the natural gas wellhead price controls (Natural Gas Policy Act). By the mid-1980s, natural gas production increased significantly and gas-fired generation based on increasingly efficient turbine technologies established natural gas as the fuel of choice for new generation, particularly for not long-burning (independent power producers, or IPPs) starting looking for opportunities around the world.

Key Drivers

The electricity crisis in California, though the most cited example of electricity market failure in the only country where natural gas has been associated with restructuring. Some form of market manipulation occurred in many markets especially during the transition period (e.g., the UK and Texas in their early years). Although regulators addressed most of these cases immediately and to the satisfaction of most market participants if not all, the vulnerability of the open market remains a major issue. The blackouts of summer 2003 in the U.S. and Europe led to concerns about reliability, many argued that restructuring was the main cause for these blackouts. Many are concerned that the level of investment in new generation and, in particular, transmission capacity will be inadequate in the coming years and that concerns about generation adequacy and grid reliability. Despite these problems and concerns, many regions continue to pursue restructuring of the electricity sector. Consequently, the fundamental drivers for change in the 1980s remain equally compelling today:

- Investment shortages, particularly in developing countries
- High electricity prices
- Technological developments, particularly those related to the growing efficiency of natural gas turbines

Investment Shortages.

In the developing world, a lack of access to capital has hindered investment in electricity infrastructure. Governments could not continue to support inefficient state utilities while budget deficits and debt increased. As a result, many countries have opened their electricity sectors to foreign investment. In the early 1990s, it was particularly true for countries that suffered most during the debt crisis of the 1980s, especially in Latin America. Moreover, during the 1980s, financial institutions, like commercial banks, invested in national energy projects and were severely lashed. In CONCAWE (the old European Commission) and many developing nations, which had a major impact on the developing world’s access to some world capital markets and may have driven developing countries to allow greater direct investment from abroad.

With more than one billion people without access to electricity and world economies growing fast, the governments’ need for private investment remains as relevant as it was in the 1980s. The IEA estimated the need for power sector investment in all countries at roughly $1 trillion, of which is expected to happen in OECD countries replacing old assets. Governments most in need of system expansion represent the poorest countries, and, as such, will have to be more proactive in their policies to secure the share of their remaining $6 trillion.

High Electricity Prices.

Electricity prices vary considerably across regions and countries, mostly depending on the fuel portfolio. For example, many countries in Latin America (Peru, Colombia and Brazil) and others around the world (Pacific Northwest of the U.S., Norway) rely on relatively cheap hydropower for almost all of their electricity needs. As a result, electricity prices have been relatively low as compared to other industrialized countries. But, if natural gas prices are higher, generators and retailers have less capacity. Retail prices will go higher in a market driven by natural gas spikes. The price spikes and shortages, partly caused by market manipulation, in 2000. But, restructuring process after the flawed model put in place by California suspended its restructuring legislation in 1996. California had been at the forefront of state electricity restructuring, privatization of its electricity sector beginning in 1989, was probably the inspiration for reforms in many places that followed the trend. In countries with federalist forms of government, state or provincial governments were on the way of deregulation. Outside the U.S., reforms in the state of Victoria predated national reforms. Similarly, in Canada, the province of Alberta was the first province to adopt electricity reform measures in 1996. The U.S., the State of California had been at the forefront of state-initiated electricity reforms, passing its restructuring legislation in 1996. California suspended its restructuring process after the flawed model put in place to price spikes and shortages, partly caused by market manipulation, in 2000. But, other states including those in the Northeast, many in the Midwest and Texas continue with mostly successful competitive structures, and the federal regulator (Federal Energy Regulatory Commission) has been trying to develop a standard market design based on regional transmission organizations.

Technological Developments.

Electricity generation has always been thought to exhibit economies of scale, which the requirement that the construction of larger plants. Developments in natural gas technology, however, have changed this belief. It is now possible to build smaller units that also increase efficiency. In recent years, new technologies, however, have changed this belief. It is now possible to build smaller units that also increase efficiency. In recent years, many high-cost electricity regions were among the earliest reformers.

For instance, in 1995 electricity prices in California were 43% higher than the U.S. average, and industrial electricity prices in Germany were 15% higher than in the Organization of Economic Cooperation and Development (OECD) as a whole. Not surprisingly, the consumers (in particular, large industrial and commercial consumers) in these regions were avid proponents of competition. The cost of electricity continues to be a key cost factor for most industries, perhaps even more now than before due to increased computerization of most processes. As such, industries will continue to push for restructuring that will lower their electricity prices.
supervise the activities of private players in this new marketplace, to protect consumers against market manipulation, to develop service quality standards, and to ensure the successful implementation of the competitive model. There are differences among the approaches used by different countries, but they all involved most of the following actions:

- Unbundling of generation, transmission, distribution, and marketing functions.
- Open access to the transmission and distribution grid.
- Creation of electricity trading arrangements (e.g., pools).
- Creation of independent system operators (ISOs).
- Creation of an independent regulatory agency (if one did not already exist).
- Privatization of electricity assets through sale or public auction, or the corporatization of the governance of the assets.
- Deregulation of electricity prices.
- Retail competition.

Each one of these actions deserves further discussion.

Creation of electricity trading arrangements (e.g., pools).

One of the most important design decisions relates to the wholesale market structure. Initially, a central pool, or exchange, model was popular. Although there are a number of variations to the basic pool functions as follows: generators submit bids on the amount of electricity they are willing to provide and the price at which they would be willing to provide this amount for different time blocks ahead (e.g., 24-hour bids). The next day, the pool operator dispatches bids from the lowest to highest price in real time until demand in any particular time block is met.

The price market for each time block is set as the price of the last dispatched unit. In many cases (most notably the UK and California) the pool was manipulated. Although they lack the same level of price transparency as pools, markets that depend mostly on bilateral transactions have been more problematic. The UK replaced its central system operator with a set of 15 bilateral systems; California pool is now defunct. Although bilateral transactions may account for majority of electricity trades, there will always be a need for a balancing market because the volatility of electricity load throughout the day as well as days and seasons. These “real-time” markets (day-ahead, hour-ahead) are usually run by system operators (see below) and bid-based pools. For example, in Texas, on average 90% of electricity is transacted based on bilateral contracts and the rest is traded in a balancing market where various ancillary services are exchanged.

Creation of independent system operators (ISOs).

As the transmission segment of the industry continues to manifest significant economies of scale, it is kept as a natural monopoly. In order to ensure fair and transparent access to the wires by all generators and consumers, an independent entity is created to have full authority over the control of the grid. These entities are usually created for profit. In some regions (such as the PJM market in the U.S.), the ISO is responsible both for reliable operation of the grid and settlement of commercial issues (e.g., running and settling balancing transactions because the volatility of electricity load throughout the day as well as days and seasons. These “real-time” markets (day-ahead, hour-ahead) are usually run by system operators (see below) and bid-based pools. In others (such as California), ISO and a power exchange tried to coexist but failed. There is growing trend towards the former structure, at least in the U.S.

Creation of an independent regulatory agency.

Since most countries had state monopolies, independent regulation was not necessary. But restructuring creates new, private entities and rules for a new, competitive market. A regulator is needed to license new players and new entrants, set and implement service quality standards, develop and administer customer protection rules, and monitor market behavior to prevent abuses or manipulation among other tasks. These are all important functions that help regulator fulfill its most crucial duty, which is to promote healthy development of the competitive marketplace.

The independence of the regulator from government as well as stakeholders is desired so that market participants can have confidence in fairness of the regulator. This requirement is even more critical when there are remaining state entities in generation or other segments of the industry after restructuring. However, establishment of these agencies, appointing their boards, staffing them with qualified people and proving their independence have not been easy. In many countries, they have been treated as just another government bureaucracy, which resulted in political appointment of the regulators. Finding qualified boards and staff had been difficult because there was no in-country experience with private investors or competitive electricity markets. Sometimes, regulators were chosen from the ranks of known opponents to restructuring. As such, in many places, the independence and competence of the regulatory agency remain questionable. Under these circumstances, the transition to competition has been more difficult and confrontational.

Privatization of electricity assets through sale or public auction, or the corporatization of the governance of the assets.

When state monopolies are unbundled, most generation assets are privatized (sometimes nuclear and hydro facilities are exempted), preferably to as many different players as possible so that healthy competition can blossom. After all, the purpose of restructuring is not to replace the state monopoly with private market power. Remaining state assets can be forced to compete with the private entities; but for them to succeed, they need to develop the appropriate corporation structure provided, of course, that an independent regulator is able to create a level playing field where neither private nor state entities are favored. Transmission and distribution assets can be sold but usually remain under state ownership; either way, the grid shall be run by an independent system operator to provide non-discriminatory open access. Privatization as part of the restructuring process yielded some of the expected results in many jurisdictions (see box nearby on the early experiences in Argentina, Chile and Peru).

Deregulation of electricity prices.

Competition requires electricity prices to be determined in a market environment either through bilateral contracts or spot pools. Prices set below cost or differently to various consumer groups for political reasons will deter investment. If governments offer higher-priced power purchase agreements (PPAs) to attract investors but continue to subsidize consumer rates, they will not be able to relieve their budgets of the burden of the electricity sector. In more open and liquid markets, competition will increase volatility of the electricity price; regulators usually employ price caps to limit the magnitude of price spikes. If set too low or interfered with often, these price caps will also discourage investment. Given the history of electricity as a “public service,”

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**Unbundling of generation, transmission, distribution, and marketing functions.**

The traditional vertically integrated structure is broken up and generation is separated from the wires (transmission and distribution, or T&D); mainly because potential for competition has been readily visible in generation due to advances in efficient gas turbine technologies as discussed before. Divestiture of generation assets, where administered, helps establish competition faster. Separation of local distribution networks from privatization and, if desired, retail competition (marketing) in each region may also help by creating a large number of customers who are looking for the “best deal”; this is especially the case for largest consumers such as industrial facilities.

**Open access to the transmission and distribution grid.**

The transmission grid remains as a regulated natural monopoly because transmission expansion remains a capital-intensive activity and system reliability requires central control of grid operations. Similarly, local distribution networks will remain regulated. As such, for competition in generation and marketing to yield benefits, companies active in these sectors need to have fair and non-discriminatory access to the wires. This is especially important if the separation between generation activities of an ex-utility and its transmission operations is not well established.
deregulation of electricity prices remains one of the most difficult challenges for governments undertaking sector reform. It is simply too high of a risk for many politicians to even consider taking; some politicians in developing countries may go as far as offering free electricity to win elections. Unfortunately, under these circumstances, investment in new generation will not come. A survey by the World Bank confirms strongly that the availability of retail prices to allow cost recovery is a key concern for power plant developers.

Retail competition. Retail competition is needed to incorporate demand side of the market. In most places, industrial and large commercial users have been able to shop for their electricity suppliers as they have the incentive to do so in the form of large savings. But, smaller users have not been too interested in comparison shopping even in Texas where the market has been open for all customers from January 1, 2002) and both regulators and companies have been actively marketing retail choice. In Texas and elsewhere where retail competition is available to all customer classes there is an unfortunate paradox at work. Small customers do not have strong incentives to switch because they save savings are limited. Unfortunately, since there are millions of them, their impact on the system is large and can be critical during peak hours, pushing prices high for everyone and occasionally jeopardizing reliability. As such, the realization of demand side response by all types of customers is becoming a cornerstone of restructuring efforts in most advanced markets. Naturally, in regions where electrification of the market remains a priority, retail competition will not be an immediate concern.

Electric Power Value Chain Components

Electricity is not only essential for economic development but also for improving the quality of life. The value chain of the electric power industry can be divided into several components, including generation, transmission, distribution, and retail. Each of these components plays a crucial role in ensuring a reliable and efficient electric power supply.

Key Segments and Activities

While there are numerous jurisdictions that restricted their electric power sectors, there are many that maintain the traditional vertically integrated utility structure (independent utilities in the U.S. and state-owned monopolies in most other places). The following chart depicts this utility structure with its captive customers and the restructured marketplace that allows for competition in generation by merchant companies as well as self-generators and in marketing. Note that transmission and distribution segments remain regulated monopolies as discussed before.

Production of electric power using a variety of technologies and fuels. Thermal power is generated from the burning of fossil fuels (oil, natural gas and coal) in steam or combustion turbines. Nuclear power is generated from the fission of uranium. Hydropower is generated using motive power of water in turbines. Windmills convert the motive power of the wind into power and solar technologies convert heat content of solar rays into electricity.

Transmission

A system of high voltage (usually greater than 69 kilovolt) lines, substations, and control systems that allows for transportation of electricity over long distances from generation plants to load centers. Traditionally, copper is used to manufacture transmission lines; but new materials are researched to reduce losses during transmission and the need for maintenance. In restructured markets, transmission operations are managed by a system operator, which is usually independent from other stakeholders and not for profit.

Storage

Electricity cannot be easily stored. Energy is usually stored in the fuel itself before it is converted to electricity. Compressed air, flywheels, thermal storage, hydroelectric, advanced batteries and superconducting magnetic energy storage are the four main technologies being studied for possible electricity storage. If economic storage technologies can be deployed, the electric power industry and markets will change significantly. Price volatility will likely decline, system reliability should be enhanced, and intermittent technologies such as wind and solar will attract more interest.

Distribution

Retail sales and final delivery of electric power via low voltage local networks (poles and wires commonly seen in neighborhoods) operated by local distribution companies or LDCs (regulated utilities). Substations on the transmission system receive power at higher voltages and lower them to 24,900 volts or less to feed the local networks. At key locations, voltage is again lowered by transformers to meet customer needs.

End use

Direct use of electric power by residential, commercial and industrial consumers.

The following commercial elements serve to operate the segments of the electric power infrastructure system and link suppliers, transporters and distributors with their customers.

1. Aggregation: Consolidation of small consumers in order to increase the negotiation power in competitive retail markets.

2. Marketing: Purchase of electric power from multiple suppliers and resale to wholesale and retail markets. Retail market includes sales to final end users (typically residential, commercial, industrial, and public sector).

3. Information services: Creation, collection, processing, management and distribution of data related to all the other industry functions listed here.


5. Risk management: Balancing of supply, demand and price risks.

Key Policy and Regulatory Considerations

Altogether, the elements described above constitute the electric power value chain. The various segments are highly interdependent but, in an open competitive market, they also can be highly competitive as well. The problems that arise are the challenges associated with introducing competition or increased access to electricity are numerous. The first hurdle is the creation of frameworks for efficient and sustainable market design. New regulatory agencies and new regulations are needed. Newly established regulatory agencies have difficulty finding qualified personnel, developing regulations consistent with the requirement for independent and efficient establishing authority. Even experienced regulators have to learn new skills and develop new functions, such as market monitoring, to continue to serve consumers while ensuring the success of the new competitive market. Designing markets for competition is the second hurdle. There have been numerous cases of market players taking advantage of flaws in market design; some of these flaws cannot be perfectly corrected according to the rules of the new market. Nevertheless, they raise the price. Even if the price increase is limited and temporary, it can hurt the market development because of reaction from media, consumers and policy makers. In particular, there are two related design issues: 1-operation of the physical grid, and 2-structure for electricity trade, i.e., financial transactions. Many in the industry have been concerned about maintaining grid reliability in a competitive marketplace. After all, increasing generation capacity cannot be sufficient to increase access to electricity if transmission grid cannot be maintained and expanded in a timely fashion. Transmission investment remains regulated and, in general, less attractive for investors than generation. Moreover, the management structure of the grid offers a variety of challenges to reliability.

Significant blackouts experienced around the world in 2003 seem to have supported these concerns. The blackout in the U.S. northeast on August 14, 2003 was historically significant and resulted in losses of at least 40 billion dollars. One of the main culprits for this blackout was a utility that failed to maintain its grid and communicate the problems it started to experience to neighboring control areas (i.e., utilities) early enough to avoid the cascade effect. For many, these blackouts were a result of restructuring; for others, it only proved that a regional ISO, instead of individual utilities, would have done a better job managing the grid and avoiding the problem.

In short, the market design remains the fundamental point of conflict amongst those involved in market restructuring. The competitive models across the world share certain common characteristics such as unbundling of vertical integration and open access to wires, but vary (sometimes significantly) in other respects such as wholesale market structure and trading rules, capacity payment schemes, and transmission system management. A poorly designed market will lead to problems, which will shake the confidence of stakeholders in the market and hence render the transition period longer and more complicated. In particular, a market design that does not treat reliability as its central concern would seem to be destructive to development from both economic and political perspectives. The following graph depicts the central role of reliability in designing competitive electricity markets and a set of related issues. Every one of these issues can have a negative impact on reliability, and hence shake confidence in the market, if not structured properly.

Most of these issues were discussed before in the Electricity Industry Restructuring section. Some are worth a closer look. Although a small merchant transmission business is emerging (at least in the U.S.), building new transmission lines and maintaining the existing infrastructure continues to remain a challenge for all utilities. In most places, the state monopolies in most of the world. Even if merchant business proves to be viable, siting, licensing and constructing new facilities will continue to be a
long and costly process in most of the developed countries as public's resistance to major infrastructure investment near where they live continues to be a growing problem. Under regulation, returns on these investments seem to be too low to keep investors going with the siting problems or to raise capital. For example, one of the solutions discussed after the August 14 blackout in the U.S. was to increase allowed rate of return on transmission investment.

Unless mitigated by regulatory and political means, these problems may jeopardize timely investment in the T&D infrastructure, impair efficiency and reliability. For most of the world, however, the primary obstacle still is the capital requirement for these projects. Investment adequacy remains an issue on the generation side as well. Many countries and entities are using power purchase agreements (PPAs) to attract independent power providers (IPPs). In most cases, PPAs turned out to be higher priced than either domestic generation costs, or expected revenues from both. IPPs required these higher rates (especially in early years of their operation) to show lenders cash flows sufficient to recover their investment in otherwise non-competitive regions where there are market risks in the form of subsidized pricing policies, high rates of system loss due to theft and strong presence of state entities. But, in many places, electricity generated could not be dispatched because there was public outcry about higher rates or state could not afford to buy it or generation by state entities were favored or other similar reasons. As a result, local authorities tried to renegotiate or cancel the PPAs despite arbitration clauses the contracts had (e.g., in Turkey, India, and Indonesia among others). Naturally, these plants could not contribute to generation adequacy in these countries.

In more open markets, authorities have employed capacity requirements (target reserve margins) administered by system operators and/or regulatory agencies as well as capacity payments (or markets) to encourage investment in sufficient generation capacity. But, evidence of capacity schemes have been mixed so far; they mostly failed to provide the right price signals (sometimes due to political interference to design them for favoring certain types of fuels – see box nearby for a case on Peru) and the capacity markets have been subject to gaming. Capacity requirements, on the other hand, are most consistent with the old integrated resource planning approach, but some of the old problems arise. For example, what is the right capacity margin? The balance may be comfortable with around 20% or more in 1990; but it is now satisfied with as low as 12% in some regions. The reserve margin depends on generation stock, fuel prices, load shapes, demand elasticities of different customer groups, all of which are difficult to estimate and may change over time. Another issue is the cost of keeping excess capacity and its allocation among the market participants.

These are some of the most pertinent issues in electricity markets; some are relevant regardless of the level of openness in the market, others issues faced by developing countries. The complexity of issues multiplies as markets transition from regulated monopolies to competition. The promise of competition in electricity depends on successful resolution of the problems to the satisfaction of a great majority of the stakeholders across the electric power value chain. Investment in the Electric Power Value Chain is the key ingredient for economic growth. But currently, there are more than one billion people around the world without access to electricity. Capital electricity consumption in the world is somewhere between 2,500 and 3,000 kWh as compared to 13,000 kWh in the U.S. and 6,000 to 8,000 kWh in OECD countries. Clearly, OECD countries are pulling the average highest; most of the world does not consume anywhere near 2,500 kWh per person. For example, in Bangladesh only 20% of a population of roughly 140 million people has access to electricity with an average per capita consumption of just over 100 kWh. In Africa (excluding South Africa), the average consumption for roughly 767 million people is about 300 kWh per person. Even after over a decade of rapid economic growth, an average Chinese citizen consumes only about 1,500 kWh. An average Indian consumes only half as much as a Chinese citizen.

Clearly, there is a need for large capital investment to expand the reach of electricity to a greater proportion of the world population. In the recent World Energy Investment Outlook, the International Energy Agency (IEA) estimated that more than $4 trillion for new generation capacity, $1.6 trillion for new transmission lines, and $1 trillion for new distribution networks would be needed globally between 2001 and 2030. This amount is needed to meet expected demand increase of 2.4% per year, faster than any increase seen in the past. The demand growth is strongest in developing countries (4% per year) and among resident users, this level of investment will not be sufficient to bring electricity to everyone. Part of the investment is in power generation and infrastructure, mostly in OECD countries. Only about $2 billion will be invested in building new generation in developing world. Almost 66% of installed capacity in 2030 will have been built after 2000.

Natural gas has been the fuel of choice for power generation around the world. In resource-rich countries, gas-fired power plants provide an opportunity to monetize stranded gas resources by creating local demand. In most places, low cost of construction, higher efficiency and lower emissions of gas plants increase their popularity. The liquefied natural gas (LNG) industry that has been cutting costs now makes natural gas available to an increasing number of consumers around the world. Accordingly, more than 40% new generation capacity in the world is expected to be gas-fired. Almost half of this increase will happen in OECD countries. There are significant uncertainties in most other countries regarding the ability of attracting capital needed for infrastructure investments such as upstream development, pipelines, and terminals and natural gas power facilities. Over the past decade, it has been very difficult for countries to finance infrastructure projects through sovereign debt or development assistance, especially bilateral and multilateral. These factors weighed significantly against the results achieved in the past. Project financing has been playing an important role but capital lenders are even more scrupulous than donor countries and past problems with PPAs and distribution utility privatizations made lenders even more cautious (see the Project Finance chapter for additional discussion).

The Link between Investment and Commercial Frameworks

Global Perspectives:

In most countries, the electric power value chain has been developed through integrated, state owned enterprises. Even in the U.S., privately owned utilities have been kept vertically integrated and regulated. Several factors supported this vertically integrated organization:

- The high degree of interdependency across the value chain segments;
- The propensity toward integration;
- The energy security aspects of electricity supply and delivery; and
- The public interest/public service concepts embedded in infrastructure for both long distance transmission and especially local distribution.

Since the 1980s, however, numerous jurisdictions have attempted significant electricity reform. In those nations where electricity assets have been publicly owned, privatization and/or corporatization have been a major element of reform. Many nations have also opened their doors to foreign investment in the electric power industry for the first time. As a result, about $200 billion will have been invested by the private sector in developing countries, mostly in East Asia and Latin America, between 1990 and 2001.

In East Asia, almost 70% of roughly $95 billion invested has been in green field projects while in Latin America, almost 75% of approximately $50 billion has been invested in privatized state assets. Unfortunately, after 1997, private investment in developing country power sectors fell significantly from $45-50 billion in 1997 to less than $6 billion in 2002. Over the same period, the number of transactions also declined from about 125 to about 39. The financial crises in Asia, Argentina, and Turkey that led to currency devaluations and macroeconomic instability rendered these investments riskier. Exposure of some investors to these riskier countries as well as problems experienced by some companies involved in their own home markets (e.g., some U.S. companies suffered significantly following the California crisis and the collapse of the energy trading business) reduced the ability to finance new projects or in the case of existing capacity. Moreover, many companies overpaid based on optimistic estimates of potential return or changes in markets.

Commercial frameworks for electricity offered by many countries left much to be desired and many companies had bad experiences in certain markets. According to the World Commission on the Regulation of Electricity, the ability to collect payments, appropriateness of retail tariff levels, operational and management freedom, and the presence of a legal environment are important factors supporting this vertically integrated organization: 

- Power Value Chain Electricity is the key ingredient for economic growth.
- Investment in Electric Power Value Chain is the key ingredient for economic growth.
- The Right Price Signals: Sometimes due to political influence, designed by the electricity value chain.
- Power Purchase Agreements (PPAs) to attract independent power providers (IPPs).
- Capacity Margins: Consistent with the old integrated resource planning approach.
- Policy Frameworks: High degree of interdependency across the value chain segments.
- Propensity toward integration.
- Public Interest/Public Service Concepts.
capital between 1997 and 2000 while financing in Asia and Latin America declined. In 2003, project financing in the power sector accounted for $40 billion with 133 projects [a 66% increase from 2002]; but the largest four countries are the United States, the United Arab Emirates, Indonesia, and Malaysia.14 Except possibly for Indonesia, these are not the countries most in need of investment. The Indonesia case involves a restructuring of the power sector which was originally financed prior to the 1997 financial crisis but became entangled in disputes after the crisis.

Overall, capital seems to be available, but there is competition among countries and sectors. Developing countries will have to address the problems experienced by power sector investors in the 1990s by creating attractive commercial frameworks to re-direct the flow of international capital into their power sectors. Companies need to be more diligent about their market and risk evaluations and realistic about their expectations. Finally, both governments and companies need a long-term focus.

The World Bank survey provides a fairly comprehensive list of commercial framework issues that need the attention of governments. The survey was sent to 67 companies. Among the 48 companies that responded, 83% are from North America and Western Europe. 26 of them invest only in generation facilities. More than half are subsidiaries of utilities (i.e., merchant arms of the utilities). Most respondents are relatively small in terms of capitalization. 21 of them seek returns higher than 16% with another 17 looking for returns in the range of 12-16%. These high return expectations indicate the perception of high risk in developing countries. Half of the companies are less interested in developing country power sectors given their own experiences but the other half remains interested reflecting not only differences across countries and commercial frameworks but also differences among company priorities.

The most desired characteristics in a market according to the responding companies were: the existence of a legal framework defining their rights and obligations as foreign investors; the presence of a regulatory framework and the enforcement and availability of a guarantee from the government or a multilateral agency. Presumably, guarantees can be lower in a country where rules and regulations are transparent and consistent and cash flows are adequate and predictable. The adequacy of cash flows requires not only the ability to collect payments but also the appropriateness of electricity prices for different customer groups. Most of the companies responded that respect for financial agreements and rule of law was the most satisfying experience, while they can show lenders the adequacy of their cash flows as well as their ability to manage other risks that may exist in a given country.

The companies responding also desire a more responsive and administratively efficient government. Investment timeframes for most countries are governed by tight budgetary deadlines and market pressures. Processing delays caused by capriciousness or the lack of preparation on the part of the government agencies increase the cost of doing business for investors. Once the investment is made, respondents performed the best and were most satisfied with their experience in countries where the governments did not interfere with operation and management of their assets. In this respect, investors value highly the independence of regulation from political forces. The following table provides a ranking of issues considered by the investors when evaluating a developing country. In addition to the four “deal- breaker” priorities discussed above, the list of major issues to evaluate before an investment decision can be made.

<table>
<thead>
<tr>
<th>Priorities when investing in a developing country</th>
<th>Min</th>
<th>Max</th>
<th>Low</th>
<th>Medium</th>
<th>High</th>
<th>Deal Breaker</th>
</tr>
</thead>
<tbody>
<tr>
<td>Legal framework defining the rights and obligations of private investors</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Consumer protection and disclosure standards</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Availability of credit guarantees or guarantee from government and multilateral agency</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Independence of regulatory and administrative processes from government intervention</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Administrative efficiency – time to get necessary approvals and licenses</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Judicial independence – degree of perceived independence from government influence</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Transparency of rules and practice, rule of law</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Regulations that clearly define and ensure access to infrastructure</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Investment grade credit rating for long-term foreign exchange debt</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Negative perceptions of labor or business environment, inability to attract foreign investment</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Labor markets or administrative processes</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Tax regime or taxation system</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Debt and available facilities to finance domestic borrowing</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Reliance on a competitive process for sale of project ownership</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Ability to vertically integrate with other segments of the energy chain</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
<tr>
<td>Perceptions or disputes over disputes, contract violation, property seizures</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
<td>X</td>
</tr>
</tbody>
</table>

Source: Figure 3.1 What International Investors Look for When Investing in Developing Countries

When respondents were satisfied with their investments, they attributed their satisfaction to several factors which reflect adequate treatment of most of the issues listed above. In the order of importance, the positive attributes that make an investment successful include the following:

1. Adequacy of retail prices and collection discipline to meet cash flow needs.
2. Ability to exercise effective operational and management control of the project.
3. Government meeting all commitments of state-enterprise performance and internal tax conventions.
4. Enforcement of laws and contracts (e.g., disconnections, payment by counter-parties, etc.).
5. Availability of timely recourse financing.
6. No over supply or capacity utilization problems (demand growth as projected).
7. No oversupply or capacity utilization problems (demand growth as projected, regulatory commitment could not be sustained).
8. No oversupply or capacity utilization problems (demand growth as projected, regulatory commitment could not be sustained).
9. Adequacy of retail prices and collection discipline to meet cash flow needs.

Note that except possibly for numbers 5 and 7, all of these factors represent elements of the commercial framework that the governments need to put in place to bring back investors to their countries. Respondents had their worst project experiences when these elements were not present, ranking the most important problems as follows:

- Government was unresponsive.
- Retail prices were too low.
- Collection discipline was absent.
- Regulatory commitment could not be sustained.
- Disputes and tariff adjustments were arbitrary.
- Laws and contracts were not enforced consistently.
- Government did not meet its commitments of state-enterprise performance and exchange conversion.

The survey results indicate that investors have been able to find adequate conditions all around the world but more consistently in smaller countries such as Bolivia, Costa Rica, the Dominican Republic, El Salvador, Guatemala, Jamaica, Mexico, Nicaragua, Panama, Peru, and two small and open economies.9. However, the other hand, 9 out of 10 companies that invested in Argentina were very dissatisfied with their experience. Similarly, five out of six in Colombia, 10 out of 11 in Brazil, 11 out of 12 in Peru, and two out of 2 in China were very dissatisfied. Accordingly, India, Pakistan, Argentina and Colombia did not fair well among investors as future investment prospects.

Another World Bank study1 provides more or less the same conclusions, focusing on 10 East European and Former Soviet Union countries – a group not covered in the Deloitte survey summarized above. According to this study’s results, the timing of restructuring or privatization efforts is crucial. It is usually counterproductive and damaging in the long run if structural changes are attempted during times of economic contraction or political crisis or instability (however mild it may be perceived from outside). Assuming that the country is generally stable, governments need to be the foundation for private investment to be able to sustain restructuring and competition. In particular, governments need to put in place laws and regulations that enable companies to deny service to those who do not pay, to recover unpaid bills quickly, and that define electricity theft as a criminal offence punishable by fines and jail terms. In addition, governments should set retail prices to allow cost recovery and should reduce (eliminate, if possible) internal cross subsidization. The correction of price distortions and future setting of cost-reflective prices can probably only be achieved by independent regulatory bodies but they must have adequate financial and personnel resources. A professional regulator will most likely divide the costs among all private partners that need to be created. One of the challenges, though, is the ineffectiveness of regulatory agencies that makes political pressure more difficult to handle. It may be difficult for regulators to provide the right pricing and collection discipline in early years especially if governments fail to resist the temptation to interfere with the regulator and set tariffs based on arbitrary adjudication of tariff adjustments.

Similar to the survey results, appropriateness of electricity prices and collection discipline are crucial ingredients of the commercial frameworks that need to be created. One of the challenges, though, is the ineffectiveness of regulatory agencies that makes political pressure more difficult to handle. It may be difficult for regulators to provide the right pricing and collection discipline in early years especially if governments fail to resist the temptation to interfere with the regulator and set tariffs based on arbitrary adjudication of tariff adjustments. As in other studies, this study notes that regulatory agencies must be free of political influence and their processes must encourage competition, be open and transparent. Perhaps most importantly, the regulatory agency and its roles and responsibilities should be designed and put in place before restructuring is undertaken. This study also acknowledges the absolute necessity of cost-reflective prices as an incentive to investors, but also points out the importance of maintaining a balance between the need for new investment in new capacity and the socially desirable policies that provide safety nets and increased access to electricity.

The graphic below is the summary of a Deloitte Emerging Markets Group study. According to the study, key success factors are:

- Political leadership to drive through sector reforms and project agreements.
Sensible and Sustained Policies

Overall, this study confirms most of the findings from the World Bank studies discussed earlier; but it also clarifies the importance of political leadership and support for successful reforms. In addition, however, it brings to attention the substantial role domestic private capital can play in financing electricity infrastructure investments, provided that domestic financial infrastructure is sufficiently sophisticated.

Commercial Framework Principles for the Electric Power Value Chain

Like with the natural gas industry, unbundling of the vertically integrated structure has been one of central principles of electricity industry restructuring. Once unbundled, generation segment proved itself to be fairly competitive as suspected. Merchant companies, growing in numbers and experience since the early 1980s, were mostly up to the task of building generation facilities around the globe. For these generators to compete, they needed to have fair and non-discriminatory access to the wires (i.e., transmission and distribution systems), which are kept as natural monopolies. This right to access is known as open, or third party, access – another central principle of restructuring. As already discussed, though, expansion of these systems remains a problem under regulated prices. For example, many utilities in the U.S. have expressed a desire to see higher allowed rate of returns before they could justify the risks involved with T&D investments.

Relevant Case Studies:
- Brazil Power Market Crisis
- Electricity Restructuring in California
- Gas and Power in Peru
- Power Marketization in Turkey
- Results of Electricity Restructuring in Argentina
- Results of Electricity Restructuring in Chile
- Results of Electricity Restructuring in Peru

Achieving Competitive Demand

On the retail side, large customers (industrial and commercial) seem to have benefited from having the choice of electricity suppliers, including the option of self-generation. In most regions, large users have been major proponents of competitive generation and have had choice from the beginning. On the other hand, smaller customers (residential and small businesses) have been more reluctant to embrace retail choice where available. Most successful examples include Texas and the UK markets where residential switching rates are about 20% and 40%, respectively. Some of these switchers are back to incumbents. There are several problems with marketing to small customers. It costs more to market to small users on a per kWh basis. It is difficult to differentiate from other providers; except for some “green” electricity products, customers do not seem to care what “color” their electrons are. As long as the price is the dominant marketing feature, it is difficult to show large enough savings to overcome the inertia of most users.

Regulated Infrastructure as the Conduit for Supply Competition

However, if all consumers are subjected to real time prices that are more reflective of cost fluctuations throughout the day as well as across seasons, it may be possible to see a larger demand side response even from smaller users. This could not only provide marketers to develop new services and products but also help maintain system reliability during peak hours. Yet, subjecting residential consumers to price volatility is a politically difficult proposition. In most of the world, though, the immediate challenge remains the development of generation capacity and T&D infrastructure in order to increase the number of people with access to electricity. This challenge requires the creation of the right commercial framework by governments to attract and keep investors, and encourage competition and consumer choice. Gradual removal of subsidies, reduction of system losses (technical and theft-related), and respect for contracts are among the improvements that are needed as part of the commercial framework conducive to investors.

Another issue concerns the allocation of fixed costs associated with the T&D infrastructure. In many regions, system maintenance and upgrade costs as well as congestion management costs are distributed across all customers, known as “socialization.” Since reliability is valued by almost everyone, this practice may sound reasonable. But there are instances where many criticized the “socialization” of these costs. For example, in Texas wind farms were built far away from the load centers although they knew that the transmission capacity between their location and load centers was insufficient. A new transmission line is being built primarily to make that wind capacity available but the cost of the line will be paid by all consumers. Many find this unfair. Similarly, congestion costs can be included in T&D costs and paid by all consumers. In nodal markets, however, it is possible to identify and bill those who cause the congestion, which sounds fairer. These are just some of the issues associated with managing electricity grids in a competitive environment.

Muhammad Firman (University of Indonesia - Accounting)
Governments, Economic Organization and Energy

Energy is essential for economic development. As a consequence, nation states and their societies have often taken a direct hand in the development of and access to energy products and services. At this time in human history, however, there is considerable debate about the proper role for governments in their energy sectors, just as there is debate about government intervention in national economies overall. A wide array of models for energy sector organization currently exists in existence around the world, but there is also a marked trend toward reducing government intervention and increasing “market-based solutions” for energy development, transportation and distribution. By market-based solutions we mean the reliance on the objective interactions between buyers and sellers, with price discovery and transparency and minimal interference, to exchange energy goods and services.

The extent to which energy is perceived to be a strategic material as opposed to a commodity is often the major factor dictating the extent of government involvement in a nation’s energy sector. The idea that energy fuels are commodities like any other (non-fuel metals or agricultural products, for example) is relatively new and emerged out of the disruptions in world energy markets during the 1970s and 1980s. Extreme fluctuations in the prices of energy fuels and changing world market conditions for energy, with growing fuel competition as well as the shift toward market-based economic reforms overall, led to the increased perception that energy fuels could be managed like commodities. The emergence of spot and futures markets for energy fuels, as described in Chapter 1, provided both energy customers and suppliers with instruments for the management of price and supply risk. As suppliers and customers become more comfortable with the notion of energy fuels as commodities, there is less of a need for government intervention as method of managing these risks. This level of comfort and the linkage to government policy is often related to other factors, as shown in the chart at left. Size of resource base, the financial balance sheet of the country, level of institutional development are some of the prominent factors that can drive government policy toward or away from energy sector restructure. Finally, the extent of government involvement tends to be directly linked to how national economies are organized. These simple relationships can be generalized as shown in the table that follows.

| Economic and Government Organization of Energy Sectors: Possible Solutions |
|----------------|----------------|------------------|
| Economic and Government Organization of Energy Sectors: Possible Solutions |

The table above suggests that in countries that tend toward centrally-planned economies and where energy is considered to be a strategic material, government-based solutions for energy are more frequently observed (solution A). Good examples are Mexico and the People's Republic of China. In countries that tend toward market-based economies and where energy is generally regarded to be a commodity like any other, market-based solutions are more frequently observed (solution D). Examples of this situation at this time are the U.S. (strong) and Canada (less strong), which have been moving in this direction for some time. The interesting exceptions are solutions B and C. No good examples of solution B exist for a nation as a whole, because the perception of energy fuels as commodities are most compatible with existence of market-based economies. However, the hypothetical solution B does provide an interesting explanation for some aspects of energy sector management in countries like the U.S. and Canada. Both retain strong government intervention when it comes to energy fuels for military defense purposes in spite of the treatment of energy fuels as commodities and the shift toward market-based solutions for energy when it comes to private transactions. Solution C is the most dynamic situation and is in evidence in many parts of the world.

The U.S. and, to some extent, Canada displayed many characteristics that might be associated with solution C during the latter half of this century. In countries that are moving toward market-based economies, market-based solutions for energy are more prevalent. These countries are moving toward solution C from solution A. Parts of Western Europe and India are good illustrations of this trend. As the idea grows that energy fuels are commodities for which security and price risk can be managed, these countries will be able to move more strongly toward market-based solutions for energy (toward solution D from solution C).

➢ Countries are making positive shifts away from the institutional arrangement of state-owned or regulated monopoly toward competition to take advantage of a mature infrastructure.

➢ The fundamental philosophical question is how to provide for infrastructure development while also facilitating competition.

Marketization can achieve a great deal. Although not energy industry specific, the following chart 19 is informative of the negative correlation that exists between regulation and economic growth. In particular, the growth in Ireland and Britain was twice as high as the growth in Greece. The authors compared the 11 EU economies in terms of market regulation and output growth and ranked them. Under market regulation, they considered both product and labor markets. For the labor market, they included information on the regulation of normal work time, flexibility of irregular work time, temporary employment, dismissal protection and minimum wages. For product markets, they constructed an indicator incorporating information on business regulation, competition policy, public ownership, sectoral and firm specific support to manufacturing companies, regulation of shop opening hours, and the implementation at the national level of the European Single Market program. This simple correlation ignores other variables such as initial human capital, initial real per capita GDP, share of government consumption in GDP, and measures of political stability, which could also impact growth. As the authors claim, however, these are not likely to be significant given the common past of the EU members.
the premise of breaking out of this negative correlation and spur development by increased private investment. But, regulation has its appeal, especially in network industries such as energy industry. The U.S. accomplished a great deal with regulated private franchise monopolies of natural gas and electric power industries. The following chart shows the growth in the U.S. natural gas market. While competitive producers have been able to increase production, albeit under price controls after 1954, regulated utilities expanded the transmission and distribution grids to connect those supplies to consumers. But inconsistencies among wholesale price controls, transmission tariffs and regional markets eventually constrained production. In reaction, the industry was deregulated starting in 1978.

### The Goals of Governments

Clearly, governments may have many different goals when it comes to energy, depending upon the mix of macroeconomic organization, perceptions about energy fuels and the resulting approaches. Where government-based solutions for energy are in evidence, countries may exhibit such goals as securing energy supplies for their citizenry (if they are large net consumers) or increasing revenues from energy exports (if they are energy net producers). Many governments also have goals to improve the efficiency of their policies or to introduce some aspects of market-based solutions. State-owned enterprises (SOEs), which produce and provide energy products and services in many countries are often considered to be inefficient and a political medium for lowering unemployment. As a result, many governments have sought solutions to improve the performance of their SOEs or, in several instances, have chosen to privatize their SOEs in order to instill the performance incentives associated with competition. For countries where market-based solutions are prevalent, many governments may have goals to “protect” the market from anticompetitive practices, to improve transparency, or to minimize the impact of government policies like taxation.

When it comes to introducing or expanding market-based solutions, governments have many different solutions. Since deregulation and corporate viability have become more critical than ever before for most countries. To cope with these new realities, the U.S., Canada and Western Europe have significantly relaxed government control of several industries, including many sectors of the energy industry. A similar, albeit relatively partial movement towards freer and more open markets is underway in Latin America and Central and Eastern Europe (CEE) as well as the Asia/Pacific region. Governments have opted to restructure their national energy sectors in order to create more competitive markets, especially in industries, like energy utilities, that traditionally have been treated as natural monopolies. However, restructuring can take many forms. Where state ownership has been prevalent, privatization and commercialization are the common approaches. Where private ownership has been prevalent but with government control, deregulation, “re-regulation” or liberalization are typical strategies. All of these concepts involve price, entry, exit and vertical or horizontal business integration. In more mature industries and where the pace of technological change is rapid, “contestability” or potential competition may yield benefits similar to what could be achieved with full competition, further reducing the role of government or need for regulation.

### Hypothetical Marketization Pathway

- **Increasing Private Control**: Reducing Government Role
- **Privatization**: Increasing private ownership
- **Commercialization**: Delegating management and selling state controlled sectors
- **Face competition**

### Deregulation/Re-regulation

- **Regulation**: Establishing regulation
- **Delegation**: Establish regulatory rules
- **Identify regulatory function**
- **Establish regulatory rules**

### Re-regulation/Re-regulation

- **Reduce or alter regulatory role**
- **Decrease price-regulation role**
- **Increase competition**

### Non-attainment area of high risk/reserve position and favorable policies.

- **Worldwide risk capital equilibrium**: Capital will flow to high risk/policy constrained locations but only with substantial risk premisums.
- **Risk/Reserve Position**

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At the time of writing we have several anecdotal “tests” of this hypothesis. In the case of Saudi Arabia, the desire to maintain market share and assert domination on the world oil market scene, as well as to realign the value of natural gas resources, may provide sufficient motivation for a return to more open policies with regard to foreign participation. If this is true, the Saudis could move into the non-attainment area where currently no country is represented: the temptation for such a major reserve holder to control its petroleum and gas wealth, and the importance of controlling their oil export revenues for political objectives, otherwise is simply too powerful. On the other hand, Angola, for example, appears to be moving in the other way. Prolific offshore discoveries appear to be triggering a reconsideration of the favorable fiscal terms Angola had been offering. If so, Angola will decline in attractiveness for private, foreign direct investment upstream. China and Brazil are transitioning toward market-based policies for energy.

Both are faced with growing demand, inadequate domestic resources, and environmental imperatives. Russia and other new independent republics, especially the resource-rich countries of the Caspian region, are attractive to international energy companies, at least based on resource potential; but, investment conditions are poor with inadequate frameworks for private capital inflows and risk management. Importantly, political risk and uncertainty can have a devastating impact on any country’s relative position and comparative advantage. The approximate relationship of risk/reserve positions and government policies bears striking resemblance to the distribution of producing countries when reserves are correlated with production (see chart below). The prevailing conclusion is that for countries less well endowed to attract global capital flows for upstream development, government policies (commercial frameworks for upstream) primarily fiscal terms for access to prospective areas for exploration and generally be more efficient and more responsive to the needs of the public than those owned and operated by the state. Many countries have already reaped the benefits of privatization. In the longer run, commercialization proves to be a bridge between private and regulatory economic reform. This connection, however, requires effective regulatory reform in the majority of EMEs. In most cases, this reform entails creation of relatively independent regulatory commissions and regulatory rules in order to prevent monopoly activity by private owners and operators. The following graph reflects the relationships among these programs.

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production) must be that much more attractive. These relationships are not static, and experience and learning heavily impacts both investor and host government positions.

A similar approach can be used to approximate the relative relationships and distribution of best practices for the combined natural gas and electric power value chains. One such example is shown below. Here, the illustration links private investment access across the value chains for upstream natural gas, midstream pipelines, downstream power generation, wholesale natural gas and electric power, and retail natural gas and electric power. The objective is to assess, in a very broad way, “quality” of commercial frameworks to facilitate gas/power marketization in countries and regions where host governments have indicated some interest in fostering more open, liberalized treatment of these industries. Many exceptions exist to the very general relationships expressed in this chart.

For example, and notably, while much of the Middle Eastern countries within the “Petroleum Heartland” are not easily accessible, some countries have moved to provide at least elementary platforms for external investment flows (Qatar being such a case in point). Within West Africa, considerable progress has been made in countries like Côte d’Ivoire and Ghana. Political risk throughout the Petroleum Heartland (West Africa into the Commonwealth of Independent States or CIS, the former Soviet Union republics) complicates the best intentions within governments. Even within established markets like the highly integrated Canada/U.S. system issues in both the quality of commercial frameworks as well as consistent applications of best practices across multiple jurisdictions and levels of jurisdictions can impede energy value chain development. Across all jurisdictions can impede energy value chain development. Across all

For one period, the future (compound) value is

\[ FV_1 = PV_0 (1 + i) \]

where \( i \) = interest rate per time period, and \( n \) = number of time periods.

For simple interest, the present value of the loan is

\[ PV_0 = I / (I x n) \]

where \( I = \) simple interest in dollars, \( PV_0 = \) principal amount at time 0, \( i = \) interest rate per time period, and \( n = \) number of time periods.

The future value (amount due at time \( n \)) using simple interest is

\[ FV_n = PV_0 + I \quad \text{or} \quad FV_n = PV_0 + (PV_0 x i x n) = PV_0 [1 + (i x n)]. \]

Compound interest is due not only on the principal but on prior interest which has not been paid (or withdrawn). The amount of interest due each period is the interest rate times the principal amount at the beginning of the period.

For one period, the future (compound) value is

\[ FV_1 = PV_0 (1 + i) \]

and for two periods, the future value is

\[ FV_2 = FV_1 (1 + i) \quad \text{or} \quad FV_2 = PV_0 (1 + i)(1 + i) = PV_0 (1 + i)^2. \]
Capital Budgeting

The capital budgeting process can be broken into four steps:
1. Generating capital investment project proposals.
2. Estimating cash flows.
3. Evaluating alternatives and selecting projects to be implemented.
4. Reviewing or post-auditing prior investment decisions.

The initial step in the capital budgeting process is generating capital investment project proposals. The process of soliciting and evaluating investment proposals varies greatly among companies. Investment projects can be classified as:
1. Projects generated by growth opportunities in existing product lines or new lines.
2. Projects generated by cost reduction opportunities, and
3. Projects required to meet legal requirements and health and safety standards.

The size of an investment proposal frequently determines who has authority to approve the project. A very large outlay might require approval of the corporation president or board of directors and lower and lower levels of management can authorize successively smaller outlays. If an investment decision is critical and must be made fast, a lower level manager can approve it or it can bypass the normal time-consuming review process to reach the appropriate responsible manager as fast as possible.

Capital Budgeting Criteria

Net cash flow (NCF) is the foundation of all investment decisions. It converts technical estimates into a common unit—money. Only cash can be used to acquire assets and to make profit distributions to investors. Negative cash flows over an extended period of time reduce an organization’s ability to satisfy its financial obligations. This is why the decision criteria we will see in this chapter are based on the cash flow, rather than revenues or profit. We will study two capital budgeting criteria. These are the net present value (NPV) and internal rate of return (IRR).

Net Present Value

The net present value (NPV) of an investment project is defined as the present value of a stream of future net cash flows from a project minus the project’s net investment.

The net present value is:

\[
NPV = PV_{NCF} - INV,
\]

where:
- \(NPV\) = net present value
- \(NCF_t\) = expected net cash flow in period \(t\)
- \(n\) = expected project life
- \(k\) = cost of capital
- \(INV\) = initial investment

The NPV decision rule is to accept a project when the NPV is greater than zero (because, in this case, the present value of the project’s net cash flows exceeds the project’s net investment outlay) and to reject a project when its NPV is less than zero (the present value of the net cash flows is less than the outlay). What causes some projects to have positive or negative NPVs? When product and factor markets are not perfectly competitive, it is possible for a company to earn above-normal profits and invest in positive NPV projects. Some examples of conditions that allow above-normal profits include:

- Buyer preferences for established brand names,
- Ownership or control of favored distribution systems,
- Patent control of superior product designs or production techniques,
- Exclusive ownership of superior natural resource deposits,
- Inability of new companies to acquire necessary factors of production (management, labor, equipment),
- Superior access to financial resources at lower costs (economies of scale in attracting capital),
- Economies of large-scale production and distribution arising from capital intensive production processes and high initial start-up costs, and
- Access to superior labor or managerial talents at cost which are not fully reflective of their value.

Example:

Let us revisit our example in Section I, and calculate the net present value of each project. First, assume that the company requires a 10% after tax rate of return, that is, \(k = 0.1\).

\[
NPV(A) = 50(1.01^0 - 0.01(1.01)^0 - 50(1.01)^0 - 50(1.01)^0) - 100 = 58.49
\]

\[
NPV(B) = 20(1.01^0 - 0.01(1.01)^0 - 40(1.01)^0 - 60(1.01)^0 - 80(1.01)^0) - 100 = 50.96
\]

\[
NPV(C) = 80(1.01^0 - 0.01(1.01)^0 - 20(1.01)^0 - 20(1.01)^0) - 100 = 59.27
\]

\[
NPV(D) = 40(1.01^0 - 0.01(1.01)^0 - 60(1.01)^0 - 40(1.01)^0 - 60(1.01)^0) - 100 = 60.00
\]

\[
NPV(E) = 10(1.01^0 - 0.01(1.01)^0 - 20(1.01)^0 - 70(1.01)^0 + 110(1.01^0) - 100 = 53.34
\]

The basic framework for capital budgeting is widely employed. Economic theory demonstrates that the company should expand its output until marginal revenue equals marginal cost. In capital budgeting, the company should invest in its most profitable projects first and should continue accepting projects as long as the last project’s rate of return exceeds the marginal cost of funds to the company. Some practical problems are encountered when using this capital budgeting model.

All capital projects may not be known to the company at one time. Changing markets, technology, and corporate strategies can make some current proposals obsolete and make new ones profitable.

2. Estimates of future costs and revenues can be made subject to varying degrees of uncertainty.
According to the net present value calculations, Project D is the best option and Project C is the second best. Project E is the second worst alternative despite the largest straight sum of cash flows ($120) it provides. Overall, projects are ranked from best to worst as follows: D, C, A, E, and B. This ranking may change if the company requires a higher rate of return, say 20%.

NPV(C) = 50(1+0.2) + 40(1+0.2)^2 + 60(1+0.2)^3 + 80(1+0.2)^4 - 100 = 99.75
NPV(D) = 50(1+0.2) + 40(1+0.2)^2 + 60(1+0.2)^3 + 80(1+0.2)^4 - 100 = 99.20
NPV(E) = 50(1+0.2) + 40(1+0.2)^2 + 60(1+0.2)^3 + 80(1+0.2)^4 - 100 = 98.65

When the company discounts the future returns more, that is, the returns further in the future are less valuable to the firm, Project E becomes the worst option whereas Project C becomes the best investment opportunity despite the lowest straight sum of cash flows ($90) it provides. Now, the projects are ranked from best to worst as follows: C, D, A, B, and E. The following chart provides a visual representation of the rankings and demonstrates how the ranking and project NPVs change as we change the discount rate.

Comparison of Projects

<table>
<thead>
<tr>
<th>Project</th>
<th>NPV @ 10%</th>
<th>NPV @ 20%</th>
</tr>
</thead>
<tbody>
<tr>
<td>A</td>
<td>100</td>
<td>70</td>
</tr>
<tr>
<td>B</td>
<td>90</td>
<td>60</td>
</tr>
<tr>
<td>C</td>
<td>80</td>
<td>50</td>
</tr>
<tr>
<td>D</td>
<td>70</td>
<td>40</td>
</tr>
<tr>
<td>E</td>
<td>60</td>
<td>30</td>
</tr>
</tbody>
</table>

In practice, NPV calculations take into account the many complexities of capital budgets. These include variations in timing of expenditures and revenues; complex tax rules; and depreciation, amortization and depletion allowances.

Internal Rate of Return
One of the most common methods used to calculate the return on investment for a capital expenditure project is the internal rate of return (IRR) method, or discounted cash flow (DCF) method, as it is often called. The internal rate of return (IRR) is defined as the rate of discount that equates the present value of net cash flows of a project with the present value of the net investment. In other words, the IRR is the discount rate which makes a project’s NPV equal zero. The algebraic definition of the IRR is:

\[ \sum_{t=1}^{n} \frac{NCF_t}{(1 + r)^t} = 0 \]

where \( r = IRR \).

The IRR decision rule is to accept a project when its IRR exceeds the cost of capital \( (k) \), for example, the interest rate on borrowed money, and to reject a project when its IRR is less than \( k \). Like the NPV, the IRR takes account of the magnitude and timing of a project's net cash flows over its entire life. One occasional difficulty with the IRR is that an unusual cash flow pattern (cash flows switching signs from positive to negative and vice versa) can result in multiple rates of return.

When two or more mutually exclusive projects are acceptable using the IRR and NPV criteria, and if the two criteria disagree on which is best, the NPV criterion is generally preferred. Both the NPV and IRR criteria will always agree on accept/reject decisions (i.e., if NPV > 0, then IRR > k; and if NPV < 0, then IRR < k), even if the NPV and IRR do not rank the projects the same. Different rankings result from the implicit reinvestment rate assumptions of the two techniques: the NPV assumes that cash flows over the project's life may be reinvested at the cost of capital \( k \) while the IRR assumes that cash flows may be reinvested at the IRR.

Example: Using our example from Section I, let us calculate IRR for each investment project.

\[ 50(1 + rA)^4 + 50(1 + rB)^3 + 50(1 + rC)^2 + 50(1 + rD) + 50(1 + rE) = 100 \]

Spreadsheet programs and financial calculators can calculate IRR very easily once you provide the net cash flows and the initial investment. All they do, however, is to solve for \( r \) in above equations. In our example, we obtain the following values for internal rate of return of each project:

\( rA = 35\% \); \( rB = 27\% \); \( rC = 45\% \); \( rD = 37\% \); \( rE = 26\% \).

These results rank the projects from best to worst as follows: C, D, A, B, and E. High values of IRR indicate that the company discounts future returns significantly. Since, in Project C, the most of the cash inflows are received during the first two years of operations, the company would have to discount the next year’s dollar at a rate of 45% for sum of the discounted net cash flows to equal the initial investment. Remember that the company is trying to recover the cost of capital. The cost of capital, \( k \), is less likely to be in the 40% range than in the 20% range.

Risk and Return Concepts
Risk refers to the potential variability of returns from a project. A project is considered risk-free if the monetary returns from a project are known with certainty. Probability distributions of the two techniques are the probability of every particular outcome. These probability distributions may be objectively or subjectively determined. The expected return is a weighted average of the individual possible returns,

\[ r = \sum_{ij} p_j r_j \]

where \( r \) is the expected return.

The standard deviation is an absolute measure of risk. It is defined as the square root of the weighted average of the squared deviations of individual observations from the expected value.

\[ z = \frac{r - r}{\sigma} \]

Risk is an increasing function of time with early returns being less risky than distant returns. One of the key variables in capital budgeting decisions is the cost of capital. The cost of capital can be thought of as what the company must pay for capital (interest rates on borrowing) or the return required by investors in the company's securities. Risk can also be thought of as the minimum rate of return required on new investments undertaken by the company. The cost of capital is determined in the capital markets and depends on the risk associated with the company's activities.

The weighted cost of capital is the discount rate used when computing the net present value of a project of average risk. Similarly, the weighted cost of capital is the hurdle rate used in conjunction with the internal rate of return. The weighted cost of capital is based on the after-tax cost of capital where the cost of the next (marginal) sources of capital are weighted by the proportions of the capital components in the company's long-range target capital structure. The weighted, or overall, cost of capital is obtained from the weighted costs of the individual components. The weights are equal to the proportion of each of the components in the target capital structure. The general expression for calculating the weighted cost of capital, \( k_a \), is:

\[ k_a = (equity fraction)(cost of equity) + (debt fraction)(cost of debt) \]
The appropriate component costs to use in determining $k_a$ are the marginal costs or the costs associated with the next dollar of capital to be raised. These may differ from the historical costs of capital raised in the past. The required return, $k$, on any security may be thought of as consisting of a risk-free rate of return plus a premium for the risk inherent in the security, or:

$$k = k_a + R_p$$

where $k_a = \frac{E}{B + E} (k_t + \frac{B}{B + E} (k_d (1 - T)))$

where $B = \text{amount of debt}$ and $E = \text{amount of equity}$.  

The risk-free rate of return is usually measured by the rate of return on risk-free securities such as short term government securities. The risk-free rate increases with expectations of future inflation. The risk-free rate depends on the overall supply and demand for funds in the economy. There are five major risk components, which determine the risk premium on a security.

1. **Business risk** arises from the variability of the company's operating income and is determined by the variability of sales revenues & expenses and the amount of operating leverage the company uses.

2. **Financial risk** arises from the additional variability of the net earnings associated with the use of financial leverage together with the increased risk of bankruptcy associated with the use of debt.

3. **Marketability risk** refers to the ability to quickly buy and sell the securities. Securities that are widely traded have less marketability risk than those which are less actively traded.

4. **Interest rate risk** refers to the variability in returns on securities arising from changes in interest rates. Increases in interest rates reduce the market price of the security. Decreases in interest rates reduce the rate at which intermediate interest payments can be reinvested.

5. **Seniority risk** is the risk due to the priority of a security's claim in a company's capital structure.

Regardless of the specific source of financing used at a particular time, a weighted cost of capital dependent on the component costs and the proportions of the components in the target capital structure is used for capital budgeting decisions. With respect to oil and gas operations, there are specific aspects of risk within the broad categories described above.

1. **Geologic risk.** For both the exploration and production (upstream) businesses, there is considerable geologic risk associated with the occurrence of oil & gas. Any number of factors contributes to risk — whether oil & gas occur in "commercial" quantities (relative to commodity prices and costs of extraction), the quality of the reservoir, success of any reservoir treatment, and so on.

2. **Engineering risk.** For the upstream and downstream (processing, refining, transportation, chemicals, marketing) businesses, there is risk associated with engineering design of infrastructure requirements.

3. **Market risk.** For the oil and gas industries, this source of risk is tied to supply and demand conditions in specific regions and worldwide.

4. **Commodity price risk.** There is risk inherent in the prices for oil & gas both locally and worldwide. Trading and speculation may contribute to risk while serving as strategies for managing price risk.

5. **Financial risk.** The cost of financing (interest rates, terms & conditions) is a large source of risk.

**Incremental Cash Flow Analysis.**

The capital budgeting process is concerned primarily with the estimation of the cash flows associated with a project, not just the project's contribution to accounting profits. Typically, a capital expenditure represents an initial cash outlay, termed the initial investment. Thus, it is important to measure a project's performance in terms of the net (operating) cash flows it is expected to generate over a number of future years. The chart in the following page represents a typical cash flow diagram. Estimating the cash flows associated with investment projects is crucial to the capital budgeting process. The cash flows associated with a project are the basis for evaluation rather than the project's accounting profits. There are several rules concerning the estimation of cash flows:

1. Cash flows should be measured on an incremental basis. The cash flow stream for a project is the difference between the cash flows to the company with the project compared to the cash flows to the company without adopting the project.

2. Cash flows should be measured on an after-tax basis.

3. All the indirect effects of a project should be included in the cash flow estimates. For example, increases in cash balances, receivables, and inventory necessitated by a capital project should be included in the project's net investment.

4. Sunk costs should not be considered. Since they result from previous decisions, sunk costs are not truly incremental costs.

5. Resources should be measured in terms of their opportunity costs. The opportunity costs of resources are the cash flows they would generate if investment were made in an alternative opportunity rather than in the project under consideration.

**Cash Flow Diagram**

![Cash Flow Diagram](Image)

**Estimating the Initial Investment.**

The initial investment is the initial cash outlay for a project (usually at time zero). A four-step procedure for estimating the net investment can be summarized as follows:

**Step 1.** The new project cost plus any installation and shipping costs associated with acquiring the asset and putting it into service, PLUS

**Step 2.** Any increases in net working capital initially required as a result of the new investment, PLUS

**Step 3.** The net proceeds from the sale of existing assets when the investment is a replacement decision, PLUS or MINUS

**Step 4.** The taxes associated with the sale of the existing asset and/or the purchase of a new one, EQUALS

The initial investment.

Some projects involve outlays for more than a year. The net investment for a multiple-period investment is the present value of the series of outlays discounted at the company's cost of capital. Reviewing or post-auditing is a final step to review the performance of investment projects after they have been implemented. While projected cash flows are uncertain and one should not expect actual values to agree with predicted values, the analysis should attempt to find systematic biases or errors by individuals, departments, plants, or divisions and attempt to identify
reasons for these errors. Another reason to audit project performance is to decide whether to abandon or continue projects that have done poorly. Inflation is easily incorporated into the basic capital budgeting criteria. Make sure that capital takes account of inflationary expectations. Make sure that future cash flow estimates also include expected price and cost increases. If these are done, the capital budgeting techniques outlined in this chapter serve the financial decision maker reasonably well.

If a project generates additional revenues and the company extends credit to its customers, an additional investment in accounts receivable is required. Moreover, if additional inventories are necessary to generate the increased revenues, then an additional initial investment in inventory is required, too. This increase in initial working capital -- that is, cash, accounts receivable, and inventories -- should be calculated net of any automatic increases in current liabilities, such as accounts payable or wages and taxes payable that occur because of the project. As a general rule, replacement projects require little or no net working capital increase. Expansion projects, on the other hand, normally require investments in additional net working capital.

**Estimating the Annual Operating Cash Flows**

The expected future net operating cash flows (NCF) are easily computed. The after-tax net operating cash flow is:

\[ NCF = \Delta OEAT + \Delta Dep - \Delta NWC \]

where

- \( \Delta OEAT \): change in earnings after tax
- \( \Delta Dep \): change in depreciation
- \( \Delta NWC \): increase in the net working capital investment

\[ \Delta OEAT = \text{change in earnings before tax} \]

\[ \Delta Dep = \text{depreciation} \]

\[ \Delta NWC = \text{increase in working capital} \]

\[ T = \text{tax rate} \]

And

\[ \Delta OEAT = \Delta RO - \Delta RO_0 \]

where

- \( \Delta RO \): net operating cash flow
- \( \Delta RO_0 \): operating cash flow (at initial stage)

Based on these definitions, two useful expanded versions of the basic NCF equation are:

\[ NCF = (\Delta RO - \Delta RO_0 - \Delta Dep - \Delta NWC) \]

\[ = (\Delta RO - \Delta RO_0 - \Delta Dep - \Delta NWC - \Delta RO_0 - \Delta NWC) = (\Delta RO - \Delta RO_0 - \Delta Dep - \Delta NWC) \]

**Estimating the Terminal Year Cash Flows**

There are two potential cash flows at the end of a project’s life. First, cash inflow due to incremental salvage must be included at the end of the project. Incremental salvage is the difference between salvage with the project and without the project. There will be taxes due or saved when an asset is sold for more or less than book value. Book value is the installed cost of the asset less accumulated depreciation. There are four possible tax situations:

1. **Case 1:** Sale of an asset for book value. No tax consequences.
2. **Case 2:** Sale of an asset for less than book value. The loss is treated as an operating loss to offset operating income. The tax saving is the marginal tax rate times the amount of the loss.
3. **Case 3:** Sale of an asset for more than book value but less than original cost. The gain is taxed as operating income, with taxes due equal to the marginal tax rate times the amount of the gain.
4. **Case 4:** Sale of an asset for more than original cost. The part of the gain that represents a recapture of depreciation is treated as an operating gain and the gain in excess of original cost is treated as a capital gain.

Don’t forget that the recovery of book value is tax-free. Only gains and losses from book value result in tax savings or obligations. Also, recovery of net working capital can be a cash inflow. There are no tax consequences of liquidating working capital.

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**CHAPTER 8
PROJECT FINANCE**

Before the 1970s, most energy projects were financed by internal cash generation of international oil companies. In the 1970s, governments got involved in the energy sector to ensure better control of their reserves, the financing of oil and gas projects by governments and official borrowings increased. In the past twenty years there has been a wave of global interest in project finance as a tool for investment. In the early 1990s, many governments have limited their involvement in the sector to promote private participation. Thus, the financing became more complex, involving public and private investors and financiers. Project finance helps finance new investment projects by structuring the financing based on the project’s own operating cash flow and assets, with additional sponsor guarantees. The use of project finance tends to reduce investment risk and raise capital at a relatively low cost, to the benefit of sponsor and investor alike.

The change in attitude toward project finance can be attributed to a number of factors. Primarily, most countries today rely on market mechanisms to guide their economic activity and on the private sector to supply investment. Greater focus on the private sector has necessitated more regulatory reforms, which in turn have created a new market in areas previously seen as the preserve of government activity. These trends are particularly true for the energy sector, especially in power generation. For example, in 2003, project financings in the power sector ranked first, accounting for $40 billion with 123 projects (a 66% increase from 2002). Oil and gas investments ranked third with 40 deals worth $16 billion and nine petrochemicals deals worth $8 billion came fourth. Total value of project financings in 2003 was $108 billion as compared to $79 billion in 2002.

**Types of Project Finance**

Project finance is tailored to meet the needs of a specific project. Repayment of the financing relies on the cash flow and the assets of the project itself. The risks (and returns) are borne by different classes of investors (equity holders, debt providers, quasi-equity investors). Because risks are shared, one criterion of a project’s suitability for financing is whether it is able to stand alone, as a distinct legal and economic entity. Project assets, project-related contracts, and project cash flows need to be separated from those of the sponsor. See Appendix 1 for a typical deal structure for a project-financed project, and Appendix 2 for a new list of top 10 project finance deals in 2003 (amounting to almost $25 billion).

Corporate financing is when the borrowing is carried out by a utility as a whole rather than by an entity that holds the asset under the new facility. Although the funds may be invested into a particular project, lenders in a corporate financing arrangement look at the cash flow and assets of the entire company to service the debt and to provide security.

There are two basic types of project finance: non-recourse project finance and limited-recourse project finance.

**Non-recourse project finance**

An arrangement under which investors and creditors financing the project do not have any direct recourse to the sponsors, as might traditionally be expected (for example, through loan guarantees). Although creditors’ security will include the assets being financed, lenders rely on the operating cash flow generated from those assets for repayment. Before it can attract financing, then, the project must be carefully structured and provide comfort to its financiers that it is economically, technically, and environmentally feasible, and that it is capable of servicing debt and generating financial returns commensurate with its risk profile.

**Limited-recourse project finance**

Permits creditors and investors some recourse to the sponsors. Investments into the project are viewed as assets of the project company. The arrangement takes the form of guarantees, warranties, completion guarantee during a project’s construction period, or other assurances of some form of support for the project. Creditors and investors, however, still look to the success of the project as their primary source of repayment. They are more willing to invest in developing market projects and in other projects with significant construction risk, project finance is generally of the limited-recourse type.

Funds for a project come in the form of equity or debt (see previous chapter on project evaluation). The equity is provided by owners, shareholders, and sponsors that receive payments dividends and capital gains based on the company’s net profit. For oil and gas projects, mean leverage ratio is around 65%, and for power projects, it is around 70%. The possible sources of equity include sponsor’s own capital, investment funds, multilateral institutions, international equity markets, and local capital markets.

Project debt refers to funds lent by financiers such as commercial banks, financial institutions, and other funds. These loans are secured by the project’s underlying assets. Lenders receive payments for principal and interest on these loans according to a predetermined rate, regardless of whether the company makes or loses money. However, prospective lenders examine the company’s projected cash flow very carefully to ensure that there is sufficient financial capacity for debt repayment. Debt makes up to 60-80% of the project cost and is provided through institutional investors, international commercial banks, the International Financial Corporation (IFC), international bond markets, suppliers’ credits and special energy funds, as well as governments.

**Advantages of Project Finance**

Project finance has two important advantages over traditional corporate finance; it can

- increase the availability of funds, and
- reduce the overall risk for major project participants down to an acceptable level.

In order to attract such financing, though, a project needs to ensure that all the parties’ obligations are negotiated and are contractually binding.
Financial and legal advisers and other experts may have to spend considerable time and effort on this structuring, and on a detailed appraisal of the project. These steps will add to the cost of the project and may delay its implementation. Moreover, the sharing of risks and benefits brings unrelated parties into a close and long relationship. A sponsor must consider the implications of its actions on the other parties associated with the project (and must, therefore, consider fairly if the relationship is to remain harmonious over the long term.

Under project finance, there are several major benefits and advantages for stakeholders:

Control benefits

include the owners’ discretion to reinvest free cash flows in projects of their own choice, ability to pay themselves high salaries and bonuses, and their freedom in decision-making for their own interests at the expense of lenders or shareholders.56

Non-recourse benefit

The typical project financing involves a loan that is completely “non-recourse” to the sponsor, i.e., the sponsor has no obligation to make payments on the project loan if revenues generated by the project are insufficient to cover the principal and interest payments on the loan. In order to minimize the risks associated with a non-recourse loan, a lender typically will require indirect credit supports in the form of guarantees, warranties and other covenants from the sponsor, its affiliates and other third parties involved with the project.

Benefits of leverage maximization

The sponsor typically seeks to finance the costs of development and construction of the project on a highly leveraged basis. Frequently, such costs may be financed through 50 to 100 percent debt. High leverage in a non-recourse project financing permits the sponsor to put less in funds at risk, permits a sponsor to finance the project without diluting its equity investment in the project, in certain circumstances, also may permit reductions in the cost of capital by substituting lower-cost, tax-deductible interest for higher-cost, taxable returns on equity.

Off-Balance-Sheet treatment benefit

Depending upon the structure of a project financing, the project sponsor may not be required to report any of the project debt on its balance sheet because such debt is non-recourse or of limited recourse to the sponsor. Off-balance-sheet treatment can have the added practical benefit of helping the sponsor comply with covenants and restrictions relating to borrowing funds, and other indents and credit agreements to which the sponsor is a party.

Maximization of tax benefits

Project financings should be structured to maximize tax benefits and to assure that all available tax benefits are used by the sponsor or transferred, to the extent permissible, to another party through a partnership, lease or other structure.

Benefit of capturing an economic rent

The sponsors of the project can monetize the economic rent by entering into long-term purchase contracts that can be used to secure project borrowings to finance the project. Such contracts could also generate the cash flow to service project debt and provide equity investors the return of and return on their investment.

Achieving economies of scale

Two or more producers can benefit from joining together to build a single facility when there are economies of scale in production. For example, the firms in a densely industrialized area might decide to cooperate in a single cogeneration facility, with each firm agreeing to buy steam to meet its own needs for heat and the group selling all the excess electricity to the local electric utility.

Risk sharing

If a project’s capital cost is large in relation to sponsor’s capitalization or financial capabilities of the host country, to reduce their own risk exposure they can enlist one or more joint-venture partners.

Lower overall costs of funds

If the output purchaser’s credit standing is higher than that of the project sponsors, the project will be able to borrow funds more cheaply than the project sponsors could on their own. Also, to the extent the project entity can achieve a higher degree of leverage than the sponsors can comfortably maintain on their own, the project’s cost of capital will benefit from the substitution of lower-cost debt for equity.

Reduced cost of resolving financial distress

A project entity’s capital structure typically has just one class of debt, and the number of other potential claimants is likely to be small. The entity with such capital structure tends to emerge from financial distress more easily.

Reduced legal or regulatory costs

Certain types of projects, such as cogeneration projects, involve legal or regulatory costs that the experienced project sponsor can bear more cheaply than an inexperienced operator can.

Disadvantages of Project Finance

Because the risks assumed by lenders may be greater in a non-recourse project financing than in a more traditional financing, the cost of capital may be greater than with traditional financing. Complexity of project financing. Project financings are extremely complex. It may take a much longer period of time to structure, negotiate and document a project financing than a traditional financing and the legal fees and related costs associated with a project financing can be very high.

Indirect credit support

The cost of debt is typically higher in a project financing because of the indirect nature of the credit support. Lenders to a project will naturally be concerned that the contractual commitments might somehow fail to provide an uninterrupted flow of debt service, and as a result they typically require a higher yield premium to compensate that risk, that is generally between 50 and 100 basis points (could be up to 400 basis points), depending on purchase contract negotiated (under any circumstances contract provides a greater degree of credit support).

Higher transaction costs

Higher transaction costs reflect the legal expense involved in designing the project structure, researching and dealing with project-related tax and legal issues, and preparation of necessary project ownership, loan documentation and other contracts.

Limited managerial decision-making

Extensive contracting restricts managerial decision-making.

Disclosure of strategic information

Project finance requires greater disclosure of proprietary information and strategic deals.

Project Risks

Since project finance structuring hinges on the strength of the project itself, the technical, environmental, economic viability of the project is a big concern. Anything that could weaken the project is also likely to weaken the financial returns of investors and creditors. Therefore, an essential step of the procedure is to identify and analyze the project’s risks to identify and mitigate them, usually by entering into guarantee and contractual arrangements. The various risks that concern energy project lenders can include the following:

Construction:

Will the project be on time? Will the project be on budget? Is the contractor capable of delivering what he’s agreed to? Does he have sufficient assets in the event he does not deliver? Will some act of God, force majeure or other physical loss impede or otherwise upset the project?

Operations:

Will the project be properly maintained? Is the O&M contractor qualified and experienced? Will the project perform efficiently and at predicted capacity levels? Will there be labor difficulties, unplanned outages, physical losses and income losses caused by acts of God? Equipment: Is the chosen equipment suitable for the project? Will it be delivered on time? Will replacement parts be readily available? Is there a technology risk? What is the stability of the manufacturer? Does it have sufficient assets in case of a fleet wide failure?

Economic:

Will there be unexpected costs, problems with currency conversion, repatriation of funds, tax changes, and/or policy changes? Will sinking funds and government agreements be sufficient or reliable?

Market Availability:

Will the project have the ability to sell power/gas/liquids at sufficient rates to assure debt service and project health? Is the credit rating of the purchase agreements (e.g., PPAs), if any, sufficient? What is the ability of the government to back these agreements? What is the value of the country’s sovereign guarantee?

Political:

A number of political or cross border risks may need to be addressed such as state ownership, power sales, taxes, fuel use, emissions, currency, contract repudiation, expropriation, nationalization, insurgency. Fuel Supply Resource Reliability: Depending on the technology being used, different fuel reliability issues are common. The long-term supply contracts or agreements, the fluctuation in fuel prices, reliability of resource studies, weather risk such as a lack of sufficient wind speeds or hours of sunshine for wind and solar projects.

Clearly, project risks are many and varied. These risks are related to events that could endanger the project during development, construction, and operation. Some may relate to a specific sub-sector, others to the country and policy environment, and still others to more general factors. But, in general, financing projects in the developing world is considered more risky than in developed world primarily due to: (1) deficiencies in institutional and organizational structures, (2) lack of clear and transparent legislative and regulatory systems, (3) economic and political insecurity, (4) market/price risk for the commodity to be produced, (5) financial risks, (6) currency risks (risks of devaluation of cash flows nominated on local currency), and (7) increased force majeure risk. These risks endanger the viability and sustainability of the project through (1) excessive construction and operation costs, (2) shortfall in revenue or the margin

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Project risks are usually borne by project sponsors. Accordingly, identification, analysis, mitigation, and allocation of project risks are essential to structuring project finance deals. Although it may be costly and time consuming to bear the risk, it is necessary to assure other parties, including passive lenders and investors, that the project makes sound economic and commercial sense. Similarly, lenders and investors are likely to demand that the project's performance be linked to the project's ability to repay debt as it progresses. This risk assessment and mitigation process is one of the reasons for higher transaction costs associated with project financing.

Project Financing Across the Energy Value Chain

Upstream

From the financing of oil and gas rigs to oil refineries and pipelines, oil and gas companies are increasingly using project financing as a method of reducing corporate debt by taking heavy capital investment off the company’s balance sheet. Large international oil companies (IOCs) usually finance the upstream oil and gas projects by internal cash generation and corporate borrowings. Smaller IOCs borrow funds on non-recourse or limited recourse basis.

One of the projects financed by the project finance is the Azerbaijani International Oil Consortium (AIOC), consisting of 11 members. In 1999, the AIOC completed the early oil project, producing 100,000 barrels of crude oil a day. In 2000, the project included the Chirag-1 platform, the construction of a new onshore terminal at Sangachal and a 230-km subsea pipeline system, the rehabilitation of two existing export pipelines to transport early oil to the Black Sea, via two routes: one through Russia to Prorsiyasky and then through Georgia to Supsa.

The AIOC was organized as an unincorporated joint venture between subsidiaries from each company. Each of them was responsible for financing its share. So, each partner had a choice in how to finance its share in the project. Six members with closed interests of 48.2% chose to use internal funds. For example, BP contributed around $325 million to cover its share (17.1% of $1.9 billion). The other five members of the AIOC formed a Mutual Interest Group (MIG) for the purpose of obtaining project loan from the International Finance Corporation (IFC), and the EBRD. These multilateral agencies gave these companies access to long-term funds that banks were not willing to provide. In February 1999, the IFC, EBRD and MIG closed a $400 million, limited recourse project financing, with the effective interest rate of less than 11.9% (the 3-year, $400 million loan). The guarantee included severe penalties for failing to meet performance requirements and the IFC project guarantee covered 90% of the other project risks.

One example of project finance in the upstream sector is the Petrozuata, Petrózutu C.A., a $2.5 billion joint-venture of Conoco (50.1%) and state-owned Petroleos de Venezuela, S.A. (PDVSA) (49.9%), oil-field development project in Venezuela. The Petrozuata sponsors made significant commitments in order to ensure successful implementation of the project. They agreed to provide funds to Petrozuata to pay project expenses, including any cost overruns, up to 49% of the project’s cost. The parent corporations of the sponsors guaranteed these obligations in the amount of $1.4 billion. The guarantee structure was unique considering differences in ratings between the companies (Du Pont AAA, Petrozuata would not complete the project by December 2001, all debt terms were non-recourse to Petrozuata’s shareholders. The completion guarantee included severe penalties for failing to meet obligations, and incentives to cover the other party’s shortfall. The construction budget also contained a $38-million contingency for upstream facilities, a $139-million contingency for downstream facilities and enough funds to pay premiums on a construction all-risk insurance policy covering up to $1.5 billion of physical loss or damage.

Once Petrozuata completed construction, the sponsors’ guarantees would end, and project debt would become non-recourse to the sponsors. If Petrozuata would not operate the project by December 2002, all sponsors would immediately become due and payable. On the 15th of March, 2002 Petrozuata announced that all performance requirements associated with the project financing have been met, and the institutional debt becomes non-recourse to Petrozuata’s shareholders.

Pipelines

In the U.S., a few natural gas pipelines have been financed through project finance. Examples are the Kern River and Mojave Pipelines in the early 1970s, and a number of other projects including the example of the U.S.-Canadian Alliance Pipeline capable of transporting 1.325 billion cubic feet of natural gas daily from northeastern British Columbia to the Chicago-area market for distribution throughout North America. Alliance partners are Coors Coca-Cola (14.4%), Evergreen Energy, Inc. (16.2%), Fort Chicago Energy Partners LP (26%), IPL Energy Inc. (21.4%), Unocal Corporation (9.1%), Westcoast Energy Inc. (14.5%) and Williams Companies Inc. (8.9%). The cost of the pipeline was $3.1 billion with made it one of the biggest projects financed in North America. The debt and equity structure of the pipeline financing was 70%-30%. The U.S. side of the pipeline construction received a debt of $1.5 billion, while the Canadian side received $1.6 billion, with debts financed by Bank of Montreal, The Bank of Nova Scotia, the Chase Manhattan Bank, and Royal Bank of Scotland, and maturing in December 2008.

Internationally, there are two recent examples: Bolivia-to-Brazil natural gas pipeline and Chad-Cameroon oil pipeline. The Chad-Cameroon pipeline will carry oil produced from the fields at Doba in southern Chad over 1,070 kilometers (665 miles) of oil fields on Cameroon’s coast. The Chad government development will cost $1.5 billion and the pipeline will cost $2.2 billion. The project’s private sponsors (led by ExxonMobil, the operator, Petrobras, and Petrocameroon) are financing approximately $0.8 billion or 81% of the project costs from their own resources including 100% of the field facilities. About $600 million in debt financing for the export system has been obtained by the sponsors from export credit agencies and international banks. Other project stakeholders include the World Bank, IFC, governments of Chad and Cameroon, and even local communities and NGO’s. A major concern of the private participants is that despite the availability of the newly found oil wealth for the good of the majority in Chad, and, in particular, local communities that host the project. In response, the World Bank, with the collaboration of other stakeholders, implemented a remediation fund, a Management Plan, isolating Chad’s project revenues and targeting them to social development programs (see the Chad-Cameroon Pipeline case study for details on project financial and revenue management plan).

Bolivia – to - Brazil Pipeline, which is the longest pipeline built in Latin America at a cost of $2.2 billion, was financed by the World Bank, the Brazilian National Development Bank (BNDES), the Inter- American Development Bank (IADB), the European Investment Bank (EIB) and Corporación Andina de Fomento (CAF). The IFC and the World Bank provided $240 million in term loans (debt) and equity with the 63%-37% ratio. In 1997, the IADB and the World Bank approved loans to finance a significant portion of the Bolivia- Brazil pipeline. The IADB approved $240 million in term loans (debt) and equity. These loans went to finance Petrobras, the Brazilian state-owned energy company, the principal investor and operator of the pipeline in Brazil. The ownership of the pipeline in Brazil is TGB, whose investors include Petrobras, Transredes, Enron, Shell and BTB. Gas Transboliviano, a consortium comprised of Transredes, Enron, Shell, Petrobras and others, owns the Bolivian side of the pipeline. The Bolivian side ($84 million) was financed by the National Development Bank of Bolivia, which had been contracted to oversee pipeline construction in Bolivia, then decided to step in and provide the necessary guarantees for such financing package. However, multilateral financing and partial credit guarantees were not an option for the Bolivian side since the transportation company was structured as a fully private venture for which sovereign guarantees, required from the Bolivian Government for multilateral support, were not available. Nevertheless, the new owners of the transportation company in Bolivia were not coming up with the required financing and seemed not to attach the same urgency as Petrubras to close the pipeline financing and start the construction. It became clear to Petrobras that the Bolivian segment of the pipeline would be beyond 20% of overall costs which was impeding the realization of the entire project. Petrobras, which had also been contracted to oversee pipeline construction in Bolivia, then decided to step in and provide the necessary guarantees for the completion of the project as well (see Bolivia-to-Brazil pipeline case for details).

Electric Power

As some electricity markets are liberalized and government monopolies are unbundled and privatized, private sector companies are playing a pivotal role in building new generation capacity; they usually employ project finance with off-take agreements guaranteeing electricity sales. In emerging countries, expansion of electricity is imperative to economic growth and raising the standard of living. In the absence of sufficient government financing, project financing plays an important role in attracting private investors to these countries, where investment risks are usually higher. Accordingly, coal, oil and gas- fired power plants, hydroelectric, combined cycle power and gasification, and biomass power plants are being successfully delivered on a project finance basis around the world. There are numerous methods available for the financing of power projects in developing countries. These methods provide for various levels of participation and control by private (and sometimes foreign) investors.

- Management and operation contracts involve an outside private entity managing but not owning a public entity - often for a specified period of time. They involve the state ceding the least amount of control to private enterprise.
- Greenfield projects involve the construction of new power plants by private investors or by public- private ventures. They may be build- own-operate-transfer (BOO), build-operate-transfer (BOT), or build- lease-own (BLO) agreements.
- Divestitures allow the private firm to take a substantial equity stake in what was a domestic (and sometimes publicly owned) enterprise.

In terms of financing power projects, debt usually consists of commercial bank loans or bond issuances. Equity, on the other hand, usually consists of taking stock or ownership in the project or company. One instrument

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that balances the qualities of debt and equity is a subsidized loan, which is given repayment priority over equity capital, but not over commercial loans or other senior debt.

The selected project financing technique depends heavily on the creditworthiness of the country where the investment is taking place. Legal systems, environmental standards and political stability are some of the factors that determine a nation’s creditworthiness. The most obvious method for repayment of the costs of a power plant would be through the state, in the operation and maintenance of the developing countries are plagued by theft of electricity or tariff rates that cannot support the cost of the plant. For riskier power projects, state Export Credit Agencies often play a key role in providing loans, making guarantees to financiers of the project, or acting as an insurance facility. Developing countries are also recipients of major funding packages from multilateral and bilateral agencies or credit facilities, which have a function similar to that of ECAs.

Across the world, Americas and Pacific Asia stood out as major targets of project finance lending in the energy sector between 1998 and 2002. Over this period, $101 billion in the power sector and $20 billion in the oil & gas sector was financed in North and South America; the corresponding numbers in Pacific Asia were $20 billion and $13 billion. One of the most recent and interesting deals is the Umm al-Nar IWPP project in the United Arab Emirates (UAE) combined elements of long-term foreign investment, conventional debt financing and Islamic financing in challenging market conditions. The project included the financing of the acquisition of an existing 850-MW and 162 million imperial gallons per day (MIGD) water and desalination plant. The construction of 1,550 MW of new capacity, decommissioning of certain existing assets and operation of a combined new facility on Umm Al Nar Island in the Emirate of Abu Dhabi.

The purchaser was a new equity joint venture, Arabian Power Company, owned 40 percent jointly by wholly owned subsidiaries of International Power plc, the Tokyo Electric Power Company and Mitsui Co., Ltd., and 60% by a new holding company wholly owned by ADWEA. Capacity contracted output will be sold to the Abu Dhabi Water and Electricity Company, an affiliate of ADWEA and the “single buyer” for Abu Dhabi’s privatized water and electricity sector. The price of the acquisition of the plant and its finance was $670 million, and a 20-year power purchase agreement. The financing package included two non-recourse loans, a $1.1 billion 20-year term loan and a $230 million five-year term loan, in addition to a $440 million five-year equity commitment. The group was comprised of 14 international, regional and local financial institutions, with Bank of Tokyo- Mitsubishi acting as global coordinator and Abu Dhabi Islamic Bank as lead arranger for the Islamic facility.

The developing Asian countries typically have chosen to rely more on Independent Power Producers (IPPs). In Asia, 72% of 393 billion in private investment between 1990 and 1999 was directed to greenfield projects. Private sector involvement generally has been limited to generation while transmission and distribution continued to remain in the hands of the government. This has soon led to serious problems, however, as the highly politicized issue of determining fair tariff rates discourages the private sector from entering the market. Even when entry is encouraged, it is often through a variety of government and donor guarantees. Many IPPs have failed due to the lack of adequate institutional and regulatory framework, and some have also raised the cost.

PT Paiton Energy project was the first IPP to be financed in Indonesia, and one of the largest to have closed to date anywhere. Although the project’s revenue stream was similar to that of other local Electric Power Companies (DAEPC), the project was also a fundamental challenge in most emerging countries where investment in electricity is desperately needed to fuel and support economic growth: unless consumer prices can be brought to a level to reflect cost of investment, it will be very difficult to successfully develop projects.

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Asian financial crisis in late 1997 struck Indonesia hard, and by January 1998 the Indonesian government had indefinitely postponed or canceled many of the IPPs. The Indonesian economy collapsed amidst massive unemployment and the rupee/U.S. dollar. This economic disaster, coupled with allegations of corruption, political instability, and renewed resistance to privatizations, overwhelmed efforts to find a mutually acceptable solution to the problems of the IPPs. Paiton continued throughout this period to seek a negotiated solution with PLN and the Indonesian government. As the year progressed, though, the Ministry of Finance and other relevant government agencies remained very far apart on terms of an acceptable settlement. The Paiton PPA obligated PLN to make tariff payments in Indonesian rupee, not U.S. dollars. However, while the amount of the rupee payment was adjusted to assuage to PLN the appropriate amount of U.S. dollars at then-current exchange rates.

Critically, the PPA also provided that, if the project company was unable to obtain spot foreign- exchange contracts to promptly convert the rupee payments into U.S. dollars, then PLN instead was obligated to obtain the rupee payments through the Indonesian government. The government’s Ministry of Finance Support Letter covered all of the PLN obligations. Thus, the ultimate risk of foreign-exchange availability, convertibility, and fluctuation was allocated to the project company. The revised master agreement for the project also benefited from approximately $1.8 billion in direct loans and debt insurance provided by the U.S. and Japanese governments as export

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Sources of Funds

There are a few major agencies providing project financing in the energy sector. The main players could be divided into two categories: development financial institutions (DFIs) and export credit agencies (ECAs).

DFIs try to foster economic development, and include the World Bank and its International Finance Corporation (IFC) and Multilateral Investment Guarantee Agency (MIGA), European Bank for Reconstruction and Development (EBRD), European Investment Bank (EIB), Asian Development Bank (ADB), and others. ECAs try to help developing countries by export their goods and services into international markets, and operate on a country basis, such as the Overseas Private Investment Corporation (OPIC) and Export-Import Bank (EXIMBANK), Japan’s Export-Import International Cooperation (JEXIM), Export Development Corporation (EDC) in Canada, Export Credits Guarantee Department (ECGD) in United Kingdom’s Export Credit Guarantee Corporation (ECCG) and in France, Euler Hermes Kreditversicherungs-AG (HERMES) in Germany, etc.

These institutions are the catalysts for a large number of projects in different nations in which privatization of state energy operations and an increasing tendency for producing nations to enter the downstream market are encouraging private projects. Furthermore, barriers to foreign investment in domestic petroleum sectors are falling and oil and gas law reforms are under way especially in the developing world.

World Bank’s International Finance Corporation (IFC) offers a range of financing and advisory services that allow it to play a unique role in supporting private sector investments in oil and gas projects, such as its Paiton’s power project. EXIMBANK, was sealed in March 2003. As part of it, the Export Import Bank of the United States (EXIMBANK) would provide a US$381 million direct loan to Paiton’s power project. EXIMBANK, along with the Japanese Bank for International Cooperation, Nippon Export and Investment Insurance of Japan and the U.S, OPIC, were the major lenders to the project. In addition, commercial banks from the U.S., Europe, Japan, Australia and other Asian countries and bond holders also contributed to the project.

Projected Level and Composition of Financing Energy Operations

European Bank for Reconstruction and Development (EBRD)

was established in 1991. It exists to foster the transition towards open market-oriented economies in the former communist countries of central and Eastern Europe and the former Soviet Union, and to promote economic initiatives and effective corporate governance. It was established to assist U.S. companies investing in some 140 emerging economies around the world. OPIC provides funding through direct loans and loan guarantees that often serve as a basis for joint private sector ventures involving significant equity and/or management participation by U.S. businesses.

Project financing can provide on a project finance or a corporate finance basis. OPIC can provide medium- and long-term financing in countries where conventional financial institutions often are reluctant or unable to lend on such a basis. Since its programs support private sector investments in economically viable projects, OPIC does not offer concessionary terms usually preferred by private sector lenders.
associated with government-to-government lending, nor does it typically offer financing of export sales unrelated to long-term investments in overseas business. OPIC will not participate in projects that can secure adequate financing from commercial sources.

OPIC provides loan guarantees, which are typically used for larger projects, and direct loans, which are reserved for projects sponsored by or with Development Assistance (ODA), which aims at the economic development of private power and other infrastructure. This financing structure has been used successfully for oil and gas, mining, and power projects, as well as telecommunications, transportation and other sectors. Ex-Im Bank does not compete with private sector lenders but provides export financing products that fill gaps in trade financing. It assumes credit and country risks that the private sector usually is unwilling to accept and also helps to fill the funding field for U.S. exporters by means other than matching the financing that other governments provide to their exporters. Ex-Im Bank provides working capital guarantees (pre-export financing), export credit insurance (post-export financing); and loan guarantees and direct loans (buyer financing).

Japan Bank for International Cooperation (JIBC)

JIBC’s financial activities focus on projects in developing countries where local private financial institutions cannot cover financing on their own, due to the factors of unstable economic conditions and the necessities of long-term financing. As JIBC’s mandate is the support of internationalization for Japanese companies, its loans can be distinguished from Official Development Assistance (ODA), which aims at the economic development and improved well-being of developing countries. JIBC operates on two fronts in undertaking Japan’s external economic policy and economic cooperation. On one front it conducts International Financial Operations, which include export loans, import loans, overseas investment loans, united loans and equity participation in overseas projects of Japanese corporations. The other component of the operations of JIBC is the Overseas Economic Cooperation Operations, which provide financial assistance including ODA loans. The basic tenet of these operations is to provide concessionary long-term, low-interest funds needed for the self-help efforts of developing countries, including social infrastructure development and economic stabilization. More specifically, JIBC provides ODA loans in various forms attuned to the existing needs, Private Sector Investment Finance Supporting business activities in developing countries, and development-related research.

Export Development Corporation (EDC)

focused on supporting export and project financing for Canadian goods or services. EDC financing services extend beyond countries in which EDC has established lines of credit. EDC helps Canadian exporters and investors assess the long-term potential and manage the increased complexity and risk. In 2003, Canadian business concluded $45.4 billion in export and domestic sales and investments in markets using EDC trade financing services, up 13 per cent over the previous year. Financial services of EDC include credit insurance, bonding and guarantees, political risk insurance, direct loans to buyers and lines of credit in other countries to encourage buyers to "Buy Canadian." The Corporation also provides limited term, low-interest financing arrangements, and joint ventures for projects involving long-term leasing arrangements and equity participation.

Export Credits Guarantee Department (ECGD)

ECGD was originally set up in 1919 to help British exporters re-establish their market positions following the disruption caused by the Great War. This assistance largely took the form of providing insurance against the commercial and political risks of not being paid by overseas buyers after goods were exported. In 1991, the arm of ECGD which dealt with exporters who traded on short terms of credit (i.e. up to two years) was sold to NCM Credit Insurance Ltd. Exporters of this type of goods, e.g. consumable items, can now obtain credit insurance from a number of companies in the private market. ECGD still provide exporters of British capital goods and services with finance and insurance packages to help them win valuable overseas orders. ECGD can also insure British companies who invest abroad against the political risks of a non-return on their investments. ECGD issue around £3.5 billion of guarantees a year to cover a variety of exports ranging, for instance, from textile machinery to Uzbekistan to multimillion pound orders in China. 55% of ECGD’s domestic business covers support for overseas civil projects, 24% is for defense-related equipment and 21% is for civil aircraft (mostly Airbus). ECGD is also insuring over £800 million of overseas investments (e.g., an office building in Morocco).

SACE S.p.a., Servizi Assicurativi del Commercio Estero

the Italian export credit agency. SACE S.p.a.'s capital is fully owned by the Ministry of Economy and Finance, which appoints the members of the Board in agreement with the relevant ministries. SACE S.p.a. provides support for the internationalization of the Italian economy by ensuring and reinforcing political, economic and commercial risks to which Italian operators may be exposed in the process of their international transactions. The Agency is authorised to enter into insurance, reinsurance and co-insurance agreements covering risks of a political, catastrophic, economic and commercial nature and those inherent in exchange rate fluctuations to which Italian entrepreneurs may be exposed in their transactions abroad and, more generally, to promote the internationalisation of Italian economic undertakings.

With close to 60 years experience, Coface (http://www.coface.com/) facilitates transactions between companies throughout the world. It offers businesses an array of solutions to manage, finance and protect their commercial transactions, while giving them the option to outsource all or part of their trade receivables management. Two core businesses are at the disposition of Coface’s 83,000 customers (domestic/export credit insurance and other long-term achievements). Coface has a direct presence in 56 countries and through the CreditAlliance credit insurance network and the InfoAlliance credit information network, its geographic reach spans 91 countries. These two networks are built around an integrated product and service offer: the @rating Solution and a shared risk management system (Common Risk System). Coface is one of the world leaders in credit insurance and credit management services.

Euler Hermes Kreditversicherungs-AG (HERMES)

is the worldwide leader in credit insurance, the leading European group in trade financing and one of the leaders in bonding and guarantees. With 6,000 employees in 36 countries, Euler Hermes has a share of 36% of the global credit insurance market and offers a complete range of services for the management of customer receivables. A member of the Allianz group and subsidiary of AGF, Euler Hermes is listed on the Premier Marché of Euronext Paris. Standard & Poor’s rates the Group and its principal credit insurance subsidiaries A+.

Appendix 1. Diagram of a Typical Project-Financed Deal

Appendix 2. Top 10 global project finance deals 2003

<table>
<thead>
<tr>
<th>Borrower</th>
<th>Project</th>
<th>Country</th>
<th>Sector</th>
<th>Amount ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>2. CNOC Oil</td>
<td>NBP Petrochemical</td>
<td>China</td>
<td>Petrochemicals</td>
<td>4,900.00</td>
</tr>
<tr>
<td>3. Edgpower</td>
<td>Edgpower</td>
<td>Italy</td>
<td>Power</td>
<td>2,733.04</td>
</tr>
<tr>
<td>4. J-COM Finance</td>
<td>J-COM Refinancing &amp; Expansion</td>
<td>Japan</td>
<td>Telecom</td>
<td>2,696.00</td>
</tr>
<tr>
<td>5. Pendana Secure Communications</td>
<td>SkyNet5</td>
<td>UK</td>
<td>Defence</td>
<td>2,873.87</td>
</tr>
<tr>
<td>6. Espana Nacional de Anticipos</td>
<td>Espana Nacional de Anticipos</td>
<td>Spain</td>
<td>Road</td>
<td>1,346.95</td>
</tr>
<tr>
<td>7. Gazprom Power</td>
<td>Gazprom Power</td>
<td>UK</td>
<td>Utilities</td>
<td>1,577.50</td>
</tr>
<tr>
<td>8. PT Pertamina</td>
<td>PT Pertamina</td>
<td>Indonesia</td>
<td>Power</td>
<td>1,729.50</td>
</tr>
<tr>
<td>9. Aluminum Alumina</td>
<td>Aluminum Alumina</td>
<td>Brazil</td>
<td>Processing plant</td>
<td>1,900.00</td>
</tr>
<tr>
<td>10. HKS Power</td>
<td>HKS Power</td>
<td>Malaysia</td>
<td>Power</td>
<td>1,752.00</td>
</tr>
</tbody>
</table>
Economics of Exhaustible Resources

Fossil fuels (coal, oil and natural gas) have been the major sources of energy in the world for a long time. They are considered nonrenewable (or extractable) since it takes millions of years for these fuels to form in the earth’s crust. The fact that the store of oil and gas is finite may be a cause for concern, depending upon perceptions about how large that store is. For example, there were predictions that the production of oil in the U.S. would end within the 20th century, but additions to reserves proved those predictions wrong. Advances in technology, due in part to the oil price shocks of the 1970s, have helped to extend the ultimate life of the U.S. reserve base. The combination of higher oil prices and technology advances also resulted in additions to the world’s reserve base of oil and gas.

Nevertheless, it is a geological fact that oil and gas resources are not infinite (at least based on current knowledge). However, it may be more important to consider the “economic life” of the resource rather than the “geologic life.” For some oil and gas producing basins, the cost of extraction may increase faster than the increase in the price of oil or gas. This is the case when the reservoir is being depleted at a faster rate (or reserves are being added at a slower rate) than the general rise in oil and gas prices associated with gradual depletion of the worldwide resource base. In this example, the economic life of the resource is shorter than the geologic life. Importantly, the economic life of a basin, or its commercial viability, is always subject to change given technology changes, and disruptions in oil and gas prices, as well as the attractiveness of competing investment opportunities.

A critical question is whether oil and gas resources are being depleted too rapidly (for instance, by inadequate conservative practices) or too slowly (for instance, by cartel limiting its production in order to raise prices). In either situation, we are most concerned with the optimal rate of production. This rate is likely to differ between companies (or countries) as well as under different market conditions. Most probably, all of these situations will be different from the “socially optimal” rate. The latter, which is qualitatively equivalent to competitive outcome, is the case we will demonstrate.

Optimal Depletion

The objective of the resource owner (a company or a country) is to allocate the resource over time in such a way to maximize its value (profit or social welfare) if we assume a “fixed” amount of the resource. There are several imperfections affecting the solution to this problem:

- Exercise of market power by a group of producers,
- Environmental concerns about the production and consumption of fossil fuels,
- Uncertainty of discovery,
- Long-lasting effects of current decisions about their use,
- Uncertainty of future demand conditions.

However, we will use a very simple approach, which is sufficient to demonstrate the basic principles of economics of exhaustible resources. Most of the issues listed above will be addressed in more detail in later chapters, as they are fairly relevant factors during the phase of project evaluation. With exhaustible resources, production of a unit today involves an opportunity cost: the forgone value of producing that unit at a later date. This opportunity cost must be taken into account in determining how to allocate the resource over time. In particular, instead of the usual efficiency condition (or competitive equilibrium condition),

**Price = Marginal Cost,**

we have

**Price = Marginal Cost + Opportunity Cost.**

The difference between the price and the marginal cost is also known as the user cost, or the royalty (or rent) (Hotelling rent). Therefore, the optimal depletion of exhaustible resources leads to a higher price and a lower level of production than competitive equilibrium would dictate for another commodity. The **Price = Marginal Cost** rule would lead to (P_e, Q_e) as equilibrium (see graph below). However, the opportunity cost of extracting a unit today, which is equal to the difference between points A and B (or P^+_e - P_e), raises the actual price to P^+ and lowers the actual output to Q^+.

---

**Opportunity Cost for an Exhaustible Resource**

![Graph](Image)

The behavior of this rent over time is important. After all, there will be a royalty tomorrow if the production of one barrel of oil is postponed until tomorrow. When is it, then, most beneficial for the producer to extract that barrel? To answer this question, let us work through a simple example. Suppose there are only 10 barrels of oil in the ground in total and that the marginal cost of production is constant at $2 per barrel. Also, assume that the demand in period t is given by the following equation: **P_t = 10 - Q_t.** Let us set the discount rate to 10%, r = 0.1. Finally, let us also assume, for simplicity, that the field will be exhausted after two periods. For an efficient outcome in each period, the objective is to maximize the net benefits, which is usually defined as the difference between what consumers are willing to pay and what it costs to produce. In Figure 1.1, this is the area below the Demand curve and above the Marginal Cost curve up to Q^*. Given a time horizon of two periods, the objective is to choose a level of production in each period in order to maximize the sum of the net benefits over two periods (naturally, the second period’s benefits are discounted to obtain a present value for them).

The constraint is that the total ultimate production is limited to 10 barrels. Without going into details, we can examine the simple results. Optimal levels of output for this problem turn out to be 5.14 barrels in the first period and 4.86 barrels in the second period. When we put these values into our demand function, we obtain $4.86 and $5.14 as the price of a barrel in the first and second periods, respectively. Given that marginal cost is $2 per barrel, the rent is equal to $2.86 in the first period and $3.14 in the second. Notice that, with discounting, $3.14 is equal to $2.86 (0.14(1.1)^2(1.1)^3(1.1)^4). This is an important result since it implies that the undiscounted rent must rise at the rate of interest. This is known as the r% (or Hotelling) rule. Note that even if the assumption of constant marginal cost is replaced by the more realistic assumption of increasing marginal cost, the rule still applies.

Unlike capital assets, like factory equipment, there are no dividends or depreciation for exhaustible resources and therefore the return must come entirely as a rise in the value of the asset. The value of exhaustible resources is the rent. Ideally, production is distributed over time in such a way that the rent rises at the rate of interest. This also implies that the price of a barrel of oil will increase continuously, because price equals marginal cost plus rent. However, this is not possible. In our simple example, the demand equation tells us that when the price reaches $10 a barrel, the quantity demanded will fall to 0. If price rises enough, people will have an incentive to develop substitute fuels or technologies which can replace oil. For example, renewable technologies, that are currently not commercially viable relative to oil, may replace oil as a source of energy if the price of the latter reaches a level where it would be economically feasible to switch to renewables from oil. Accordingly, the r% rule also implies a decreasing output over time. Of course, demand for oil and gas may rise over time, technological improvements may increase productivity or lead to additions to existing reserves and some other factors may impact the smooth pattern of extraction depicted in our figure. The r% rule itself is not sacred. If one allows for decreasing quality of oil extracted, for example, the rent will increase at a rate less than the interest rate. However, this only affects the degree of extraction and therefore the time horizon over which the resource will be exhausted, but not the downward trend of output.
Historically, price and output of oil and gas have not followed the smooth patterns our model predicts. Instead, they have fluctuated. The assumptions of our simple model about fixed marginal cost and fixed known amount of resource can be changed. This would lead to less smooth patterns for the price and extraction; but, overall, price will rise and output will decline as exhaustion approaches. The world price of crude oil slightly declined from the early 1950s until the early 1970s, but has become quite volatile and unpredictable since then (see chart below). The discrepancy between forecasts (those of the U.S. Department of Energy are presented) and actual prices shows that it is very difficult to accurately predict future prices. As we addressed above, the historical data do not concur with the theory of exhaustible resources. This is partially due to some of the assumptions of the theory that are not consistent with the practice in the industry. Two of these assumptions are discussed further in the following section.

### Historical Price of Crude Oil and Price Forecasts

![Historical Price of Crude Oil and Price Forecasts chart](chart)


### OIL AND GAS RESERVE TERMINOLOGY

**Recoverable Resources**

(Society of Petroleum Engineers)

<table>
<thead>
<tr>
<th>Total Oil and Gas Resource</th>
<th>Discovered</th>
<th>Undiscovered</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nonrecoverable Resources</td>
<td>Recoverable Resources</td>
<td>Cumulative Production</td>
</tr>
<tr>
<td>Reserves</td>
<td>Proved Reserves</td>
<td>Unproved Reserves</td>
</tr>
<tr>
<td></td>
<td>Probable Reserves</td>
<td>Possible Reserves</td>
</tr>
</tbody>
</table>

**Common Pool Problem**

The second flawed assumption in the economics of exhaustible resources is that free competition among producers lead to optimal rates of production. If a number of producers are extracting oil and gas from a common pool, they each have an incentive to extract as much as they can in order to maximize their revenue and profit. We call this a “common pool problem” and it exists for all natural resources, like timber, fisheries and non-fuel minerals. A solution is to establish rules that lead to more efficient resource extraction, what we typically refer to as “conservation practices.” The most important feature of conservation practices is shared information among producers and a third party, usually the government. There are many examples of the common pool problem for oil and gas, but perhaps the most famous is the situation in Texas at the turn of the century, when the giant East Texas and Yates fields were discovered. Intense competition among producers resulted in waste and reservoir damage, and caused the price of oil to collapse. The Texas Railroad Commission was given the authority in 1928 to regulate oil and gas production and, through its conservation practices, effectively controlled the world price of oil until OPEC’s first embargo in 1973.

A more recent example is the dispute between Qatar and Iran over the gas in the Persian Gulf. Two countries differ significantly in their estimates of how much gas each side has. Qatar already started production from several offshore platforms near the Iranian border. Iran complainst that Qatar is producing from Iranian reservoirs. As a result, although the country does not need the output from this field, it decided to develop fields on its side of the border before Qatar extracts more than its “fair” share.

### Exploration and Production

As we have seen in the previous chapter, companies study in detail every single project before they actually go ahead with it. Net Present Value (NPV) and Internal Rate of Return (IRR) are two of the decision criteria employed by companies to evaluate different projects. Since there is considerable uncertainty about the future values of variables used in calculating these criteria, the evaluation process needs to include some kind of likelihood (or probability) analysis. Decision trees, sensitivity analysis and simulation (also known as Monte Carlo simulation) are some of the tools available to professionals. Decision trees and simulation involve assigning probabilities to different values of crucial variables of the model. In order to be able to do this, considerable amount of data is required. Sensitivity analysis, on the other hand, studies the effect of a change in one (or more) variables on the NPV or IRR of the project. For example, managers may want to know how the NPV of the project would change if the price is 10% less than what was initially assumed.

Petroleum exploration and production (E&P) projects are fairly complicated as they contain several stages each containing quite a few
crucial variables. From the beginning, the inability to determine with certainty the geological characteristics of a project area indicates the necessity of probability analysis. Political factors, although not always built into calculations, also affect the outcome. In order to predict future values of crucial variables as accurately as possible, a considerable amount of data needs to be collected and analyzed. In the following sections, we will discuss these aspects of E&P in more detail.

Geological Characteristics

Petroleum is formed under the earth’s crust after the hydrocarbon-bearing matter, coming mostly from marine organisms deposited in marine sediments, has been exposed to high temperatures over a long period of time. Heat and pressure cause complex kerogen molecules to break down into simpler hydrocarbon molecules. This is known as the thermal cracking process. When “synthetic” oil and gas are manufactured from coal and oil shale, we are simply completing a process of nature, for coal and oil shale have not been burned deep enough or long enough for oil and gas to form. Petroleum can be produced only from rock formations that possess “porous” void spaces in the rock and can only move through these rocks by possessing some “permeability,” passages connecting the pores. Both are needed for oil to migrate and then be recovered from its trap when found. There are different kinds of traps where oil and gas can be found. Some are easier to detect by geological studies than others.

Water occupies some of total pore space in a rock formation. The fraction of water is called “water saturation.” The higher the level of water saturation, the lower will be the amount of oil and gas that can be extracted as water will move up the well bore, along with oil and gas. In the beginning, the amount of water extracted may be low, but as production continues, the water saturation in the reservoir will increase as fast as the amount of water extracted. Naturally, this will reduce the value of production as the same effort and expense provides less oil and more water.

All of these geological aspects of oil have some bearing on exploration and production operations since they help determine the amount of oil and gas that occurs and that can be produced. Eventually, geological factors impact the question of commerciality of a project. Developing technology, geophysical, geographical and topographical studies cannot provide anything better than an estimate of the size of the reservoir or production conditions. This uncertainty creates the risk a company needs to evaluate before it starts the exploratory drilling.

Economic Factors

Exploration is a time intensive activity and the rewards cannot be reaped until geological studies are completed and exploratory wells determine the existence of commercial quantities of oil. This situation is a problem of time inconsistency, when initial estimates of crucial variables diverge from actual values when the project is completed. A prime example is the price of oil. Uncertainty about the price of oil has been a fact of life since the turbulent 1970s. The estimate used in the beginning to evaluate a project may be much different than the actual value at the end. Similarly, operating costs may turn out higher than initially estimated.

Economic conditions in the country where a project is going to take place are also relevant. The uncertainty about the rate of inflation and tax rates, among other things, creates potentially dangerous situations for international investors. Some of these factors are complicated even further by the political situation in the host country.

Political Aspects

The major energy companies have always been involved in exploration and production projects all over the world. The political and legal environment of the country where a project is to take place has significant bearing on the cash flow analysis of the project as it affects the returns to the company through taxes, royalties, production sharing agreements, and so on. When evaluating a capital expenditure to be made in another country, the parent firm must be concerned with the cash flows that can be expected to be received by the parent and not the overseas subsidiary as the host country may block the subsidiary from remitting funds back to the parent (repatriation). It is also possible that the host government can take the parent’s assets in the subsidiary with inadequate or no compensation. Exorbitant exchange rates between the country’s currency and that of the parent company can create risk as well. A host country’s geographic location and its relationship with its neighbors are also important as these may impact solutions to the problem of getting oil/gas to the market from the producing field.

Most of the time, companies operational in different countries diversify their risks, in much the same way as individuals manage their investment portfolios; by mixing low risk projects with high risk but high return prospects of different parts of the world. Politically, internationally, internationally, international operations can play a role as well. After the Gulf Crisis in 1990-91, Iraq was banned from selling oil and foreign companies were not allowed to invest in Iraq due to U.N. sanctions. Also, the U.S. sanctions on countries such as Libya and Iraq prevent U.S. companies from investing in these countries. Conoco, Chevron, Amoco and others invested considerable sums in countries where later restrictions prevented them from operating. These examples show that international operations as well as countries of origin may present issues to consider for companies during project evaluation.

Technical Aspects of E&P Operations

Exploration is the riskiest undertaking of the oil and gas business, as it requires large amounts of capital investment before the existence, volume and quality of hydrocarbons are known. The quality of oil and gas, once found, may be lower than expected. For example, oil and gas may contain high proportions of sulfur and other contaminants, requiring expensive cleaning processes. In some cases, these contaminants may be valuable after cleaning, making them more valuable than they were before. For example, a heavier crude oil may be more valuable than a lighter crude oil, if it can be cleaned properly. Similarly, the decision to invest in a high-probability oil field may be influenced by the potential for high returns, even if everything else goes as expected. In order to get a better understanding of what is involved in E&P operations and sources of risk, let us take a closer look at the costs involved. Exploration costs include the following:

- Topographical, geographical and geophysical (G&G) studies, rights of access to properties - to conduct these studies and G&G studies locate an area under which significant amounts of oil and gas may be trapped. Then, the first exploratory well needs to be drilled in order to actually establish the existence and size of the reservoir. The first well provides additional data on:
  - Initial reservoir pressure and temperature,
  - Formation properties,
  - Fluid properties,
  - Short-term flow tests to estimate the potential rate and reservoir extent,
  - Geophysical sample data and depth reference points for modification of pre-drilling data.

Despite all these data and analysis, a reserve number is just an estimate, not an absolute quantity. And once production starts, reservoir conditions may change and production rates may fall. There are natural factors that help push oil and gas out of the well bores.

- If the pressure in the formation is higher than the pressure in the well, it will push the oil and gas up the well bores.
- An aquifer, which expands in size as production continues, will act as a piston and push the fluids up.
- A gas cap, which expands as production continues can push the oil out of the pores toward the well. If the reservoir has enough vertical permeability, gas rises and oil falls because of density differences. This separation of oil and gas enhances oil recovery.

On the other hand, there are some natural forces that resist the upward flow of oil.

- Significant capillary forces in tight sections of the formation, where permeability and porosity are low, reduce the flow of oil and gas.
- Low permeability and porosity mean that the rock is tight and cannot produce at commercial rates.
- Limitedness of the area of flow around the well bore can also lower the rate of production. The thicker the producing strata, the greater the rate of extraction, and vice versa.
- If oil is high in viscosity, it will not flow as easily.
- The farther oil needs to flow to reach the well, that is, the deeper the objective, the greater will the resistance to flow.

If the resistance to flow overwhelms natural driving forces or production declines rapidly after completion due to certain unfavorable formation conditions, some techniques to enhance oil and gas recovery may be needed. A few examples are listed below:

- Water flooding is sometimes used to increase pressure, in a process called “secondary recovery.” This involves injecting of water under pressure to push oil to the producing wells. Sometimes chemical solutions (detergents), carbon dioxide or other substances may be used, in a process called “tertiary recovery.”
- Associated gas produced along with oil may be reinjected into the reservoir to push oil reserves up.
- When oil is high in viscosity, a steam flood may reduce viscosity and hence increase the rate of flow.
- Part of the oil can be burned in the reservoir to increase porosity and help produce rest of oil.
- Gas often occurs in low quality reservoirs. “Nonconventional gas” produced from coal (coalbed methane) and shales is called “tight gas.” This gas requires that the formation be fractured. “Fracing” involves pumping fluids into the producing zones under extremely high pressures in order to increase, widen and connect the naturally occurring fracture system.

There are other options as well. However, all are fairly expensive. The decision to employ these methods depends on the expected increase in
E&P projects are expensive in that they require large sums of initial investment. Many companies and host countries are not able or willing to meet these requirements. On the other hand, international capital markets are becoming more and more competitive as emerging economies need more capital to finance their economic development. Therefore, both companies and host governments need to deal with the lenders who usually prefer lower risk projects. With the level of competition for funds that exists today, lenders have the luxury of being selective.

Models of E&P Investment
The table at the end of the chapter represents cash flow calculations used in evaluating E&P projects for a typical production sharing contract (PSC). It does not include everything discussed in the previous section, but the most crucial variables such as reserve size, bonuses, royalty share, and so on are analyzed (see appendix for this chapter for details on petroleum fiscal systems). Natural price of oil is also considered as one of the most volatile and significant variables for oil projects. Two decision criteria, net present value (NPV) of cash flows (at different discount rates) and the corresponding internal rate of return (IRR) as introduced in Chapter 3, are also presented. In our example, annual cash flow is calculated as follows:


Where

Net Revenues = Gross Revenues – Royalties – Price x Production – Royalty Rate x Gross Revenues

Tangible Expenses are based on the costs associated with exploratory and development wells and other infrastructure that needs to be developed before production can start. Exploration usually takes place first. So, in this example, we have $5 million in Year 1 for G&G expenditures, $25 million for two exploratory wells in Year 2, $125 million in Year 3 for development drilling, and $160 million in Year 4 to complete the infrastructure in the production site.

Intangible Expenses are calculated as a portion of Tangible Expenses but are non-depreciable. Usually, these costs are rolled in Tangible Expenses with PSCs as part of the cost recovery process.

O&M Expenses are simply calculated as the product of oil production times O&M cost per barrel (usually an estimated based on the data package on the field, G&G analysis and information about historical cost in the same region).

Bonuses are usually paid at contract signing or when the production starts or at both times. Note that if the field was acquired after an auction round, the bid paid as a result of the auction would also have to be considered as an upfront cost similar to bonuses.

Total Profit Oil = Net Revenues – Cost Oil if this difference is positive, otherwise 0. Cost Oil is the portion of costs that the contractor is allowed to recover under the terms of the PSC contract. For this calculation, costs = Intangible Expenses + O&M Expenses + DDA (Depletion, Depreciation & Amortization). As long as these costs are depreciable, the cost recovery amount (cost recovery percent agreed in the PSC x Gross Revenues), they can all be considered in Total Profit Oil calculation as Cost Oil.

Contractor’s Profit Oil = Total Profit Oil x Contractor’s Profit Share

Income Tax is basically equal to the taxes paid out of Contractor’s Profit Oil based on the tax rate. Tax Loss Carry Forward is used to account for tax reimbursements for taxes paid before production and, hence, revenues start.

Some of the key input variables that are usually set during the bidding stage or through negotiations with the government entities are provided in the table below. Production profile is consistent with estimated reserves of 319 million barrels for a 30-year project. O&M cost per barrel, cost recovery limit (usually between 80% and 100%), contractor profit share, income tax, royalty rate and bonuses that are used in above cash flow calculations are provided as inputs in this table. In addition, price is set as $25 per barrel. Our calculations show that, over 30 years, this project yields an NPV of $596 million at a 10% discount rate with an IRR of 32%. At 15% discount rate, the NPV goes down to $317 million. The project looks good under these criteria.

There are two other criteria that are used to assess upstream projects: present worth payout (PWP) and present worth index (PWI). PWP is the time it takes to recover an investment in terms of present value dollars. It represents the elapsed time (expressed in years) that it takes for the present value of the net cash inflows to equal the present value of the net cash outflows. It is measured from the initial outflow of funds. PWI is the ratio of the present value of cash inflows to the present value of the cash outflows. PWI measures the relative attractiveness of projects per dollar of investment. For the project reviewed in this section, PWP is equal to 7.3 years and PWI is equal to 3.33 (see cash flow table at the end of the chapter for calculating). The project promises to allow recovery of upfront investment in about 7 years with overall inflows more than three times the initial outflows. A comparison of these four evaluation criteria follows.

Production path and annual cash flow for the lifetime of the project are depicted below. Note that production stops from the fifth year until the fifth year of the project (including Year 0 when signing bonus was paid). During the first four years, the contractor invests heavily in G&G analysis, drilling exploratory and development wells and, if the field is promising, the development of the rest of the production infrastructure. Also note that production peaks fairly rapidly in the first few years of production, reaching a plateau that is sustained for several years and then follows a smooth decline curve. In the absence of reserve additions, this is one of the results of the exhaustible resource model. Upstream operations after reaching the plateau are very much directed towards sustaining higher levels of output and restraining the pace of the decline. Naturally, cash flows reflect the upfront investment requirements (significant cash outflows in first 4-5 years and follow a pattern almost identical to that of
For this project, NPV is greater than 0 and IRR is greater than 10%, supporting a “go” decision on the project. PWP and FWI also indicate a “go” decision. But, this single observation cannot be taken as granted since our assumptions about certain variables may not hold in the future, impacting the projected cash flows. Usually, decision makers would like to learn about different scenarios. For example, they may be interested in following scenarios:

- What if the price of oil is $20 instead of $25? New NPV = $421 million and new IRR = 27%. Note that the price of oil is not a baseline variable implying average price assumption can be very misleading. For example, if the price of oil collapses when the field’s production is peaking, the project will definitely feel the damage. The longer the price stays low in this period, the worse it will be for the contractor. See an example of price fluctuations below.
- What if O&M costs per barrel doubles to $4? New NPV = $516 million and new IRR = 30%.
- What if only 150 million barrels could be recovered from the reserves? New NPV = $405 million and new IRR = 31%. Note that, in this case, the contractor can also make adjustments to number of wells drilled to either extend the life of the reserves or quickly produce and recover its costs.
- What if the contractor was awarded this field as a result of an auction following a $100 million bid? New NPV = $496 million and new IRR = 23%.
- What if all of these four conditions occur for the project? New NPV = $111 million and new IRR = 14%. Although still a positively assessed opportunity, the project looks much less attractive.

Naturally, there are many other things that can go wrong, as discussed earlier in this chapter, including some non-economic factors. Many are not reflected in our simple model. But, even with more variables, this type of sensitivity analysis, although useful, does not cover all possibilities with enough scrutiny.

A more sophisticated approach called simulation analysis (Monte Carlo simulation) is more widely used. Computers have made it both feasible and relatively inexpensive to apply simulation techniques to capital budgeting decisions. The simulation approach generally is more appropriate for analyzing larger projects. A simulation is a financial planning tool that models some event. When simulation is used in capital budgeting, it requires that estimates be based on the probability distribution of each cash flow element (reserves, price of oil, O&M costs, and so on). These probability distributions then are entered into the simulation model to compute the project’s net present value probability distribution.

The simulation approach is a powerful one because it explicitly recognizes all of the interactions among the variables that influence a project’s net present value. It provides both a mean net present value and a standard deviation that can help the decision maker to make trade-offs between risk and expected return. Unfortunately, it can take considerable time and effort to gather the historical data necessary for each of the input variables and to correctly formulate the probability distributions. Also, crucial variables such as the price of crude oil have been very volatile and cannot be easily represented by normal, bell-shaped probability distributions. This limits the feasibility of simulation to very large projects. In addition, the scenario examples illustrated above assume that the values of the input variables are independent of one another. If this is not true, then this interaction must be incorporated into the Monte Carlo model, introducing even more complexity.

### Oil Price Shocks

Finally, we analyze the effects of price shocks on the returns of the project. We consider two very simple scenarios of identical price shocks but with different timing. For the first scenario, we assume that the price of crude oil falls to $10 per barrel from $25 per barrel during the second year of production, and stays at that level for five years before rising to first $15 for four years, then to $20 for four years and then to $25. Despite subsequent increases, the crash in oil prices causes the project NPV to fall to $230 million from $596 million. Accordingly, the project IRR is now 19% as opposed to 32% we obtained from our original model.

For the second scenario, we push the same price cycle to five years later. Although lower than original, the NPV is now $406 million and the IRR is 29%. The same price shocks coming five years later in the life of this project makes a significant difference. The following chart shows the fluctuations in the cash flow of the project that are due to price shocks under the two scenarios. Clearly, in the first scenario, the contractor can postpone some of the production anticipating the eventual rise of the price again (historically this has been the case; besides OPEC can always play a role if price is too low), but this will probably be costly. In addition, the contractor may be bound contractually to sustain production at certain level. Nevertheless, it is also clear that the first scenario can be detrimental for many projects.

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**Relevant Case Studies:**
- Apertura in Venezuela
- Brazil’s Restructuring of the Oil & Gas Industry Chad Cameroon Pipeline
- Deepwater Developments in Angola Deepwater Developments in Brazil Energy Inc. Deepwater Project North Atlantic Canada
- Oil Monetization in Azerbaijan
- Soviet Legacy on Russian Petroleum Industry

**APPENDIX**

**Fiscal Terms for Upstream Projects – An Overview**

Fiscal terms for upstream investment refer to the agreement between a local government and an oil and gas exploration company to explore, develop and produce hydrocarbons. The objective of a host government is to maximize wealth from its natural resources by encouraging appropriate levels of exploration and development activity. In order to accomplish this, governments must design fiscal systems. The objectives of the oil companies are to build equity and maximize wealth by finding and producing oil and gas reserves at the lowest possible cost and highest possible profit margin.

In a competitive world, areas with the least favorable geology, the highest costs, and the lowest prices at the wellhead would offer the best fiscal terms, while areas with the best geology, the lowest costs, and the highest prices at the wellhead would offer the toughest fiscal terms. The objective of the host government is to design a fiscal system where exploration and development rights are acquired by those companies who place the highest value on these rights. In an efficient market, competitive bidding can help achieve this objective. The hallmark of an efficient market is availability of information. Yet exploration is dominated by numerous unknowns and uncertainty. With sufficient competition the industry will help determine what the market can bear, and profit will be allocated accordingly. In the absence of competition, efficiency must be designed into the fiscal terms. This is not easy to do.

**Introduction**

Regardless of what fiscal system is used, the bottom line is the financial issue of how costs are recovered and profits divided. In order to accomplish this, governments must design fiscal systems that:
- Provide a fair return to the state and to the industry.
- Avoid undue speculation.
- Limit undue administrative burden.
- Provide flexibility.
- Create healthy competition and market efficiency.

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**Masterbook of Business and Industry (MBI)**

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Muhammad Firman (University of Indonesia - Accounting)
The design of an efficient fiscal system must take into consideration the political and geological risks as well as the potential rewards. Detailed economic modeling using cash flow analysis is the best way to evaluate division of profits. Factors that limit a company’s profits in a contract, such as cost recovery allowance, a government’s right to back-in for an extra share of production, or an additional tax, can be modeled for the purposes of contract negotiation or project evaluation. Division of profits is commonly referred as contractor take and government take.

### Concessionary Systems

Concessionary systems are divided into service contracts and production sharing contracts. (PSC) or a service contract.

- **Royalty:** Royalties are the first deduction.
- **Cost Recovery:** Before sharing of production, the contractor is allowed to recover costs out of net revenues. Most PSCs place a limit on cost recovery. If operating costs and DD&A amounts to more than the allowed limit, the balance would be carried forward and recovered later. From the mechanical point of view, the cost recovery limit is the only true distinction between concessionary systems and PSCs.
- **Profit Oil Split:** Revenues remaining after royalty and cost recovery are referred to as profit oil or profit gas. The analog in a concessionary system would be taxable income. The contractor share of profit oil or gas is a specified percentage. If this were a service agreement, the contractor’s share would be called service fee.
- **Taxes:** The contractor's share of profit oil and gas is subject to taxation. The title of the hydrocarbons remains with the state.
- The State maintains management control and the contractor is responsible for the execution of petroleum operations in accordance to the terms of the contract.
- The contractor is required to submit annual work programs and budgets for scrutiny and approval the State Company.
- The contract is based on production sharing and not profit-sharing basis.
- The contractor provides all financing and technology required for the operations and bore the risks.
- During the term of the contract, after allowance for up to a specified percentage of annual production for recovery of costs, the remaining production is split between the contractor and State.
- Equipment purchased and imported by the contractor become property of the State. Service company equipment and leased equipment are exempt.

### Production Sharing Contracts

In most contractual systems, the facilities put in place by the contractor within the host government domain become the property of the state either the moment they are landed in the country or upon startup or commissioning. Sometimes, the title to the assets or facilities does not pass to the government until the attendant costs have been recovered. Contractual systems are divided into service contracts and production sharing contracts. The difference between them depends on whether or not the contractor receives compensation in cash or in kind (crude). The distribution of how gross revenues are distributed from a barrel of oil under a PSC.

### Basic Elements

The basic elements of a production sharing system are categorized in the following table. These elements are also found in concessionary systems with the exception of the cost recovery limit and production sharing. Many aspects of the government/contractor relationship may be renegotiated but some elements are determined by legislation. Those elements not determined by legislation must be negotiated. Usually, it is better to have more aspects that are subject to negotiation. This is true for the government agency responsible for negotiations as well as for the oil companies. Flexibility is required to offset differences between basins, regions, and license areas within a country.

### Production Sharing Fiscal/Contractual Structure

#### Operational Aspects

- Government participation
- Ownership transfer
- Arbitration
- Insurance

#### Revenue or Production Sharing Elements

- Royalties
- Taxation
- Depreciation rates
- Investment credits
- Domestic obligation
- Ringfencing

#### Work Commitment

The work commitment refers to the obligations an exploration company incurs once a PSC is formalized. Work commitments are generally measured in kilometers of seismic data and the number of wells to be drilled in the exploration phase.
Bonuses and Royalties

Cash bonuses are lump sums paid by the contractor to acquire a particular license. These cash bonuses are the main element in bidding rounds of very prospective acreage. Production bonuses are paid when production from a given contract area or field reaches a specified level.

Royalties

Royalties are taken right off the gross revenues. Royalties range as high as 15%, although many PSCs do not have a royalty. A specific rate royalty is relatively rare, but it may also go by another name, such as "export tariff," like in the former Soviet Union or the War Tax levy in Colombia.

Another aspect of royalties that contributes to their lack of popularity with the industry is that they cause production to become uneconomic prematurely. This works to the disadvantage of both the industry and government. One remedy that has become popular is to scale royalties and other fiscal elements to accommodate marginal situations. Sliding Scales. A feature found in many petroleum fiscal systems is the sliding scale used for royalties, taxes and various other items. The most common approach is an incremental sliding scale based on average daily production. A sample sliding scale royalty is provided below.

Average Daily Production

<table>
<thead>
<tr>
<th>Average Daily Production</th>
<th>Up to 10,000 BOPD</th>
<th>10,001-20,000 BOPD</th>
<th>Above 20,000 BOPD</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost Recovery</td>
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</table>
| Cost recovery is the means by which the contractor recoups costs of exploration, development, and operations out of gross revenues. Most PSCs have a limit to the amount of revenues the contractor may claim for cost recovery but will allow unrecovered costs to be carried forward and recovered in succeeding years. Cost recovery limits or cost recovery ceilings, as they are also known, if they exist typically range from 30% to 60%.

Sometimes the hierarchy of cost recovery can make a difference in cash flow calculations. This is particularly the case if certain cost recovery items are taxable. Cost recovery of cost oil normally includes the following items listed in this order:

1. Unrecovered costs carried over from previous years.
2. Operating costs.
3. Expensed capital costs.
4. Current year DD&A.
5. Interest on financing (usually with limitations).
6. Investment credit (uplift).
7. Abandonment cost recovery fund.

In most respects, cost recovery is similar to deductions in calculating taxable income under a concessionary system. There are some exceptions. For example, some PSCs have no limit to cost recovery and some have no cost recovery.

Tangible vs Intangible Capital Costs.

Sometimes a distinction is made between depreciation of fixed capital assets and amortization of intangible capital costs. Under some concession agreements, intangible exploration and development costs are not amortized. They are expensed in the year they are incurred and treated as ordinary operating expenses. Those rare cases where intangible capital costs are written off immediately can be an important financial incentive. Most systems will force intangible systems to be amortized. Therefore, recovery of these costs takes longer, with more revenues subject to taxation in the early stages of production.

Interest Cost Recovery.

Sometimes interest expense is allowed as a deduction. Some systems limit the amount of interest expense by using a theoretical capitalization structure such as a maximum 70% debt.

General and Administrative Costs.

Many systems allow the contractor to recover some office administrative and overhead expenses. Non operators are normally not allowed to recover such costs.

Unrecovered Costs Carried Forward.

Most unrecovered costs are carried forward and are available for recovery in subsequent periods. The same is true for unused deductions. The term "sunk cost" is applied to past costs that have not been recovered. There are four classes of sunk cost: tax loss carry forward, unrecovered depreciation balance, unrecovered amortization balance and cost recovery carry forward. These items are typically held in abeyance (inactive) prior to the beginning of production. Many PSCs do not allow pre-production costs to begin depreciation or amortization prior to the beginning of production.

Exploration sunk costs can have a significant impact on field development economics and can strongly affect the development decision. The importance of sunk costs and development feasibility centers on an important concept called "commerciality." The financial impact of a sunk cost position on the development position can be easily determined with discounted cash flow analysis. The field development cash flow projection should be run once with sunk costs and one without.

Abandonment Costs.

Under most PSCs the contractor cedes ownership rights to the government for equipment, platforms, pipelines and facilities upon relinquishment or at abandonment. The government as owner is theoretically responsible for the cost of abandonment. Anticipated cost of abandonment is accumulated through a sinking fund that matures at the time of abandonment. The costs are recovered prior to abandonment so that funds are available when needed.

Profit Oil Split Taxation.

Profit oil and gas is split between the contractor and the government, according to the terms of the PSC. Sometimes it is negotiable. The contractor's share is usually subject to taxation.

Commerciality.

Commerciality deals with who determines whether or not a discovery is economically feasible and should be developed. Some regimes allow the contractor to decide whether or not to commence development operations. Other systems have a commerciality requirement where the contractor has to prove that the development of a discovery is economically beneficial for both the contractor and the government. The benchmark for obtaining commercial status for a discovery cannot be developed unless it is granted commercial status by the host government. The grant of the commercial status marks the end of the exploration phase and the beginning of the development phase of a contract.

Government Participation (Joint Ventures).

Many systems provide an option for the national oil company to participate in development projects. Under most government participation arrangements, the contractor bears the cost and risk of exploration. If there is a discovery, the government backs-in for a percentage, the government is carried through exploration. The key aspects of government participation are:

- What percentage participation? (most range from 10% to 51%)
- When does the government back-in? (usually once a discoveries made)
- How much participation in management? (large range of degree of participation)
- What costs will the government bear? (usually only their prorated share of development costs)
- How does government fund its portion of costs? (often out of production)

The financial effect of a government partner is similar to that of any working-interest partner with a few exceptions:

1. The government is usually carried through the exploration phase, and may or may not reimburse the contractor for past exploration costs.
2. The government's contribution to capital and operating costs is normally paid out of production.
3. The government is seldom a silent partner.

Contractors prefer no government participation. This stems from a desire for efficiency as well as economy. Joint operations of any sort, especially between diverse cultures, can have a negative impact on operational efficiency. This is particularly true when the interests of government and an oil company can be so polarized.

Investment Credits and Uplifts.

Uplift allows the contractor to recover an additional percentage of capital costs through cost recovery. For example, an uplift of 20% on capital expenditures of $100 million would allow the contractor to recover $120 million. Uplifts can create incentives for the industry. Uplifts are the key of rate of return contracts.

Domestic Obligation.

Many contracts specify that a certain percentage of the contractor's profit oil will be sold to the government. The sales price to the government is usually at a discount to world prices.

Ring fencing.

Ordinarily all costs associated with a given block or license must be recovered from revenues generated within that block. The block is ring fenced. This element of a system can have a huge impact on the recovery cost of exploration and development. From the government's point of view, any consideration for costs to cross a ring fence means that the government may in effect subsidize unsuccessful operations. However, allowing exploration costs to cross the fence can be a very strong financial incentive for the industry.

Reinvestment Obligations.

Some contracts require the contractor to set aside a specified percentage of income for further exploratory work within the license.

Tax and Royalty Holidays.

The purpose of tax and royalty holidays is to attract additional investment.

Risk Service Contracts.

In service contracts the contractor provides all capital associated with exploration and development of petroleum resources. In return, if exploration efforts are successful, the government allows the contractor to recover costs through sale of the oil or gas and pays the contractor a fee based on a percentage of the remaining revenues. The fee is often subject to taxes. The net importing countries are the ones most likely to use this approach. The distinction between PSCs and risk service contracts is
minute. The nature of the payment of the contractor’s services is the point of distinction.

Rate of Return Contracts

Contracts with flexible terms are becoming standard. There are advantages for both the host government and the contractor with contracts that encompass a range of economic conditions. The most common method used for creating a flexible system is with sliding scale terms. Most sliding-scale systems trigger on production rates. As production rates increase, the government take increases. This theoretically allows equitable terms for development of both large and small fields. Some contracts will provide flexibility through a progressive tax rate, otherwise, the tax will be levied on a sliding scale such as cost recovery, profit oil split and royalty.

The most common contract terms subject to sliding scale are profit oil split, royalty and bonuses. Less common are cost recovery limits and taxes. The most common factors and conditions used to trigger sliding scales are production rates, water depth, cumulative production, oil prices, age or depth of the reservoir, onshore vs offshore, R factors and the remoteness of locations. Less common are oil vs gas, crude quality, time period (history), distance from shore and rate of return. The objective with sliding scale systems is to create an environment where the government take flexes upward as with increased profitability. The result of most fiscal structures is that project profitability is a function of government take. In general, it is better for both parties when government take is a function of profitability.

Some countries have developed progressive taxes or sharing arrangements based on project rate of return (ROR). The effective government take increases as the project ROR increases. In order to be truly progressive, the sliding scale taxes and other attempts at flexibility should be based on profitability, not production rates. Some contracts use what is called an R factor. The R factor = Accrued net earnings / Accrued total expenditures. R factors are used to deal with all variables that affect project economics. Contractor potential upside from price increase is diminished, but the downside is also protected.

Technical Assistance Contracts (TACs)

TACs are often referred to as rehabilitation, redevelopment or enhanced oil recovery projects. They are associated with existing fields of production and sometimes, but to a lesser extent, abandoned fields. The contractor takes over operations including equipment and personnel if applicable. The assistance that includes capital provided by the contractor is primarily based on special know-how such as steam or water flood expertise.

Fiscal Terms for Gas

Only a few nations specifically support gas development through fiscal system. However, most nations that provide support have seen a strong development of the natural gas sector. Since most gas projects will typically have a relatively low rate of return compared with oil, ROR-based scales typically favor gas development. The higher the ROR benchmark, the more gas is being favored. The same applies to contracts that have R-factor sliding scales being used in production sharing, royalties or taxes. R-factor scales help gas economics because gas requires more investment and results often in lower prices at the wellhead on an energy basis. This may lower R factors in contracts. Conditions that make use of uplifts or depletion allowances in calculations that apply to oil and gas usually also favor gas with a few percentage points government take (Van Meurs & Seck, 1997).

CHAPTER 10

PIPELINES

Crude oil and natural gas need to be transported from producing fields to refineries, and processing plants, and products need to be transported to the markets. Land and sea tankers along with pipelines have long served this purpose well for oil. Tankers are still quite indispensable as large volumes of oil need to be shipped long distances, for instance from the Persian Gulf to the U.S. or to Japan. Geographical and economic, sometimes combined with political, barriers do not allow pipeline construction in some cases. In other circumstances, however, pipelines offer a cheaper and efficient alternative to tankers in transporting oil. This is especially true in the case of natural gas which needs to be “liquefied” through an expensive process in order to be shipped in tankers and then “regasified” in order to be consumed by end-users in as flexible an end-use as possible. Gas. Accordingly, in most cases, pipelines are clearly the better choice for transporting natural gas.

In total, there were about 45,000 miles (72,450 km) of pipelines under consideration in 1996, 64% of which were gas pipelines. In 1999, only 20,000 miles (32,200 km) of pipelines were considered, but a greater percentage (81%) was intended to transport gas. Except these two extreme years, more than 30,000 miles of pipelines were considered in each of the other years for both crude oil and gas transportation.

In the period from 1996 to 1999, the decrease in oil and natural gas prices resulted in a decrease in production. This reduction in production created a dampening effect on pipeline construction plans, which reached its lowest in 1999 when the price of oil and natural gas dropped to an all time low. However, long-term, worldwide plans for oil and natural gas pipelines picked up again in 2000 mostly in response to unexpectedly strong prices since mid-1999.

Overall, natural gas pipelines dominated construction and engineering work in the late 1990s. Demand for gas is being driven mostly by growing worldwide demand for gas-fired electric power generation and to a lesser extent by growing industrial, commercial and residential demand. On the supply side, the need and desire to monetize stranded and flared gas assets are also supporting this trend. In 1996, more than 29,000 miles (46,690 km) of gas pipelines were under consideration, especially in Latin America and the

U.S. However, as prices dropped, some of the planned projects were reduced in size, postponed or cancelled. Prices bounced back in 2000, which is also witnessed by the increase in gas pipeline mileage to almost 25,000 miles (40,250 km) from 16,000 miles (25,760 km) in 1999. Most analysts expect prices to remain strong as the U.S. and global economy recover, profit oil split and royalty.

The following table illustrates the length of planned or under construction pipelines across different parts of the world. In 2001, about 18% of these pipelines were planned to be built in the Asia Pacific region and 18% in the FSU region. The U.S., with 19% of pipeline construction plans, continues to add significant miles to the world’s largest web of pipelines. Latin America accounts for about 12% of the total. Both Canada (9%) and Europe (9%) will construct about 3,000 miles of pipelines each, the former to ship its natural gas and mostly to the U.S. market, and the latter to meet its increasing demand for natural gas from diversified sources. The Middle East also accounts for 9% of the pipeline construction plans.

FSU’s shares in pipeline construction has increased significantly since 1996 from less than 1% to 18% in 2001, mostly at the expense of Latin America whose share declined from 26% in 1996 to 12% in 2001. Asia-Pacific also reduced the investment in pipelines, especially during the Asian crisis of 1998-99. Nevertheless, FSU seems to be the key region for expansion of pipeline capacity in the near future whereas Latin America appears saturated especially given current economic problems of the region.

In 2001, 65% of pipelines were intended for gas transportation, 23% for crude oil and the rest for products. Most regions, except for Africa where more than two-thirds of pipelines were for shipping crude oil, are expected to build gas pipelines. Clearly, crude oil pipelines have been a priority for Africa during the late 1990s. FSU and Latin America also intended to construct significant miles of crude oil and products pipelines. 45% of FSU pipelines were for crude oil, almost equivalent the share of gas.
pipelines. Note, however, that gas pipelines increased their share significantly only in 2000 and 2001. Asymmetrical, gas pipelines attracted most of the investment in Latin America in the late 1990s in addition to a fairly stable expansion of products lines in the range of 1,000 to 2,000 miles a year. For all other regions (including the Middle East), for the most part, there has been significantly more investment in gas pipelines than either in crude or products since 1996.

Africa

Operators in Africa are moving forward with plans to build long-distance pipelines designed to move oil and gas to distant markets. In 1997 and 1998 an increase in crude pipeline construction was observed, most of which was concentrated in Sudan and Zambia. About 2,000 miles of crude lines were under consideration in each year – 7% and 9% of total world crude oil pipelines, respectively. After a very inactive 1999, there is an increasing number of both oil and gas projects. The planned mileage for oil pipelines increased from 373 miles in 1999 to 1,738 miles in 2001 while 500 miles of gas pipeline were under consideration in 2000 and 2001 as compared to none in 1999.

Most of the recent larger proposed or planned projects in Africa involve regional pipelines, designed to deliver gas or crude to African or European markets. Some of the more notable projects include the $510-million, 620-mile, 24-inch West African Gas Pipeline project, designed to move Nigerian natural gas to markets in Benin, Togo and Ghana. In February 2000, the four nations signed an Inter-Governmental Agreement (IGA) which established the framework for realizing the project. The project has received administrative support from the Economic Community of West African States Secretariat and technical assistance from the U.S. Agency for International Development. The project is being developed by a consortium of Chevron, Shell, Nigerian National Petroleum Corp., Volta River Authority, Societe Beninoise de Gaz (SoBeGaz) and Societe Togolaise de Gaz (SoToGaz).

Work on the $3.5-billion Chad to Cameroon crude oil pipeline was scheduled to begin in October of 2001. The project involves building a 665-mile, 30-inch line to transport crude oil from the Doba fields in Chad to a terminal on the Cameroon Coast. The project is being developed by Exxon Mobil Corp., Petrons, and Chevron. A May 2003 completion is planned. The governments of South Africa and Mozambique have signed an agreement that facilitates construction of a $580-million pipeline. The project involves building a 400-mile, 26-inch line that will deliver gas from Mozambique’s Pande and Temase gas fields in northern Inhambane province to Ressano Garcia, and from there to Secunda in South Africa’s eastern Mpumalanga Province. There, it will serve as a feedstock to synthetic fuels and chemicals plants, as well as emerging South African gas distribution markets. A spur to Maputo may also be built. A joint-venture company owned by Sasol and the governments of Mozambique and South Africa is to build, own and operate the pipeline. A second- quarter 2004 completion is expected.

Asia-Pacific

Expected long-term economic growth in this geographically expansive region (China in particular) is boosting demand for some large pipeline projects, mostly for natural gas. Especially since 1998, almost all of the investment was directed towards gas pipelines. Continuing expansion of Australia’s gas transmission and distribution grid, extension of natural gas service to Tasmania and development initiatives to exploit gas reserves in Papua New Guinea as well as China’s increasing demand for gas are the reasons behind this trend. Although there has been significant activity in expanding the gas pipeline network in the region since 1996, averaging 3,600 miles a year between 1996 and 1999, a surge was observed in 2000 when almost 8,600 miles of gas pipelines (a 300% increase from 1999) were under consideration. In 2001, the trend continues with more than 4,200 miles of gas pipelines planned or under construction.

Canada

There has been considerable progress in recent years on gas interconnections between Canada and the U.S. Oil and products pipeline activity were relatively minor between 1999 and 2001 after averaging more than 1,100 miles a year between 1997 and 1998. Note, however, that gas pipelines represented more than 70% of pipeline activity in Canada except for 1998 when they accounted only for 56% of the total.

The Northern Border Pipeline, an extension of the Nova Pipeline, came on stream in late 1999 and connects to Chicago through the upper Midwest. The Maritimes and Northeast Pipeline came on stream in January 2000, running from Sable Island to New England. The Alliance Pipeline is a $2.5-billion, 1,875-mile pipeline, the longest ever built in North America, and is designed to carry about 1.3 billion cubic feet per day (bcf/d) of gas from western Canada to the Chicago area. The pipeline began commercial service on December 1, 2000. The Millennium Pipeline represents in the regulatory approval stage of development; it is slated to connect Canadian sources to southern New York and Pennsylvania. Crude oil pipeline construction in Canada is targeted to deliver oil to eastern provinces and to the U.S.

Europe

Europe’s gas pipeline construction projects have been and will continue to be consistently high as European countries increase their transmission and local distribution gas pipeline systems and replace old distribution systems with new lines to meet increasing demand for natural gas. Although the pace has slowed down from more than 3,000 miles a year during the period of 1996-1998, in 2001 there were almost 2,500 miles of gas pipelines under construction and/or planned. Even in 2000, more than 1,500 miles of gas lines were under consideration.

In 2000 and 2001, oil pipeline activity also picked up. The $1.13-billion, 563-mile oil pipeline to be built across the Balkans to connect the Black Sea to the Adriatic Sea is mainly responsible for this increase. As proposed, the line would run from the Bulgarian Black Sea port of Burgas, through Macedonia, to Albania’s Adriatic port of Vlorë. It is designed to provide a cheaper transportation alternative for oil coming from Russia, Azerbaijan, and Kazakhstan to markets in northwestern Europe and along the Adriatic Coast. A feasibility study has been completed. Original plans called for the project to have a four-year construction timeframe, and a 2005 completion. Construction was delayed due to the unrest along the route of the pipeline.

Former Soviet Union (FSU)

Russia’s new energy strategy, named “Energy Strategy to 2020,” emphasizes gas transportation as an area of concern. Due to a proposed increase in gas production in Eastern Siberia and the Far East, the strategy calls for a pipeline from Kovyktu to Irktusk, possibly continuing into China. Within two decades, the plan is to construct 16,800 miles of new lines and replace 14,300 miles of existing lines due to corrosion. In addition, the need of Caspian states such as Turkmenistan and Azerbaijan to export

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their gas caused an increased interest in gas export pipelines from the region. As a result, the mileage of gas pipeline under consideration jumped to 1,620 miles in 1999 and then to 3,634 miles in 2000 from almost none between 1996 and 1998. However, when the proposed Trans-Caspian gas pipeline from Turkmenistan to Turkey was removed from the proposed projects due to geopolitical reasons, the mileage fell to 2,611 in 2001.

FSU countries, especially in the Caspian region, also focused heavily on oil pipeline projects to gain access to the world market. In the late 1990s, regional pipelines were built including the one to connect Baku, Azerbaijan to Supsa, Georgia to start the early oil flow. In 2000, more projects (more than 1,000 miles) were under consideration and one large completed project was the construction of the 1,075-mile Baku-Ceyhan pipeline project, which will be the main export route for Azeri oil. The construction of this pipeline is connected to the Caspian Pipeline Consortium (CPC) pipeline that connects Kazakhstan’s Tengiz field to Russia’s Black Sea port of Novorossiyk is another project which has been successfully completed and is currently in use.

Latin America

There has been a constant decline in the mileage of pipelines that were under construction or planned since 1996, especially for natural gas. There were more than 8,000 miles of natural gas pipelines in the books in 1996 as compared to only about 1,400 miles in 2001. The decline has been continuous. On the other hand, there was a fairly stable interest in products lines, which averaged about 1,600 miles a year between 1996 and 2001. Recently, there is an increasing interest in crude oil pipelines, with more than 1,300 miles in 2001 as compared to only 200 in 1999. Nevertheless, the late 1990s were dominated by gas pipelines such as the 2,000-mile Bolivia to Brazil pipeline and others in Argentina and Mexico.

The gas pipeline construction numbers in 2001 consist of the 1,188-mile planned gas distribution projects in Brazil and the 135-mile gas transmission line from the U.S. to Mexico. As for crude oil pipeline projects, Mexico has just completed its 635-mile crude oil pipeline and the rest of the projects are proposed oil pipelines that include the 312-mile pipeline in Ecuador and the 207-mile planned pipeline in Brazil.

Currently, there are plans for expanding the gas transmission and distribution systems in Mexico in order to establish gas as a fuel of choice and help develop the country’s gas resources. At the same time, there are at least three projects that are aimed at delivering U.S. natural gas and related products to Mexican markets. Meanwhile, the governments of Mexico and Guatemala continue to study the feasibility of building a 347-mile pipeline to deliver Mexican natural gas to markets in Central America.

The development of the Camisea field in Peru is also expected to add several hundred miles of gas pipelines within the next few years.

The Middle East

As in other regions, except for 1996 natural gas pipelines constitute the bulk of projects in the Middle East region with Oman, Qatar, Saudi Arabia and the U.A.E. as the countries hosting most of the pipeline construction activity. In particular, there has been a significant increase in 2000 and 2001 in the mileage of gas pipelines under construction and/or that were announced. In each year, almost 2,300 miles of gas pipelines were under consideration as compared to an average of about 800 miles between 1996 and 1999. Since 1997, there has not been much interest in crude oil and products pipelines. In contrast, with almost 1,500 miles, products pipelines accounted for the largest share of investments in 1996. In 2000 and 2001, Qatar expanded its pipeline projects as it secured major contracts with neighboring countries such as the UAE, Bahrain and possibly Oman to supply natural gas to meet the needs of those countries.

Another line from the North field of Qatar to Pakistan is being promoted. The proposal envisions a 995-mile (1,601-km), 48-inch line to Pakistan.

The U.S.

During the past decade, interstate natural gas pipeline capacity has increased substantially. From January 1996 through August 1998 alone, at least 78 projects were completed adding approximately 11.7 bcf/d of capacity and much more will be needed in coming years. There has been constant investment in expanding the gas pipeline network in the U.S. at an average rate of almost 5,000 miles a year between 1996 and 2001, with a peak of 6,500 miles in 1997 and a trough of 3,722 miles in 1999. There has been an increase in gas pipeline projects to gain access to the world market. In the late 1990s, CVR countries, especially in the Caspian region, also focused heavily on oil pipeline projects to gain access to the world market. In the late 1990s, regional pipelines were built including the one to connect Baku, Azerbaijan to Supsa, Georgia to start the early oil flow. In 2000, more projects (more than 1,000 miles) were and other completed projects are the construction of the 1,075-mile Baku-Ceyhan pipeline project, which will be the main export route for Azeri oil. The construction of this pipeline is connected to the Caspian Pipeline Consortium (CPC) pipeline that connects Kazakhstan’s Tengiz field to Russia’s Black Sea port of Novorossiyk is another project which has been successfully completed and is currently in use.

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commonly available and reliable estimates, are provided in this section. Adjustments can be made for other countries mostly by considering differences in labor and material costs. In the U.S., there are approximately 152,005 miles of liquid pipelines. Largest 10 owners of pipeline mileage account for about 45% of the total. In 2000, total trunkline traffic of top 10 interstate oil pipeline companies was 2,114 billion barrels-miles for crude oil (60% of total traffic). These companies generated $1.3 billion in revenues (49% of total revenues).

Also, there are 237,079 miles of gas pipelines (194,673 miles of long distance transmission lines, 37,339 miles of field lines and 5,067 miles of storage lines). Largest 10 owners of pipeline mileage account for about 54% of the total. Although, offshore pipelines gradually increased transmission of other companies’ gas, acting like contract carriers. In 2000, pipeline companies moved nearly 32 trillion cubic feet (tcf) of other company’s gas and sold less than 800 bcf from lease lines to systems. Top 10 interstate gas pipeline companies moved about 16 tcf (49% of total volume) and generated $1.4 billion in net income (49% of total revenues).

Pipeline construction costs include several factors, the most important of which are material and labor costs which make up to 70% of the total construction cost both onshore and offshore. Surveying, engineering, supervision, administration and overhead, telecommunications equipment, freight, taxes, regulatory filing fees, interest, contingencies (all covered under Miscellaneous), right-of-way (R.O.W.) and damages make up the rest. The following two tables are based on a 1995-1996 survey of 62 land and 2 offshore projects and a 2000-2001 survey of 49 land and 2 offshore projects by the Oil & Gas Journal.

Total construction costs increased by 38% between 1995 and 2000 for onshore pipelines, mostly due to significant increases in labor and especially in miscellaneous items. The unavailability of experienced labor may help explain the increase in that category. Miscellaneous costs increased more than to an increase for specialized services such as surveying and engineering. Specialized service companies became able to ask for higher prices. The biggest variation (151%) was in the R.O.W. and Damages category. As longer pipes that extend across different boundaries and territories are being designed and built at increasing rates, governments saw an opportunity to benefit from these projects by charging pipeline companies different and higher fees. Material costs remained fairly constant.

<table>
<thead>
<tr>
<th>Estimated Pipeline Construction Costs per Mile and % of Total (Onshore)</th>
<th>1995-1996</th>
<th>2000-2001</th>
<th>% Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Material</td>
<td>$274,410 (33%)</td>
<td>$279,365 (21%)</td>
<td>2%</td>
</tr>
<tr>
<td>Labor</td>
<td>$427,610 (47%)</td>
<td>$717,179 (44%)</td>
<td>33%</td>
</tr>
<tr>
<td>Miscellaneous</td>
<td>$154,371 (17%)</td>
<td>$143,973 (26%)</td>
<td>12%</td>
</tr>
<tr>
<td>R.O.W. and Damages</td>
<td>$168,075 (55%)</td>
<td>$120,070 (9%)</td>
<td>151%</td>
</tr>
<tr>
<td>Total</td>
<td>$908,407</td>
<td>$1,316,164</td>
<td>38%</td>
</tr>
</tbody>
</table>

Source: Oil & Gas Journal, Pipeline Economics Survey, various issues.

Although there are only two offshore projects in both survey periods and hence the costs estimates may not be as robust, it clearly costs more to build pipelines offshore, especially due to increases in material and labor costs. As for the trends between 1995 and 2000, similar patterns are observed for offshore pipelines: overall costs increased by 60%, mostly due to increases in labor and miscellaneous items. Although there is a very significant increase in R.O.W. and Damages category, its share in total is still only 4%.

<table>
<thead>
<tr>
<th>Estimated Pipeline Construction Costs per Mile and % of Total (Offshore)</th>
<th>1995-1996</th>
<th>2000-2001</th>
<th>% Change</th>
</tr>
</thead>
<tbody>
<tr>
<td>Material</td>
<td>$684,604 (62%)</td>
<td>$413,991 (16%)</td>
<td>-40%</td>
</tr>
<tr>
<td>Labor</td>
<td>$527,610 (13%)</td>
<td>$1,537,249 (60%)</td>
<td>191%</td>
</tr>
<tr>
<td>Miscellaneous</td>
<td>$189,394 (15%)</td>
<td>$110,271 (20%)</td>
<td>29%</td>
</tr>
<tr>
<td>R.O.W. and Damages</td>
<td>$2,701 (10%)</td>
<td>$116,069 (4%)</td>
<td>3,552%</td>
</tr>
<tr>
<td>Total</td>
<td>$1,611,818</td>
<td>$2,578,413</td>
<td>60%</td>
</tr>
</tbody>
</table>

Source: Oil & Gas Journal, Pipeline Economics Survey, various issues.

Investors and project planners should consider the trends in the cost categories as guidelines whenever they try to estimate the cost of any pipeline project. The reason is that is as pipelines are being designed and constructed, the variation between actual incurred costs to the estimated costs widens. In order to accurately determine the financial value of any pipeline project, this variation should be quantified and minimized by a better prediction of the movement of each cost category and its relation with the number of projects being designed and built.

A Model of Pipeline Investment

We provide two examples of pipeline investment decision analysis, one for an oil pipeline and one for a gas pipeline. Cash flow calculations for a 42-inch, 800-mile oil pipeline are summarized at the end of the chapter. The model is set up to allow for project financing, with investors deciding on the debt-to-equity ratio. As a result, principal and interest service of the loan are included. Cash flow (the last column) is calculated as follows:


Where

Revenues = Sales x Tariff. Sales are based on the needs of the producing region and the consumption centers. The pipeline is assumed to reach contracted capacity in four years after the flow starts. Tariff is negotiated and basically determines whether the operator will invest in the pipeline or not.

Principle and Interest are calculated based on the loan structure (loan amount, interest rate, loan period) if a loan is taken. Equity loan ratio is an input. We also include an upfront fee for the loan and calculate interest cost during the construction period (i.e., before payments start along with revenues). O&M Cost is computed for you based on fixed and variable costs involved during operations and maintenance. For example, we use $23 million fixed and $2.3 per ton for this example (see table below).

We also allow for contingencies in O&M costs that may be associated with lack of skilled labor, poor infrastructure, bureaucratic changes and the like that commonly delay projects and increase costs, especially in emerging markets.

Transit Fees are paid if the pipeline passes through a third country and based on the transit fee that country charges (sales x tariff fee). The model allows for multiple transit countries.

Tax is calculated based on the taxable income, which is equal to revenues – depreciation - interest.

Input Data for the Oil Pipeline

Given the input values, this pipeline yields an NPV of $676 million and an IRR of 18%. It would be useful to analyze sensitivities of the project to some key variables. If the pipeline were not able to carry 20 million tons (MT) a year at its peak but only 18 MT, due to problems either at production end or consumption end or both, NPV would go down to $535 million and IRR to 16%.

If the loan rate was 18% instead of 15%, NPV would be $535 million and IRR would be 16%. The situation could be worsened if equity was not available and full cost would have to be met through financing at 18%. NPV would be further reduced to $325 million although IRR would remain at 14%. If the pipeline were to be rerouted in the middle of construction, due to environmental, social or historical reasons, an additional 50 miles may be needed. In that case, an NPV of $632 million and IRR of 17% would be obtained.

If all of these calamities occur at the same time, NPV would be $91 million and IRR would fall to 11%. There are other considerations such as the number of transit countries, transit fees to be negotiated with each, and fluctuations in O&M costs. But, the sensitivity analyses provided above should be sufficient to demonstrate risks associated with an oil pipeline.

A similar model of a gas pipeline is also provided at the end of the chapter. It is a 1,250-mile pipeline, using 42-inch pipes with three compressor stations. Cash flow is calculated using the same formula and definitions as the oil pipeline. The following table provides the input data. Note that the pipeline needs to go under water for about 10% of its length.

Input Data for the Gas Pipeline

Given the input values, this pipeline yields an NPV of roughly $724 million and an IRR of 15%. Again, it would be useful to analyze sensitivities of the project to some key variables. If the pipeline were not able to carry 15 billion cubic meters (bcm) a year at its peak but only 13 bcm, due to problems either at production end or...
Natural gas processing plants liquefy the heavier molecules that occur in the gas stream in order to make the production more marketable and to increase profits from the lease. Natural gas, produced from formations, differs from "town gas" which is manufactured from coal. This must be an important consideration in evaluating a processing plant is deciding which liquids to recover. Normally, natural gas consists of about 97% methane (one carbon and four hydrogen molecules), 1.5% ethane with the remainder formed by butanes, propane, and larger hydrocarbon molecules. “Wet” gas contains a higher proportion of larger molecules as well as oil condensate as opposed to “dry” gas, which contains little or none. Processing plant design is contingent on the composition of the gas stream. Recovery of all molecules is possible but raises both the initial cost of plant and operating costs considerably. The value of the liquids produced should be high enough to cover the costs. However, during the stage of evaluating the project it is difficult to get a reliable estimate of their value. Liquids prices have been volatile in the past and market conditions are in constant change. Another consideration is the location and the size of the plant to be built. A site near producing fields would lower the cost of transportation of natural gas, while a plant located near consumption centers would make it easier to market the products. The size depends on the volume of gas expected to be processed, which in turn depends on estimates of the field based on geological studies and exploratory drilling. If the actual production falls short of estimates, the company can end up with an oversized plant. Naturally, the initial investment on this plant would also turn out more than necessary lowering the cash flow of the operation. Some types of processing technology available are as follows:

- Mechanical Refrigeration System. This system recovers 30 to 50% of propane and 80 to 90% of butanes at -20 degrees Fahrenheit.
- Turbo Expander. These type of plants recover up to 99% of propanes and butanes at 50 to 90% of 99% ethane.
- Short-cycle Unit (LTX Expansion System). This is mainly used for lean gas systems and recovers 20% of butanes and 80% of gasolines.

The choice of plant technology depends on the mix of liquids desired as discussed above. However, the output of liquids changes according to market conditions. At any given time, the plant operator may only wish to recover certain liquids and not others. This type of flexibility is, however, expensive.

A Model of Natural Gas Processing Plant Investment

Our model is for a small plant with a processing capacity of 100 million cubic feet (mcf) a day and a 10-year life. We assume an initial investment of $10 million will be sufficient for this plant. We further assume following recovery rates: 94.5% methane, 5% of liquids without specifying which molecules, and 0.5% of loss (gas consumed in the process as fuel). Profit margins are set to 10 cents per cubic feet for gas and 20 cents per cubic feet for liquids. Under these assumptions, the project’s after-tax cash flows yield a net present value of $5.93 million with an internal rate of return of 24%.

If, for example, the plant is not able to receive 100 mcf a day to process but only 75 mcf, the profit falls to $2.73 million instead of the $5.93 million. This example shows the importance of location of the plant in terms of consistently having the necessary supplies in order to fully utilize the plant’s capacity. Product margins, as in the case of petroleum refineries, can also create significant risk. If the profit margin for gas falls to 7 cents per cubic feet from 10 cents as we initially assumed, the project NPV falls to $2.46 million, and the new IRR is 16%. If lower margins and lower sales occur at the same time, the NPV now barely stays positive at $130,000 and the IRR falls to 10%. These new values seriously question the viability of the project.

Further “what if?” scenarios can be considered, including fluctuations in the profit margins of liquids. However, these will be less important, because liquids account only for a small percentage of the output. Given the assumption that the plant is designed to yield specified percentages, significant fluctuations in shares of gas and liquids in total output are not expected. As we have discussed in previous chapters, a full scale simulation model will incorporate all this information.

A Model for Gas Processing Plant Investment

Natural gas provided 24% of the world average energy primary needs in 2004 and is expected to increase to 25% in 2030 (see chart below). 2 Consumption of natural gas continues to increase worldwide.

Masterbook of Business and Industry (MBI)

CHAPTER 11

NATURAL GAS PROCESSING

CHAPTER 12

LIQUEFIED NATURAL GAS

What is LNG?

Liquefied natural gas (LNG) is natural gas that has been cooled to the point that it condenses to a liquid, which occurs at a temperature of approximately -256°F (-161°C) and at atmospheric pressure. Liquefaction reduces the volume by approximately 600 times thus making it more economical to transport between continents in specially designed ocean vessels, whereas traditional pipeline transportation systems would be less economically attractive and could be technically or politically infeasible. Thus, LNG technology makes natural gas available throughout the world. LNG trade originally started in 1964 around the Atlantic Basin, the emphasis shifted to the Pacific when the American market failed to live up to expectations. Japan, and later other Far East countries, lacking indigenous energy resources and isolated from potential sources of pipeline gas, found LNG to be attractive and created rapidly growing markets.

Reduction of Gas Flaring

Of particular interest is the role that exporting gas in the form of LNG might play to help reduce natural gas flaring, for both environmental benefits and to capture this premium commodity. There are large reserves of natural gas in areas for which there is no significant market. Such hydrocarbon reserves are straddled in North Africa, West Africa, South America, Caribbean, the Middle East, Indonesia, Malaysia, Northwestern Australia and Alaska. Some of the gas that would otherwise be flared is instead converted to LNG. This reduces the environmental impact of continuous flaring of large quantities of natural gas. About 2.5 tcf of natural gas is flared annually out of a total of 112 tcf of gas produced but not marketed globally. The balance is re-injected into the reservoir due to lack of markets.

To end flaring is a goal for producing countries and companies, environmental groups and institutions, like the World Bank. These initiatives have contributed to increased interest in LNG as a means of utilizing valuable natural gas resources and contributing toward sustainable development.

Natural Gas Trends

Natural gas provided 24% of the world average energy primary needs in 2004 and is expected to increase to 25% in 2030 (see chart below).

Consumption of natural gas continues to increase worldwide...
This increasing demand is mainly due to the fact that natural gas is one of the cleaner and most efficient energy sources, especially when used in power generation. As a result, most of the increase in natural gas consumption has come from and is expected to come from the electric power sector. Market reforms in many countries have been fueling the development of merchant generation facilities. Although many of these investments failed to generate desired revenues and faced a variety of problems (e.g., failure to dispatch), natural gas remains the fuel of choice for large scale power generation.

Natural Gas Consumption by Country in 2004

The rate of increase is faster in the Asia Pacific Region than elsewhere, although relative consumption in this region still lags behind the traditional markets of Europe and North America. In 2004, the U.S., Russia, U.K., Germany, Canada and Japan made up about 52 percent of total worldwide natural gas consumption (see chart to the right). The largest increments in gas use are expected in Central and South America and in developing Asia, and the developing countries as a whole are expected to add a larger increment to gas use by 2030 than are the industrialized countries. The largest natural gas usage in 2030 are expected to still be North America (mostly the U.S.) and Western Europe and Russia.

The growth in demand for natural gas worldwide is outpacing the demand for any other hydrocarbon fuel. This is due to a number of factors, including price, environmentally benign characteristics of natural gas, fuel diversification needs of consumers, energy security concerns, deregulation of both natural gas and electricity markets, and overall economic growth. Accordingly, natural gas use is projected to double, to 147 trillion cubic feet (tcf) or 397 billion cubic feet (bcf/d) in 2025 from 96 tcf or 260 bcf/d in 2004 (see next chart).

Role of LNG in Global Natural Gas Trade

A global gas market has evolved to satisfy increasing demand for natural gas. Natural gas has been delivered from producing regions to consumption centers either by pipelines, or by ships in the form of liquefied natural gas, or LNG. In 2004, 26% of global natural gas was transported as LNG in specially designed tankers. The global LNG business and trade have grown at an average rate of 6% per annum between 1992 and 2002. 12 countries produced a total of around 6.6 tcf of LNG in 2004 to 14 importing countries. In February 2003, the Dominican Republic received its first shipment of LNG while in October 2003, Portugal’s new LNG terminal, Sines, processed its first cargo. India imported its first cargo of LNG in January 2004, while the UK joined the club of LNG importers in July 2005 when the Isle of Grain terminal was put in operation.

The growth in LNG demand has been particularly strong since the first cargoes were delivered in the 1964 from Algeria to the UK and France, and gas from Alaska to Japan. It expanded in the 1970s with shipments from Libya to Spain and Italy, from Algeria to the U.S., and most importantly, from Indonesia, Brunei and the Middle East to Japan. During the 1980s, LNG trade contracted along with a U.S. gas price collapse and expanded pipeline gas supplies in Europe. During the 1990s, while there was some growth in the U.S. and European LNG imports, imports to Japan and South Korea grew tremendously. Qatar became a significant supplier in the late 1990s. The worldwide LNG demand grew by about 5% in 2001, 2002 and 2004, and hefty 13% in 2003. The demand growth rate between 1992 and 2004 averaged about 6% per annum. This trend is expected to continue. According to the International Energy Agency (IEA), inter-regional LNG trade is expected to increase six fold, from 6.6 tcf in 2004 to about 25 tcf by 2030, becoming as important as pipeline trade by 2030.

The LNG trade can be conveniently divided into two regions the Pacific-Indian Basin and the Atlantic-Mediterranean Basin. Today, the Pacific Basin accounts for most of the LNG volumes traded, led by Japan and South Korea. However, most of the increase in LNG trade will be in the Atlantic basin, which is expected to overtake the Pacific basin in volume. European countries but increasingly the U.S. and Mexico are in need of LNG supplies. The 2004 global trade movement data are provided in the
appendix. Similar to the consumption picture, most of the LNG suppliers are located near and serve the Pacific Basin. Indonesia, Malaysia and Qatar are the largest suppliers in the region. The region is home to most of the 19 liquefaction facilities operating worldwide. Qatar LNG recently overtook the eight-train, 22-mtpa, (1.07 Tcf per year) Indonesian facility at Bontang on the eastern Kalimantan coast with a 25-mtpa facility as the largest in the world.

Algeria is the only supplier in the Atlantic Basin that is comparable in size. As of April 2004, there were 202 LNG carriers operating with another 148 under construction. Nearly all of these carriers are being built in Japan and South Korea, which together control over 70 percent of the market. But shipbuilders in China, France and Spain have orders for five, three and one ship respectively and could potentially emerge as serious competitors to Asian LNG shipbuilders. At the other end of the LNG chain are the regasification terminals, of which there are 49 operating worldwide. The largest of these is the Sodegaura terminal operated by Tokyo Gas, with a storage capacity of 2.66 million cubic meters (94 MMcft).

New LNG Supplies
A number of plants are currently being expanded, and many new LNG trains have been announced, mostly in the Atlantic Basin.

Atlantic Basin
In the Atlantic Basin, LNG is currently being produced by Algeria, Libya, Nigeria and Trinidad and Tobago. Egypt has recently put in operation two terminals in the Mediterranean with an associated overall liquefaction capacity of 400 bcf per year. All these countries have substantial expansion capacity, some of which is already in the planning process or committed. In addition, countries like, Angola and various others in West Africa have announced new projects. Although more expensive, some of the Middle East countries augment the LNG supply into the Atlantic Basin. The largest of these is the Sodegaura terminal operated by Tokyo Gas, with a storage capacity of 2.66 million cubic meters (94 MMcft).

Representative LNG costs are shown above. Variation in the cost for natural gas feedstock (production) hinges on terms that governments offer for E&P activity. Shipping costs will vary based upon shipping distance. Natural gas price forecast and cost of LNG (5/MMBtu)

The chart above compares the EIA forecast of natural gas in North America with the range of delivered cost of LNG. Clearly, LNG projects can be commercially viable and provide cost-competitive natural gas supplies to the U.S. market. It is also useful to keep in mind that the benchmark, Henry Hub natural gas price has been above $3.50 per MMBTU since early 2000 and with expectations going forward of prices above $4.00 for some time to come.

In recent years, competition among builders has been driving down costs for both green-field plants and vessels. Technology development and improvements in refrigeration and liquefaction techniques have reduced the capital costs of LNG processing and shipping, allowing more LNG projects to achieve commercial viability. The result has been a proliferation of LNG sales in both the Asian and Atlantic Basin markets. Today, LNG competes with pipeline gas in the North American and European markets and will soon compete in additional markets. The

<table>
<thead>
<tr>
<th>Atlantic Basin Suppliers</th>
<th>Size (mtpa)</th>
<th>Startup</th>
</tr>
</thead>
<tbody>
<tr>
<td>Algeria - Arzew, Raspol YPP/Gas</td>
<td>5.2</td>
<td>2009</td>
</tr>
<tr>
<td>Algeria - Skikda, Souartrach</td>
<td>4.5</td>
<td>2010</td>
</tr>
<tr>
<td>Angola - Soyo, Chevron/BP/EnocoMobil/Total</td>
<td>5.0</td>
<td>2006</td>
</tr>
<tr>
<td>Libya - Marsa Al-Brega expansion, BP</td>
<td>3.2</td>
<td>2008</td>
</tr>
<tr>
<td>Equatorial Guinea - Biko Island, Marathon Oil</td>
<td>3.4</td>
<td>2008</td>
</tr>
<tr>
<td>Nigeria - NLNG Plant</td>
<td>2.0</td>
<td>2007-10</td>
</tr>
<tr>
<td>Nigeria - Brunei LNG</td>
<td>2.0</td>
<td>2007-10</td>
</tr>
<tr>
<td>Nigeria - NNPC/ConocoPhilips/Cherono/ENI</td>
<td>10.0</td>
<td>2009</td>
</tr>
<tr>
<td>Nigeria - Okolada LNG, NNPC/BG/Cherovo/Shell</td>
<td>20.0</td>
<td>2010</td>
</tr>
<tr>
<td>Norway - Saltvet</td>
<td>4.0</td>
<td>2006</td>
</tr>
<tr>
<td>Trinidad 5-6</td>
<td>6.0</td>
<td>2009-10</td>
</tr>
<tr>
<td>Venezuela - Gea Marical de Ayacucho</td>
<td>4.7</td>
<td>2010</td>
</tr>
<tr>
<td>Venezuela - Jose</td>
<td>2.1</td>
<td>2007</td>
</tr>
<tr>
<td>Russia - Yamal Peninsula</td>
<td>7.5</td>
<td>2010</td>
</tr>
<tr>
<td>Total</td>
<td>95.0</td>
<td></td>
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</tbody>
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<table>
<thead>
<tr>
<th>Pacific Basin Suppliers</th>
<th>Size (mtpa)</th>
<th>Startup</th>
</tr>
</thead>
<tbody>
<tr>
<td>Australia - Gordon LNG, Cherovo/ExxonMobil/Shell</td>
<td>5.0</td>
<td>2009</td>
</tr>
<tr>
<td>Australia - Woodside Energy 5</td>
<td>4.2</td>
<td>2008</td>
</tr>
<tr>
<td>Russia - Sakhalin II</td>
<td>9.6</td>
<td>2008</td>
</tr>
<tr>
<td>Indonesia - Tangguh, BP</td>
<td>7.6</td>
<td>2008</td>
</tr>
<tr>
<td>Qatar - Qatargas 2-4</td>
<td>31.2</td>
<td>2008-09</td>
</tr>
<tr>
<td>Qatar - RasGas 2-3</td>
<td>12.5</td>
<td>2007-08</td>
</tr>
<tr>
<td>Peru - Pampa Melchorita</td>
<td>4.4</td>
<td>2009</td>
</tr>
<tr>
<td>Yemen - Ball Halil Total</td>
<td>6.2</td>
<td>2009</td>
</tr>
<tr>
<td>Total</td>
<td>80.7</td>
<td></td>
</tr>
</tbody>
</table>

In the Atlantic Basin area, five countries produced around 2 tcf (43 million tonnes) in 2004 which is about 30 percent of total worldwide LNG production. LNG production would more than triple by 2010 with both green-field and expansion projects totaling 4.4 tcf (95.6 million tonnes) of capacity under construction. If announced projects proceed as planned, Venezuela, Angola, Equatorial Guinea, Russia and Norway could join the group of LNG exporters in the Atlantic Basin by 2010.

Pacific Basin
The Pacific Basin imports 66% of LNG produced worldwide. Japan is the leading importer of LNG in the Pacific Basin (and worldwide), followed by South Korea. Japan imports about 45% of the world’s LNG. Indonesia alone supplied 19 percent and Malaysia, 16 percent; most of whose LNG goes to Japan. In the Pacific Basin area, eight countries produced around 5 tcf (109 million tonnes) in 2004. New LNG trains are under construction which will increase the supply by 75%. Core demand for LNG is still expected to come from the established markets in Japan, Korea and Taiwan, but new emerging markets in India and China.

LNG Value Chain
On the question of cost and price, the LNG value chain represents investment commitments for the parties involved. However, the cost estimates for importing LNG are considerably less than when the LNG industry was launched roughly 40 years ago. Substantial savings have been achieved for both liquefaction and shipbuilding, and, importantly, the life spans of LNG tankers have been extended. The LNG value chain today encompasses significant technology improvements for cost reductions as well as safety and environmental enhancements and protections. Overall, the average costs for liquefaction, shipping and regasification have declined.

<table>
<thead>
<tr>
<th>Typical LNG Value Chain Costs</th>
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<tbody>
<tr>
<td>EXPLOITATION &amp; PRODUCTION</td>
</tr>
<tr>
<td>$1.5-$2.5 billion</td>
</tr>
<tr>
<td>90.5-91.0/MMcft</td>
</tr>
<tr>
<td>TOTAL</td>
</tr>
</tbody>
</table>

Greatest variability is in upstream feedstock for liquefaction.
overall capital cost of LNG supply chains are expected to continue to fall. Total capacity requirement have fallen from around $700 per tonne in the mid-1990s to around $500 per tonne in 2003. Costs are projected to fall to $420 per tonne by 2010 and $320 tonne by 2030. This assumed a shipping distance of about 4,000km.

liquefaction

Nominal liquefaction capital cost had fallen from $550 per tonne of LNG capacity on average in 1990 to $195 in 2005. According to IEA, recent liquefaction plants being built in plants, improvements in liquefaction technology, and improved economies of scale. The improvements in liquefaction technology have included optimization of air and water-cooling, and a reduction in design redundancy.

Transport

The cost of building LNG carriers has fallen from an average of $250 million to $170 million, more than 30%, between 1992 and 2002. However, due to increased demand and costs of materials (especially steel), this trend has slowed even when having tanker costs drift higher. Larger tankers and cargoes, coupled with expanded terminals to handle the bigger vessels, and enhanced tanker efficiencies have both lowered shipping costs substantially. In March 2006, ConocoPhillips signed a contract with Samsung for three 270,000 cubic meters LNG tankers for delivery in 2009. Ships will use the membrane cargo containment technology. Currently, the biggest LNG ship can carry almost 150,000 cubic meters. The trend for larger LNG tankers continues. LNG tankers twice that size - over 300,000 cm are already being designed. By 2010, LNG carriers with 320,000 to 350,000 cubic meters of capacity may be possible.

Transportation costs are one of the expenses in LNG chain. Applying economies of scale by increasing the size of the vessel’s cargo, a saving on the unit transportation costs can be made. So far, the vessels constructed have been restricted by terminal design. It may be possible that new terminals coming on line will have the flexibility to accommodate larger vessels. All the yards involved in LNG already have plans in hand for the construction of Very Large LNG Carriers (VLNGCs). The ability of fixed receiving terminals to handle very large ships may limit the ultimate volume they will transport. Offshore regasification terminals will likely not have this constraint.

Tanker Cost are Dropping

New designs of vessels are being developed in addition to the increases in size mentioned before. Firstly, tankers that incorporate regasification facilities onboard have been built and are in operation. The allows for the direct offloading of natural gas into existing natural gas infrastructure thus avoiding LNG handling at terminals. Secondly, with the recent development of LNG liquefaction plants in severe Arctic conditions new carriers are being designed and built to serve Snohvit and Shottonmark terminals. As tankers return empty after offloading their LNG cargo, finding other cargoes for the return trip could help defray those costs though dual purpose tankers have not been developed to date.

Regasification

Average unit regasification terminal costs are currently around $86 million per bcm per year capacity, accounting for 20% of the total cost of an LNG chain, not including upstream development. On average regasification cost are projected to fall by the IEA, mainly due to economies of scale to $77 million by 2010 and $65 million by 2030 (see chart to the left). On arrival at the receiving terminal in its liquid state, LNG is pumped first to a double-walled storage tank, similar to those used in the liquefaction plant, then it is pumped at high pressure through various terminal components where it is warmed in a controlled environment. The vaporized gas is then regulated for pressure and enters the U.S. natural gas pipeline system. Finally, residential and commercial consumers receive natural gas for daily use from local gas utilities or in the form of electricity.

LNG Pricing Mechanisms

International gas pricing structures have evolved over time. The LNG pricing had traditionally been indexed on competing fuels. There have been three distinct and relatively independent markets for LNG. In the U.S., the competing fuel is pipeline natural gas, and the index price is Henry Hub price for short term sales. The LNG transactions in the U.S. are therefore subject to a high degree of price volatility. The Trinidad LNG contracts are based on Henry Hub. In Europe, LNG prices are related to competing fuels such as low-sulfur residual fuel oil. There have been recent linkages to natural gas spot market and futures prices. In Asia, prices are linked to imported crude oil prices. The index price is essentially that of crude oil plus an adjustment factor calculated based on the rate of inflation.

The destination of the LNG cargo has also an impact on the determination of the price. For example, Algerian imports to Europe and Japan are priced based on crude and/or product prices in respective regions. The oil indexing base could differ widely from contract to contract. Prices can also be tied to the price of alternative fuels, such as coal in the case of power plants. This way, power plant managers will be able to see that using LNG is comparable to using coal in generating electricity. Eventually, as the market for LNG increases in volume and more buyers and sellers interact, spot and futures market may be developed. The Asian prices are generally higher than prices elsewhere.

LNG Prices versus Henry Hub and Brent

Greater interactions between swing suppliers to both markets will likely cause prices to converge over time. In the future, the LNG market may become more like the oil market of today, in which substantial sales and purchases are made on the spot market, and firms invest in infrastructure without first arranging long-term contracts with specific trading partners. Global LNG market could use the New York Mercantile Exchange (NYMEX) as its primary pricing point, with other trading centers emerging in Belgium, Tokyo, and other locations, all indexed off NYMEX. This would operate in much the same way as the oil markets with West Texas Intermediate, Brent Blend, and Dubai serving as benchmarks.

Project Ownership and Financing

Because of the large sums and risks involved, financing arrangements are crucial to the LNG project development process. Almost all projects that
have been developed on the basis of long-term contracts between the different parties along the supply chain i.e., the gas producer, the liquefaction project sponsors, the LNG buyer and large final consumers. Until now, no liquefaction plant or receiving terminal has been built without long-term contracts covering the bulk of the capacity. Although long-term contracts will probably remain the backbone of the LNG industry, they will become shorter and take-or-pay commitments may become less onerous.

The upstream facilities and LNG liquefaction plant are structurally separate, although the partners in both may be the same. The LNG buyer is normally responsible for financing the construction of the import terminal. Either the upstream/liquefaction project developer or the buyer is responsible for arranging financing for the ships, on a separate basis from both the liquefaction and receiving terminal projects. Different players are involved in different parts of the LNG chain. In 2001, more than 60% of the equity in global LNG liquefaction capacity was owned by state companies, in some cases in a joint venture with a major oil and gas company.

Ownership of LNG Liquefaction Capacity

Since the start of commercial sales over 40 years ago, the LNG industry has grown based on fixed trade routes and long-term contracts. Typically, the new LNG projects have a build-up period or ‘wedge’ as buyers increase commitments to full contracted volumes. In addition, the LNG projects typically have some margin engineered into them resulting in spare capacity. Often this spare capacity is increased through minor upgrading or de-bottlenecking, once performance has been established. Whereas the existing buyers have usually committed to these incremental volumes over time, in 1986 Kogas started LNG imports into Korea based purely on this surplus capacity from projects developed to supply Japanese power and gas utilities.

Technology-driven cost reductions such as those cited earlier has made it possible for developers to obtain financing to build plants without long term contracts. Newer plants are also being designed to have excess capacity that can be used to supply a growing short-term or spot market for LNG. Buyers in the Atlantic Basin in particular (Puerto Rico, Dominican Republic, Greece) are finding that this spot market based on excess capacity is reliable. This is a change from the long-term, inflexible contracts of the past.

New, more flexible, commercial arrangements are supporting these new market dynamics. Non-traditional buyers are emerging who require a less traditional contracting approach, as evidenced by the increasing number of short-term LNG trades over the last few years. Customers are seeking to manage seasonality and load variation with more innovative contracting strategies that do not always involve additional investments in LNG storage tanks and ships.

Evolution of LNG Contracts

<table>
<thead>
<tr>
<th>Market</th>
<th>1980's</th>
<th>1990's</th>
<th>2000's</th>
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<tbody>
<tr>
<td>Japan</td>
<td>1980's</td>
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<td>2000's</td>
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<tr>
<td>U.S.</td>
<td>Low CAPEX</td>
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<td>Sold through</td>
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<td>Contract Terms</td>
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<tr>
<td>Yielding</td>
<td>Low yield</td>
<td>Low return</td>
<td>High yield/High return</td>
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</tbody>
</table>

Potential for LNG Spot Trade

The commodity potential of LNG is greater than that of other energy products. There are several reasons for this:

• Cargoes of LNG have a narrow range of quality (BTU value), much less than crude oil’s thus reducing the possible market segmentation.

• Most ships are of a similar size range and have similar configurations: A ship starting from any Atlantic source location could sail for any import terminal in the Atlantic Basin.

Trinidad & Tobago has replaced Algeria as the primary source of supply for the U.S., with cargoes coming also from Qatar, Nigeria, Australia, and Oman. Although the long-term contracts with the primary suppliers are still important, spot market sales are becoming much more common. In 2006, the main limitation to the growth of spot trading is the lack of uncommitted shipping capacity, whereas in the mid 1990s there were several vessels available for term and voyage charter - the first phases of the Atlantic and Nigeria LNG projects absorbed much of this capacity in order to minimize the initial project investment requirements.

Access to regasification terminals and pipelines present a greater challenge. Much of the transportation capacity within Europe remains tied up with existing long-term take-or-pay contracts thus restricting access for new volumes. For this situation to change, the regulation underway will need to effectively address all areas of network codes and rules of operation at LNG terminals. This would allow fair access and fair tariffs for new entrants. Many of the existing LNG import terminals in Europe could be easily expanded.

Challenges to Building LNG Infrastructure in the U.S.

Although importation of LNG from around the world was an important component of North America’s plans to restore energy security in the 1970s, there has not been any new LNG import facilities developed on the continent for the past 20 years. In order to accommodate an increase in imported LNG, the number of receiving and regasification terminal capacity must be increased. Some of this capacity increase will be attained through expansion projects at the existing facilities. In addition, new facilities will need to be built, and a number of new marine import terminals have been proposed not only in the U.S. but also in Canada and Mexico.

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Of note are proposals to build LNG import facilities in Canada and Mexico. Canada's Atlantic coast, once thought to be highly prospective for natural gas, could provide a key entry point for LNG cargos destined for use in both eastern Canada and the northeastern U.S. Two terminals of 1 Bcf per day send-out capacity have already been approved, while six more have been proposed. Mexico has three approved LNG terminals with 3.1 Bcf per day total capacity. Currently, five more regasification terminals have been suggested to be built mainly on Mexico's Pacific coast, which would be capable of supplying at least 3.8 Bcf a day. Proposed LNG receiving terminals in the Baja region could export surplus natural gas to California and provide critical incremental supplies to balance western natural gas markets. Additional proposed terminals further south on Mexico's Pacific coast and in the Yucatán would provide indirect support to North American natural gas balances by serving growing natural gas demand elsewhere in Mexico.

Clearly, not all of these projects will be built, as there is no demand for all of the capacity (see chart above). The EIA forecast indicated that 11.9 bcfd or 4.4 tcf per year of LNG would be required by 2030. This means about four to five new terminals averaging one bcfd capacity each might be needed in addition to the planned expansion of the existing terminals and from only one or two new terminals would be needed by 2010. A number of risks will impact prospective LNG import capacity development. For example, natural gas market dynamics (shifts in supply, demand and thus price) could occur that would alter the outlook for increased imports. In contrast, difficulties in siting and permitting new import terminals could delay growth in LNG imports, possibly contributing to higher prices and related disruptions.

The challenges facing the development of new LNG infrastructure in the U.S. include permitting and siting issues, (local acceptance, safety and security, federal and state and local approvals), natural gas transmission system issues (location of demand for natural gas, take away capacity, natural gas interchangeability), and natural gas market issues.

Relevant Case Studies:
- Gas Monetization in Bangladesh
- Gas Monetization in Bolivia
- Gas Monetization in Nigeria
- Natural Gas Marketization in North America
- Trinidad LNG Project

CHAPTER 13

REFINING AND MARKETING

Refining
Crude oil is not useful in its pure form as extracted from the ground; it needs to be refined into products such as gasoline, fuel oil, and so on. Demand for crude oil is a derived demand, that is, it depends on the demand for petroleum products. For example, demand for crude oil increases during the winter months of the northern hemisphere as...
demand for heating oil increases in North America and Europe. Similarly, during summer months, increased demand for gasoline and jet fuel along with increased traveling causes the demand for crude oil to surge. In the early 1980s, the refining industry, producing companies realigned their businesses by extending their operations to downstream such as refining and marketing to avoid the overproduction. High transaction costs involved in selling crude oil could be avoided. Vertically integrated companies enjoyed the benefits of low transaction costs and ready markets for their products for a long time.

However, following the oil shocks of the 1970s changing market conditions caused people to think that the separation of upstream and downstream operations may not be the best thing. This is because crude oil has become much easier to sell at very high prices. Increasing world demand allowed these companies to sell all they could produce by offering prices slightly below the official OPEC price. Given high refining margins and selling their crude oil, companies did not need their downstream businesses any longer, especially in a time where downstream operations started to become highly competitive.

Before the first oil shock, in addition to transportation crude oil and its products were used for residential heating as well as power generation in the U.S. and Europe, creating a significant demand for fuel oil essentially. Increasing traveling by citizens of these developed countries also created demand for gasoline and jet fuel. But, higher crude oil prices led to conservation, increased efficiency and fuel substitution. Coal, natural gas and nuclear power have become significant alternatives for fuel oil in power generation. In the U.S., the share of coal in electricity generation has increased by more than 50% over the last several decades. In the 1980s, the second largest source of electricity with roughly 20%. The amount of electricity generated by coal more than doubled since the first oil shock. Before the early 1970s, there were practically no nuclear power plants in the world. Natural gas became a significant option for fueling power plants as well as for residential heating.

As a result of declining demand for refinery products even in most affluent markets, product margins started to shrink. Also, the belief that the price of oil would stay high forever caused major oil companies to invest heavily in the Middle East and in Singapore, were built for product exports. Refineries in the Middle East and in Singapore, were built for product exports. Refineries in the Middle East and in Singapore, were built for product exports. Refineries in the Middle East and in Singapore, were built for product exports. Refineries in the Middle East and in Singapore, were built for product exports. Refineries in the Middle East and in Singapore, were built for product exports. Refineries in the Middle East and in Singapore, were built for product exports. Refineries in the Middle East and in Singapore, were built for product exports. Refineries in the Middle East and in Singapore, were built for product exports. Refineries in the Middle East and in Singapore, were built for product exports. Refineries in the Middle East and in Singapore, were built for product exports.
Refinery Margins in the U.S. (cents per gallon)

The uncertainty about the future demand for each product used to create some problems for refineries. However, global markets are fairly developed and well connected so that product prices are fairly in equilibrium around the world. Development of spot and futures markets expedited the globalization of the product market. New York Mercantile Exchange (NYMEX) has 24-hour electronic trading which connects Asian markets in real time regardless of time differences. Refineries almost anywhere in the world can market any surplus product they may have in these markets. For example, the U.S. East Coast has the option of receiving its heating oil supplies from the Gulf Coast or Rotterdam markets. Japan is in the enviable position of trading with the U.S. West Coast, Singapore or the Persian Gulf. Similarly, the Mediterranean region has several alternatives in Russia, Persian Gulf or Rotterdam for its product supplies. These regions also serve Western Europe.  

Refining Technology

The core refining process is simple distillation (see graphic below). Because crude oil is made up of a mixture of hydrocarbons, this first and basic refining process is aimed at separating the crude oil into its “fractions,” the broad categories of its component hydrocarbons. Crude oil is heated and put into a still -- a distillation column -- and different products boil off and can be recovered at different temperatures. The lighter products -- liquid petroleum gases (LPG), naphtha, and gasoline -- are recovered at the lowest temperatures. Middle distillates -- jet fuel, kerosene, distillates (such as home heating oil and diesel fuel) -- come next. Finally, the heaviest products (residual fuel oil) are recovered, sometimes at temperatures over 1000 degrees F. The simplest refineries stop at this point.

Additional processing follows crude distillation, “downstream” (or closer to the refinery gate and the consumer) of the distillation processes. Downstream processing encompasses a variety of highly complex units designed for very different upgrading processes. Some change the molecular structure of the input with chemical reactions, some in the presence of a catalyst, and some with thermal reactions. In general, these processes are designed to take heavy, low-valued feedstock -- often itself the output from an earlier process -- and change it into lighter, higher-valued output. A catalytic cracker, for instance, uses the gas oil (heavy distillate) output from crude distillation as its feedstock and produces additional finished distillates (heating oil and diesel) and gasoline. Sulfur removal is accomplished in a hydrotreater, which reforming units generate higher octane components for gasoline from lower octane feedstock that was recovered in the distillation process. A coker uses the heaviest output of distillation, the residue or residuum, to produce a lighter feedstock for further processing, as well as petroleum coke.

A Model of Refining Investment

The simple model presented in this chapter is for a plant capable of processing 50,000 b/d (see tables at the end). We assume that our company plans to buy this plant for $100 million. The product mix is set such that 100 barrels of crude oil yield 25 barrels of light oil (gasoline, LPG, and so on), 40 barrels of middle distillate (kerosene, diesel, and the like) and 31 barrels of heavy oil (fuel oil, various grades of residual or “resid”) when refined. Product prices are tied to the price of crude oil. A barrel of light oil is priced 35% more, a barrel of middle distillate is 32% more and a barrel of heavy oil is 35% less than price of a barrel of crude oil. Operating and maintenance (O&M) costs are $1.20 per barrel. In order to evaluate the project, we need to estimate cash flows over the expected lifetime of the refinery (20 years in this case). The annual cash flow is defined as follows.

\[
\text{(weighted product price} = \frac{3 \sum j \ p_j}{3}]
\]

where \(p_j\) is the price of the \(j\)th product relative to the price of crude oil.

As one can see from the spreadsheet, the above assumptions lead to an NPV equal to $60.28 million that corresponds to an IRR of 21%. Once this base case (most likely) scenario is established, managers or executives, who will decide on whether to go ahead with the project or not, may be interested in other outcomes and their probabilities. After all, as we discussed there are uncertainties about the product margins, O&M costs, and so on. For example, what would happen to the project’s returns if light oil cannot be sold at a price 35% higher than the price of oil, but only 30% higher. Our recalculations show that the project NPV falls to $36.61 million and the project IRR is down to 17%. If, instead, the market for middle distillate is tight and the refiner cannot get a price more than 27% higher than the price of oil (instead of 32% higher), the NPV falls to $22.40 million and the IRR falls to 14%. The second example is comparable to the case of decreasing fuel oil demand we discussed in the Previous section.

There are other scenarios that may be of interest to decision makers. They may want to learn what would happen to returns if the refinery ends up processing only 45,000 b/d instead of 50,000 barrels as originally expected. In this case, NPV falls to $47.22 million and the IRR is now 19%. On the other hand, an increase in O&M costs from $1.2 per barrel to $1.5 per barrel causes NPV to fall almost 50% to $31.87 million, corresponding to an IRR of 16%. These kinds of sensitivity analyses can be done for as many values as possible. It can also be carried out simultaneously for different values of more than one variable. For example, if we consider lower prices for both light products and middle distillate we discussed above, the project NPV becomes negative and the IRR becomes 10%. Under these circumstances, the project becomes unacceptable. The company may decide to upgrade the refinery by installing a coker to get rid of heavy oil and obtain more of lighter products instead. The NPV of this incremental project (the coker) would be $20.29 million corresponding to an IRR of 12% despite the initial investment of $160 million. Below a
comparison of cash flows from the original refinery project and the coker project is presented. Despite high initial investment, net cash flows from the coker surpass those from the refinery throughout the 20-year life of these projects (see tables at the end). The share of heavy oil and its price are taken from the original refinery model discussed earlier. We assumed that, out of 100 barrels of fuel oil, the coker can refine 32 barrels of light products, 47 barrels of middle distillate and 18 barrels of petroleum coke. Prices of light oil and middle distillate are respectively 35% and 32% higher than the price of crude oil (as we assumed in the previous exercise). Petroleum coke can be sold for a price roughly equivalent to 25% of the price of crude oil.

Again, it is a worthwhile exercise to analyze how changes in crucial variables impact the project returns. Revisiting some of the examples from the original refinery model, we can test the effect of a decline in the price of light products from 35% higher than that of crude oil to 30% higher. In this case, the NPV falls to $11.88 million and the IRR falls to 11%. If, instead, a similar decline in the price of middle distillates is analyzed, the project NPV falls to $7.94 million and the project IRR falls to 11%. As seen in the previous chapter, a simulation model is able to provide more accurate evaluations with probabilities assigned to each possible outcome. It would actually enable the executives making decisions to calculate the probability of this refinery project yielding a negative net present value. Then it would be a question of whether this probability is acceptable or not. The only drawback is gathering considerable amount of data about variables of interest so that one can create the distributions that most realistically represent the behavior of these variables. As discussed earlier, the price of crude oil as well as product prices creates a challenge, as their historical data does not fit standard bell curve distributions very well. While it is difficult to analyze historical data on crude oil and product prices, the general historical relationships among crude oil and product prices and demand are well established.

It is important to note that a more complex simulation model would also accommodate other important variables such as changing feedstock costs and product prices. A drop in fuel oil feedstock costs would initially cause refining profit margins to fall. Rising demand with lower prices on petroleum products would eventually cause refining margins to improve. Conversely, an increase in feedstock costs would initially trigger an increase in refining margins. However, demand for petroleum products would eventually diminish in response to higher product prices, causing those prices to soften and refining margins to suffer.

A Model for Refinery Investment

| Processing capacity | 50000
| Depreciation rate | 0.1
| Tax rate | 0.4
| Discount rate | 0.1
| O&M cost | 1.2
| Price of Crude Oil | share/price coeff.
| Light oil | 0.32
| Middle Distillate | 0.47
| Petroleum coke | 0.18

Incremental Refinery Project - Coker

| Processing capacity | 50000
| Depreciation rate | 0.1
| Tax rate | 0.4
| Discount rate | 0.1
| Price of crude oil | share/price coeff.
| Light oil | 0.32
| Middle Distillate | 0.47
| Petroleum coke | 0.18

Marketing

Marketing petroleum products, especially gasoline, is a risky business because of the highly competitive nature of many markets as well as the uncertain nature of demand and supply conditions. In countries where competition in retail marketing exists, it is difficult to pass on increases in the price of crude oil to customers. The market is affected by seasonal fluctuations as well as by developments in the global or local crude oil markets. Despite the risks involved, opening a gasoline station usually requires a small initial investment and can provide a higher return on investment compared to E&P and refining operations we considered in previous chapters. If a company decides to open a chain of stations at the same time, a considerable amount of capital may be necessary. However, most gas stations are operated as franchises by individual investors.

In the U.S., competition is quite fierce in marketing and one can observe the level of competition at any major road intersection where each corner is occupied by a gasoline station. Traveling around a city, one will also notice that prices tend to be higher at gas station networks, which are the only stations in a neighborhood or in more well-to-do neighborhoods. On the other hand, sales volume may be much lower in these areas compared to major intersections where four gasoline stations compete with each other usually by lowering their prices. Creating a brand loyalty has also been a strategy used by major oil companies.

Gasoline stations underwent significant changes over the last twenty to thirty years. Especially after the crash of world oil prices in 1986, cost-cutting measures such as switching to self-service from full-service have become even more popular in the U.S. A general trend is for service station operators to diversify their sources of revenue by offering other services such as convenience store shopping. Another strategy that has become widespread is co-branding gasoline stations with big name fast food restaurants.

In Europe, the level of competition has been lower because of the extent of government intervention in product pricing through high taxes and price controls. This situation not only creates higher profit margins, but also makes working capital needs for marketers are allowed to delay their tax payments for up to 45 days. Nevertheless, downstream operations are still fiercely competitive. Actually, the tightness of margins in marketing has forced two of the largest oil companies, Mobil and BP to merge their refining and marketing operations in Europe. In the late 1990s, this merger, which was initially fueled by competition from supermarket chains offering gasoline to their customers, is considered the first example of a general trend in the industry, which needs to find a way to deal with low profit margins and overcapacity. Star (a joint venture between Kuwait and Texaco) and Shell proceeded with a similar merger in the U.S., and Texaco and Shell pursued a union of their downstream operations. Other big companies and independent refiners and marketers are expected to follow this trend.

Shell-Texaco alliance drew considerable criticism from independent marketers that sold about 50% of gasoline in the U.S., but were concerned that such mergers would lower their share in the future. Both Texaco and Shell had large marketing share as well as brand recognition. Antitrust regulators scrutinized these and other mergers that followed (in particular those involving major brand names: BP-Amoco-Arco, Exxon-Mobil, Chevron-Texaco, and Conoco-Phillips) and required necessary divestitures.
to prevent any one company acquiring a dominant position in any regional market. Nevertheless, these mergers further challenge the ability of independent marketers to access and to choose among suppliers. Smaller marketers may not be able to meet minimum volume requirements or comply with franchise agreements. Moreover, the competition in marketing is expected to increase further as supermarkets and mega stores such as Walmart, Costco and Sam’s Club in the U.S. enter the gasoline marketing business as similar entities did in Europe. The biggest threat to independent marketers is the fear that these supermarkets consider gasoline sales as a way of attracting customers to their stores (a form of advertisement), and therefore can afford to offer lower prices. Another challenge facing smaller independents is the compliance with environmental regulations, such as upgrading underground storage tanks, which increases operating costs of marketers.

As a result of these developments, a smaller number of independent marketers are expected to survive in the future, and those that remain are expected to be larger than the average marketer today because of mergers and acquisitions. However, competition will probably be as fierce as it is today, forcing marketers to look for ways to diversify their revenue sources. This analysis is not unique to the U.S. and Western Europe where product markets are developed. Companies are facing same kind of competition in emerging markets. One of the innovative approaches to differentiate itself from competitors is originated by Agip SPA of Italy in Russia, where the company started to use a mobile gasoline station for delivering fuel to remote areas.

### The Case of Gasoline in the U.S.

Gasoline, one of the main products refined from crude oil, accounts for about 16 percent of the energy consumed in the U.S. While gasoline is produced year-round, extra volumes are made in time for the summer driving season. Gasoline is delivered to oil refineries mainly through pipelines to a massive distribution chain. There are three main grades of gasoline: regular, mid-grade, and premium. Each grade has a different octane level. Price levels vary by grade, but the price differential between grades is generally constant. The cost to produce and deliver gasoline to consumers includes the cost of crude oil to refiners, refinery processing costs, marketing and distribution costs, and finally the retail station costs and taxes. The prices paid by consumers at the pump reflect these costs, as well as the profits (and sometimes losses) of refiners, marketers, distributors, and retail station owners.

Federal, State, and local taxes are a large component of the retail price of gasoline. Taxes (not including county and local taxes) account for approximately 31% of the cost of a gallon of gasoline. Within this national average, Federal excise taxes are 18.4 cents per gallon and State excise taxes average about 20 cents per gallon. Also, eleven States levy additional State taxes on gasoline. Some of which are applied to the Federal and State excise taxes. Additional local county and city taxes can have a significant impact on the price of gasoline.

### Refining Costs and Profits

Refining costs and profits comprise about 13% of the retail price of gasoline. This component varies from region to region due to the different formulations required in different parts of the country. Distribution, marketing and retail dealer costs and profits combined make up 13% of the cost of a gallon of gasoline. From the refinery, most gasoline is shipped first by pipeline to terminals near consuming areas, and then loaded into trucks for delivery to individual stations. Some retail outlets are owned and operated by refiners, while others are independent businesses that purchase gasoline for resale to the public. The price on the pump reflects both the retailer’s purchase cost for the product and the other costs of operating the service station. This reflects local market conditions and factors, such as the desirability of the location and the marketing strategy of the owner.

Even when crude oil prices are stable, gasoline prices normally fluctuate due to factors such as seasonality and local retail station competition. Additionally, gasoline prices can change rapidly due to crude oil supply disruptions stemming from world events, or domestic problems such as refinery or pipeline outages. The main underlying challenge facing the U.S. gasoline market is the persistent lack of sufficient gasoline producing capacity. This is the result of the decline in the number of U.S. refineries in the last two decades. U.S. refining capacity, as measured by daily processing capacity of crude oil distillation units alone, has appeared relatively stable in recent years, at about 16 million b/d of operable capacity. The first refineries that were shut down as demand fell in the early 1980’s were those that had little downstream processing capability. Existing refineries have expanded, with particular emphasis on upgrading capacity. But there is a limit to refinery extensions. As a result, U.S. refiners have not been able to produce sufficient gasoline to totally meet domestic needs.

### A Model for Marketing Investment

A simple model is presented at the end of the chapter. As one can see from the first column, an initial investment of $250,000 is sufficient for a gasoline station with a maximum sales volume of 500,000 gallons a year. We assume a profit margin of 10 cents per gallon (with the price of gasoline $1.00 a gallon and O&M cost 90 cents a gallon). We also assume that the land the station is built on appreciates by 2% a year. This is important, because the value of the land will be salvaged when sold at the end of the economic life of the station, and added to the cash flow, which is calculated as follows:

\[ \text{Cash Flow} = \text{After-tax Income} - \text{Initial Investment} - \text{Depreciation} - \text{Working Capital} \]

\[ = \left( (1 - \text{Tax Rate}) \times \frac{\text{Price-Oil & M}}{\text{Volume}} \right) - \text{Depreciation} - \text{Working Capital} \]

For the last year we need to add the value of the land and total working capital assumed to be liquidated and returned to the company as cash at the end of project’s life. In this case the value of the land above the NPV of after-tax cash flows over twenty years equals $53,160 with an IRR of 13%

Our example represents quite effectively the tightness of margins and sensitivity of revenues to fluctuations in profit margins. Consider a one-cent increase in O&M costs from 90 cents per gallon to 91 cents per gallon. As a result, NPV falls almost 45% to $30,110. The project IRR remains fairly constant at 12%. A decrease in sales volume from 500,000 gallons a year to 450,000 gallons a year has a similar impact: the NPV falls to $31,150, and the IRR declines to 12%. Decreasing sales volume is a natural outcome of increased competition by new gasoline stations being opened across the street. If we consider the combined impact of higher O&M costs and lower sales volume, the project yields an IRR of 11% and a NPV of $10,410. Obviously, any further decline in sales volume and/or increase in O&M costs will render the project less attractive.

When we evaluate cash flows to be generated by adding a convenience store to the station, we obtain the model presented in the second table below. We assumed that the foodmart is able to sell 80 cents worth of goods for each gallon of gasoline sold. All other variables have the same value as in the original model. Addition of foodmart increases the NPV value of the station to $237,520 from $53,160. The new IRR is a much more respectable 23% as opposed to 13% the original gasoline station project provided. This simple example supports our discussion about how competitive the marketing business is and the importance of adding value to the station’s operations by providing additional services.

If we repeat our scenario analysis for the gasoline station with foodmart, we obtain following results. A one-cent increase in O&M costs does not affect the returns to project significantly as the IRR falls slightly to 21% and the NPV remains fairly high at $214,480. Lower sales volume (450,000 gallons instead of 500,000) has a more significant impact: the project IRR is down to 19.7, and the IRR is now 20%. Taken together, higher costs and lower sales lower the IRR to 19% and the NPV to $176,330. Nevertheless, the gasoline station with a foodmart is a better project than a conventional gasoline station. Clearly foodmart generates significantly larger cash inflows throughout the 20-year life of the gasoline station, and accordingly raises the viability of the project.

### Relevant Case Studies:

- Brazil's Restructuring of the Oil & Gas Industry
- Deer Park Refinery
Coal is projected to continue to retain the largest market share of electricity generation, but its importance is expected to be diminished somewhat by the rise in natural gas use. The role of nuclear power in the world's electricity markets is projected to grow by more than 30%, but their share of total electricity generation is projected to remain near the current level of 20 percent. Electricity markets of the future are expected to rely increasingly on natural-gas-fired generation. This trend is evident throughout the world, as industrialized nations are intent on using combined-cycle gas turbines, which generally are cheaper to construct and more efficient to operate than other fossil-fuel-fired technologies. Natural gas is also seen as a cleaner fuel than other fossil fuels. Worldwide, natural gas use for electricity generation is projected to double by 2030, as technologies for gas-fired generation continue to improve and ample gas reserves are exploited.

To meet the increasing demand, the industry will have to invest billions of dollars. There have been two important developments in the electricity sector in recent years that may affect the way the industry meets these investment requirements, both from financial and technological perspectives (which may also affect the fuel portfolio projections provided above). The first is electricity industry restructuring. Many countries have implemented reforms to unbundle generation, transmission and distribution (T&D), and marketing functions of vertically integrated electric utilities. Then they provided open access to T&D (which remained a natural monopoly) to allow for competition to flourish in the generation and marketing (both wholesale and retail) marketplaces. The second important development, which mainly resulted from the first, is the increasing role of foreign direct investment in the developing regions of the world. Greater flexibility in the investment environment has allowed developing nations to construct the infrastructure needed for substantial increases in access to electricity, a particular problem for many developing nations.

### Power Plant Economics

#### Key Considerations

Investment in plants is a complex decision process that is governed by many variables which are not mutually exclusive and several decision iterations are needed to reach an economically and environmentally sustainable investment decision. Failing to accurately quantify each of these variables may result in adverse effects on the overall outcome of the project. Therefore, it is imperative to identify each of these variables, understand how they interact with each other and how they can be integrated to produce a profitable project that provides investors with the right risk-return ratio. Fuel prices, expected load curve, the level of competition (laws & regulations), construction and operational (especially fuel) costs, environmental regulations, economical conditions and, in many parts of the world, political conditions are some of the variables that need to be estimated. They may all have significant impact on project NPV and IRR.

Electricity industry restructuring has created new opportunities for merchant power plant construction. Independent power producers (IPPs) have invested billions of dollars all around the world (see Chapter 1 for an overview) replacing traditional integrated utilities. At the same time, higher competition can bring about challenges. By having a better understanding of the present and future load curves, a thorough knowledge of political, economical and environmental factors, and, perhaps most importantly, the ability to keep up with and commercialize technological advances appear to be key requirements for success in this new environment.

In a regulated market, selectivity and optionality concepts in power generation projects are not applied. In the regulated environment or in places where state monopolies dominated, large scale investments in hydro, coal and/or nuclear facilities were preferred and sometimes easily financed either through regulated rates or through state funds. In the competitive environment, however, power plants need to be evaluated based on traditional project finance methods.

As discussed in Chapter 1, the technological developments in gas turbines allowed gas-fired power plants to become the choice of investors. These plants can be built in relatively short time, have lower construction cost, and shorter construction time. One can also run these units only during peak hours as they are easy and cheap to turn on and off unlike coal or nuclear plants that are better suited for base load. Accordingly, optionality is very important for gas-fired plants.

### Costs

Electricity demand fluctuates throughout the day as well as across seasons. Nevertheless, there is a constant amount of load at all times to perform commercial and industrial equipment as well as home appliances that are always on. This is called the base load. Then, throughout the day, the load fluctuates depending on the need for lighting, heating, cooling and so on. Typically, during winter, there will be an increase in load in the mornings when people get up and the heat systems are ready for work and/or school. There will be another increase in the early evening hours when people return home, cook, dine, watch TV, and so on. The farther north it is and the greater the percentage of electric heating, the larger the increase will be. These increases are known as peak load, or peak demand. In summer, peaks will coincide with afternoons and early evenings when the need for air conditioning would be largest.

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**CHAPTER 14**

### REFINING AND MARKETING

The EIA projects the worldwide electricity consumption to increase at an average annual rate of 2.7% from 1999 to 2020. The most rapid growth in electricity use is projected for the developing world, particularly developing Asia, where electricity consumption is expected to increase by 4.5% per year. Similarly, the expected growth rate for electricity use in Central and South America is 3.9% per year. Electricity consumption in the industrialized world is expected to grow at a more modest pace than in the developing world, at 1.9% per year.
Uses of Generating Units

**Base Load Unit**
Generates the minimum or baseload requirement of the power system; operates at a constant rate and runs continuously.

**Peak Load Unit**
Used to meet requirements during the periods of greatest demand.

**Intermediate Load Unit**
Used during the transition between base load and peak load requirements.

**Reserve or Standby Units**
Available to the system in the event of an unexpected increase in load or outage.

These variations in the daily load curve are crucial for running power plants. Some power plants are better suited for meeting the base load and others are very efficient as peaking units, i.e., plants to be run when the load peaks. In general, high capital cost plants such as coal and nuclear-fired facilities are built in larger sizes and cannot be turned on and off easily, or economically. So, they are ideal for running all the time to meet the base load.

On the other hand, cheaper, more modular gas-fired units that can be built faster and at lower cost, and, more importantly, can be turned on and off within 15 minutes notice, are well suited for meeting the peak demand. In restructured markets, where the price of electricity is allowed to fluctuate along with the load curve, peaking plants offer opportunities for IPPs as well as marketers. Accordingly, gas-fired facilities are more in demand in these markets than traditional base load plants. Nevertheless, as population and/or economy grow in any region, the base load as well as the peak load will increase (despite our best efforts to conserve). There will hence be a need for all kinds of generation facilities (unless scenarios about distributed generation, grid-independent generation and alternative technologies become a reality much sooner than many think). It is therefore useful to consider the costs of generation technologies.

The capital costs associated with building generation capacity for a wide range of technologies from conventional thermal to alternative technologies such as wind, solar and biomass can be seen in the chart below. Clearly, the alternative technologies, except for wind, are significantly more expensive than conventional technologies. For example, MSW costs more than ten times per kW as conventional combined-cycle, and more than three times as nuclear capacity, which is among the costliest of traditional technologies.

Lowest capital costs are associated with advanced combustion turbine technology (gas-fired) at $320 per kW, followed by other gas-fired technologies such as advanced combined-cycle, conventional combined-cycle and conventional combustion turbine. Note that all of these cost less than half of next cheapest technologies, which are wind and oil/gas steam. Coal-fired plants, though not as expensive as nuclear plants, cost up to four times as much per kW as most gas-fired plants.

In addition to capital costs, investors need to consider operation and maintenance (O&M) costs as well (see chart above). Unlike the capital costs, conventional technologies have much larger variable O&M costs than the alternative technologies (for more on these comparisons, see Chapter 16). Although two alternative technologies, biomass and MSW, have the highest variable O&M costs with 5.2 and 5.4 mills per kWh respectively, combustion turbine technologies also have a variable cost of 5 mills per kWh (note that $1=1,000 mills). Note, however, that these variable costs can fluctuate with the cost of fuel, which is a more significant problem with natural gas than it is with coal, uranium, biomass, or MSW. The U.S. natural gas price spikes during the winter of 2000-01, which were almost immediately reflected in power prices, demonstrated this vulnerability of dependence on gas-fired peaking units.

In terms of fixed O&M, geothermal, nuclear, solar thermal, biomass and oil/gas steam rank high with more than $30 per kW (as high as $100 per kW for geothermal). Other than nuclear ($55 per kW), most other conventional technologies have fixed O&M costs less than $25 per kW, and less than $15 for gas-fired facilities. In addition to cost and capacity considerations, using the most efficient equipment is important. Efficiency is measured by the heat rate, which is the ratio of amount of heat energy (measured in Btu's) in fuel used to generate one kWh of electricity. Clearly, the lower the heat rate, the more efficient is the plant as this means less fuel is needed to generate power and hence costs less. The advanced combined-cycle gas-fired power plant is the most efficient type while the conventional combustion turbine is the least efficient among the conventional technologies. As we will see later in this Chapter, heat rate (and the associated concept of spark spread) is a very crucial concept in competitive electricity markets.

Although the costs of alternative technologies have fallen (see Chapter 16), they still are not widely competitive with fossil fuel technologies. As a result, the most economical options available to electricity suppliers for meeting the demand for electricity over the next 20 years are existing coal plants and new natural gas plants.
In 1995, the average operating cost of coal-fired power plants was 1.8 c per kWh. Only 66% of their maximum potential output was needed to meet the 1996 level of demand. Over the next 20 years, as the demand for electricity grows, the utilization of coal-fired plants is expected to approach 80%. For new capacity additions, the low capital costs and high operating efficiencies of natural-gas-fired combined-cycle plants make them the most economical choice for most uses.

### Heat Rate

![Image of Heat Rate](image)

<table>
<thead>
<tr>
<th>Source</th>
<th>Kyoto Report - 1996 Energy Information Administration</th>
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A factor that may change the role of coal in the future and enhance the increasing share of gas-fired power is the debate about emissions and, in particular, CO2, which is generally accepted to be the main culprit for global warming. Electricity suppliers have a variety of options available for reducing their carbon emissions. The degree to which each of the options is employed will depend on the level of reduction required and the time frame for this reduction to be achieved (i.e., regulations). If a carbon tax strategy and strict time table is pursued by the international agreements and/or local governments, coal-fired generation may suffer. On the other hand, a market-based solution such as emissions trading, which has been successfully used in the U.S. to reduce SO2 emissions, can buy some time for these plants. In either case, gas-fired generation will likely benefit from environmental regulations as it emits less carbon than coal and other fossil fuels.

### Carbon Emissions

![Image of Carbon Emissions](image)

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The Components of Generation Value

The base values that accrue to electricity generation and the effect that these value components have on wholesale power prices are a subject that requires a modified mind set to understand. In the traditional paradigm, where generation and transmission were merely guarantors of reliable service, these value components were largely ignored or not understood at all. In the competitive marketplace, electricity generation has three main components of value: commodity, optionality, and deliverability.

<table>
<thead>
<tr>
<th>Commodity</th>
<th>Optionality</th>
<th>Deliverability</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conversion of fuel to electricity</td>
<td>Electricity values vary by time and duration of delivery</td>
<td>Greater value by packaging, time, flexibility</td>
</tr>
<tr>
<td>Principal value in regulated environment</td>
<td>Operating characteristics: ramp rates, turnaround capability, fuel switching, peaking</td>
<td>Major feature in deregulated markets</td>
</tr>
<tr>
<td>Not important in regulated environment as market is known</td>
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</tbody>
</table>

Generally speaking, the commodity aspect is the only value that is attached to generation in a regulated environment. The commodity component refers to the ability of a power plant to convert a form of energy - be it fossil or nuclear fuel, wind, water, or sunlight - to another: electricity. The value of this conversion capability is embedded in the economics. With the introduction of competition, the optionality that accrues to a form of electricity generation has become a significant value component. The economies of scale that were the rage in the 1970s and early 1980s have yielded the premium value perched to the generating capacity that has the most opportunity to run at peak periods, and not run at periods of low demand. Rapid ramp rates, complete turn-down capability, storage capacity, and other forms of enhanced optionality add tremendous value to the generation proposition.

The third component – deliverability - is in some ways another form of optionality. The value of the deliverability of power depends on its ability to be packaged in intermittent delivery blocks and for very short periods of time. The other aspect of deliverability is its flexibility in reaching multiple markets are more valuable because they are capable of delivering their output to premium markets on short notice as market conditions change. The price of natural gas fuel is likely to be the most volatile number–next to power prices - to which a merchant generator will be exposed. Therefore, it is critical that IPPs keep close tabs on the prevailing market price of gas, in addition to performing rigorous fundamental supply/ demand balance analyses for informing their fuel-purchase decisions. The level of analytical sophistication and trading acumen should be a function of the company's desired trading activity levels.

### Gas and Power Prices and Optionality

In the U.S. there are several price indexes for both electricity and natural gas; Henry Hub (HH) natural gas and Palo Verde (PV) electricity futures (the latter does not trade any longer) are used here to illustrate the relationship between gas and electricity prices (see chart below). Due to electricity market restructuring, electricity prices are becoming more sensitive to the short-term spot price changes in natural gas and the volatility associated with it. Clearly, electricity and gas prices are positively correlated (correlation coefficient is 0.70).

<table>
<thead>
<tr>
<th>Natural Gas and Electric Power Prices</th>
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<tbody>
<tr>
<td><img src="image" alt="Graph of Natural Gas and Electric Power Prices" /></td>
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</tbody>
</table>

### Merchant Power Plants

Electricity restructuring has done more than just bring competition to the U.S. retail electricity markets. It has also made wholesale power prices more volatile. That volatility is most evident when there are short-term dislocations of supply. The resulting price spikes lead to substantial "risk premiums" in forward power markets. In the past, traditional utilities typically considered their power plants mere collections of brick and mortar. But today, a merchant plant operator increasingly views his facility as a stack of conversion options or options on the available spark spread. But whether the merchant plant operator is a utility or an IPP, competition requires that it makes every possible effort to extract maximum value from the generation portfolio, and that means using sophisticated tools to manage market risk. These risk-management tools are designed to cope with the uncertainties of the new business model that deregulation has ushered in - the Forward Risk Premiums model. As was the case under the old Economic Dispatch model, some portion of forward power prices is still determined by marginal generation economics. Now, however, whenever one or more links in the electricity delivery chain are stressed, the market adds a risk premium to power prices to reflect the uncertainties of forward delivery. Exploiting the existence of that risk premium is the objective of a new concept for managing merchant plant operations called Total Btu Management.
However, due to natural gas storage and hedging effects, this correlation is delayed. These effects prevented an instantaneous increase in the electricity price when natural gas price climbed to a maximum of $340.29/MWh in December 2000. However, an increase in the price of natural gas stored today may affect the price of electricity that uses this stored natural gas capacity several months down the road. Electricity prices in May 1999 spiked to a maximum of 340.29/MWh. Increase in electricity demand due to weather conditions, shortages in natural gas supply and transmission congestions are also major contributors to this electricity price spike.

Gas-fired generation falls into one of three broad categories: (1) existing, mid-merit, simple-cycle generation; (2) high-efficiency combined-cycle; and (3) peaking plants. Plant characteristics - such as heat rate curves, ramp rates, turndown maximums, startup costs, location, and market load share - must be considered here. In many cases, existing, long-dated transactions must also be taken into account. Decisions about long-term indexed transactions or short-term spot activity should be largely influenced by the financial requirements of earnings levels and variability control. In many cases, financing arrangements require that some portion of a facility be committed to long-term agreements. Upon determining the mix of transaction terms that is appropriate, the facility marketing plan must take into account trade construction.

Virtually all gas-fired plants have some level of load-following optionality that is accompanied by substantial short-term price premiums. The IPP must accurately quantify the option value and be compensated for it accordingly. This can be done either by entering into contracts with sizable options premiums embedded in the price formula or by keeping a portion of the unit's output uncommitted and then selling it hourly as market prices dictate. Where a portfolio of different generation types is involved, a total portfolio approach is adopted to take advantage of the combined flexibility of the generation fleet. Within this element, decisions to run or not run a plant are made. When natural gas prices are extremely volatile, very often shutting down a facility and sending its fuel into the market makes better economic sense than keeping the plant running. During the spring and fall, when generating plant economics are marginal, intermittent operation of facilities based upon daily swings in profitability are most crucial. In addition, basis and pipeline economics of natural gas delivery may dictate operating a less efficient facility to exploit fuel economics on the front end of generation. For example, an older, less efficient facility that is located near a liquidity hub might be substituted for a more efficient plant located up the distribution chain to resell the transportation for a profit.

Example on Optionality

The following example illustrates the economics of natural gas-fired power plants. An IPP must determine whether it is economically feasible to operate each power plant based on calculating the spark spread for each plant in each period and based on comparing the market heat rate to that of each power plant. In addition to the data listed in table below, PV and HH prices charted above as well as futures contract prices for five electricity contracts and HH futures contracts from October 2001 for months covering the range from November 2001 to October 2002 are used.

<table>
<thead>
<tr>
<th>Sample Power Plants vs Peaking Units</th>
<th>Monthly Heat Rate</th>
</tr>
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<tbody>
<tr>
<td>Size (MW)</td>
<td>Variable O&amp;M (Mills per kWh)</td>
</tr>
<tr>
<td>Conventional Combined-Cycle</td>
<td>20</td>
</tr>
<tr>
<td>Advanced Combined-Cycle</td>
<td>10</td>
</tr>
<tr>
<td>Conventional Turbine</td>
<td>6</td>
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</tbody>
</table>

From the data, the spark spread is calculated for each plant to determine the operational periods. Then based on the future contract prices the market heat rate is calculated for all months to determine what markets appear to be most attractive in the future for each of the plants. Spark spread for each plant in each period is calculated using the following equation:

\[
\text{Spark Spread} = \text{Power Price} - (\text{Plant Heat Rate} \times \text{Gas Price})
\]

O&M Cost

Algebraically, the spark spread increases as power price increases and/or the heat rate decreases or gas price or the O&M cost decrease. Clearly, the market prices are the prices of power and natural gas. The higher the price of power (such as during peak periods), the more likely it is for a given plant to run unless the natural gas price is also high in proportion to the power price.

Any of the power plants will operate only if the spark spread is greater than zero and should not run when the spark spread is negative. The calculated spark spread for each power plant for the period between April 1999 and October 2001 are provided below. Note that there are many months during the 1999-99 period where the spark spread has been negative for most of the plants, especially conventional combustion turbine plant (Plant 3), which is the least efficient plant (highest heat rate). There are many months during the 1999-99 period where Plant 3 has been the only plant with a negative spark spread (e.g., July 1999, September 1999-May 1999, etc.). Since May 2000, the beginning of California crisis, all plants have become profitable to run. Note, however, that we used monthly average prices; in any given day, prices (in particular, power prices) will fluctuate and the spark spread can become negative certain times of any given day for any of these plants.

Sparks Spreads

<table>
<thead>
<tr>
<th>Month</th>
<th>Plant 1</th>
<th>Plant 2</th>
<th>Plant 3</th>
<th>Plant 4</th>
</tr>
</thead>
<tbody>
<tr>
<td>May 99</td>
<td>-7.790</td>
<td>-6.035</td>
<td>-16.440</td>
<td>-10.993</td>
</tr>
<tr>
<td>Jul 99</td>
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<td>-6.401</td>
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<tr>
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<td>-7.763</td>
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<tr>
<td>Dec 99</td>
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<td>15.009</td>
<td>-32.127</td>
<td>-23.084</td>
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<tr>
<td>Feb 99</td>
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<td>4.921</td>
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<td>Mar 00</td>
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<td>Jul 00</td>
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</table>
The following table compares the market heat rate to the heat rate of each of the power plant in each period. The market heat rate is calculated as the ratio of the power price to the natural gas price. So, the higher the power price is related to the price of natural gas (which also means that the spark spread will be larger), the higher the heat rate will be and the more likely it is for a plant to run. Note that the values provided below are in Btu per MWh as compared to Btu per kWH values used to describe the plants above.

Highlighted numbers are the periods in which the heat rate of the plant is less than the market heat rate. Roughly speaking, a plant will be profitable if the market heat rate exceeds its own. Note, however, that the decisions based on market heat rate may yield different results (and may not be as accurate) than the decisions based on the spark spread because it ignores the O&M cost for the plant.

For example, Plant 3 (the least efficient) should not have run between September 1998 and May 1999 as shown with a negative spark spread above. However, based on the market heat rate, which ranged between 11 and 14 Btu per MWH during that period, Plant 3’s heat rate of 10.6 indicates that the plant could be run. Clearly, when the market heat rate and plant heat rate are close, O&M costs require closer inspection.

### Market Heat Rate

<table>
<thead>
<tr>
<th>Month</th>
<th>Plant 1</th>
<th>Plant 2</th>
<th>Plant 3</th>
<th>Plant 4</th>
</tr>
</thead>
<tbody>
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<td>6.74</td>
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<tr>
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<td>6.35</td>
<td>10.8</td>
<td>6.74</td>
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<tr>
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<td>11.395</td>
<td>6.35</td>
<td>10.8</td>
<td>6.74</td>
</tr>
<tr>
<td>May-99</td>
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<tr>
<td>Jun-99</td>
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<tr>
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<td>6.74</td>
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<td>6.74</td>
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</tbody>
</table>

A similar analysis can be carried out looking into the future when reliable data on the forward price curve can be obtained. Below, Entergy and Cinergy markets were not expected to have high power prices relative to the price of natural gas and hence Plant 3 and 4 were not expected to run. Again, remember that the market heat rate ignores O&M costs and that daily price fluctuations may also impact the decision of when to run a plant.

### Market Heat Rate in the Future

<table>
<thead>
<tr>
<th>Month</th>
<th>COB</th>
<th>Energy</th>
<th>Cinergy</th>
<th>CCGT</th>
<th>Polo Verde</th>
</tr>
</thead>
<tbody>
<tr>
<td>Nov-99</td>
<td>11.396</td>
<td>7.925</td>
<td>1.510</td>
<td>1.415</td>
<td>11.319</td>
</tr>
<tr>
<td>Jan-00</td>
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<td>1.510</td>
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<td>11.395</td>
<td>7.925</td>
<td>1.510</td>
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<td>Mar-00</td>
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<td>7.925</td>
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<td>1.510</td>
<td>1.415</td>
<td>11.319</td>
</tr>
</tbody>
</table>

Given this model and the input values summarized in table above, the plant will generate an NPV of $47 million over 22 years with an IRR of 15% (see table below). Naturally, these values are very sensitive to gas and power prices. For example, if the gas cost rises to $2.9/MMBtu or the power price is down to $.036/kWh, the NPV becomes negative. If both of these events occur simultaneously, the results will naturally be worse. This clearly shows the importance of long-term gas contracts and power purchase agreements the IPPs usually ask for, especially in markets where price forecasts and/or supply and demand conditions for either power or gas or both are not dependable. On the other hand, increasing load factor or efficiency by 4%, or a combination of both would overcome the increase in the cost of natural gas or the decrease in power prices.
10,600 Btu/kWh). Even with mostly lower cost, significantly lower efficiency causes the NPV to be almost zero. If this plant had the same efficiency as our first plant (i.e., 49%), the lower costs would have resulted in an NPV of $74 million and an IRR of 21% (under the same gas and power prices).

Combined Cycle Gas Turbine Economics

<table>
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<th>Year</th>
<th>NPV</th>
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</tr>
</thead>
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<td>-150</td>
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<tr>
<td>2</td>
<td>67</td>
<td>20</td>
</tr>
<tr>
<td>3</td>
<td>0</td>
<td>90</td>
</tr>
<tr>
<td>4</td>
<td>28</td>
<td>80</td>
</tr>
<tr>
<td>Total</td>
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</table>

Relevant Case Studies:
- Brazil Power Market Crisis
- Convergence Merger
- Electricity Restructuring in California

CHAPTER 15
ENERGY TRADING AND RISK MANAGEMENT: STORY OF EVOLUTION

The phrase “energy marketing,” by its very nature, involves the rationalization and evaluation of all energy sources by various parties (the electric utility, natural gas utility, independent power producer, cogenerator, end user, etc.) to determine the best overall fit in attending to customer needs. The commodity itself – energy – is basically becoming a secondary concern to most stakeholders as needs themselves become primary in the choice of which type or types of energy will be utilized. The market itself, in many instances, will help to determine the source from which energy is produced.

Energy customers, once thought of as a captive audience due to the monopoly position of their energy supplier, can no longer be held captive. Most customers have come to appreciate the opportunity to choose their energy suppliers. The larger a customer is, the more likely it is that she will benefit from having a choice. Not only do energy customers desire the opportunity to make choices about their providers, but also they are requiring their supplier or suppliers to assist them in addressing their energy needs. Again, this is particularly the case for large industrial and commercial consumers of energy. However sometime in the future, residential consumers also may be seeking help in addressing their energy needs. This spells out the need for energy marketers to be solution providers and not just merely a provider that offers the best prices.

Evolution in the Energy Industry

Like most all other industries, the energy industry in its current state is the product of evolution – a gradual, yet continual state of advancement brought about through various events. Evolution by its very nature, context, and definition, is ongoing. It never ends. It is constant. A series of historical events has actually caused the industry to evolve and to change into something else. Outside forces, including regulatory policy and, in no lesser part, the economy are direct agents in causing the power industry change. We provided details of the evolution in each of the oil, natural gas and electric power restructuring in chapters 3-5. Here we revisit natural gas and electric power restructuring efforts in the U.S., which set the stage for energy marketing, trading and risk management to mature.

The evolution of the natural gas industry

Natural gas industry restructuring began in 1978, with the passage of the Natural Gas Policy Act (NGPA), which started the deregulation of wellhead price controls. Federal Energy Regulatory Commission (FERC) issued Order 436 in 1985 to help address and control the apparent discriminatory access to pipeline transportation. The courts later would not completely disagree with the purpose of the order, but would, however, have some differences of opinion on how to address the discriminatory access dilemma.

The second major step was the passage of FERC Order 451, which effectively removed vintage price tiers that had been set out under the NGPA. With this order, FERC raised ceilings of vintage gas categories to market levels and established procedures that encouraged procedures and pipelines to renegotiate associated contracts. Due to some legal challenges that faced FERC Order 436, it was reentered as FERC Order 500. This rule would later be finalized and be renamed FERC Order 636, which became the gas industry’s ticket to competition.

The evolution of the electric utility industry

Regulators in the United States are playing a central role in the movement towards a competitive electric power generation market. Driven by the desire to reduce energy prices and to substitute competition for the industry’s traditional monopoly style regulation and the more existing regulated monopolies in transmission and distribution;
- Mesh competitive electricity-generation markets with the and
- Provide an equitable and effective transition between the industry’s traditional monopoly style regulation and the more limited regulation envisaged for the future.

Regulators are still in charge of setting the rules of the game and the competitive opportunities for market participants remain very much in affected by their choices.

The regulatory structure

Investor-owned electricity utilities are subject to economic regulation by the U.S. federal government and by state governments. FERC regulates the rates, terms, and conditions of wholesale sales and transmission of electricity by investor-owned utilities pursuant to the Federal Power Act (FPA). Under the FPA, such rates, terms, and conditions must be “just and reasonable” and not “unduly discriminatory or preferential.” Historically, regulation has been based on the principle of “cost-of-service”—i.e., it was designed to allow the industry to recover its costs plus a fair rate of return (see information on rate making at the end of this workbook).
FERC also regulates certain corporate activities of public utilities, such as mergers between, and acquisitions of, public utilities and the issuance of securities by certain public utilities. According to FPA, FERC must find that a merger or conversion of a public utility will not prejudice the public interests. The dispositions of public utility facilities is consistent with the public interest before authorizing the transaction. FPA also requires public utilities whose securities are not registered under the Securities Exchange Act of 1934 (the Securities Act) to obtain authorization from FERC for the issuance of any security or for the assumption of any obligations as a guarantor of securities.

The FPA also requires that any person who wishes to export electricity from the U.S. should obtain an order from FERC. This power has been delegated to the Department of Energy (DOE), which until recently only granted export authorization for specified transactions if it had been shown that they would not impair the reliability of the affected utilities. In 1994, however, Congress directed FERC to support authorizations for such power exports. Such authorizations require that all necessary contractual approvals be obtained for the use of cross-border transmission facilities and that deliveries using such facilities do not exceed authorized levels.

PUHCA

The Public Utility Holding Company Act or PUHCA came into being in 1935 when Congress decided that it was time to restrain the activities and dealings of large holding companies in both the natural gas industry and in the electric power industry. The goal of PUHCA was to simplify and regulate the organization of holding companies and to limit the geographic size of utilities. The act gives the Securities and Exchange Commission (SEC) the authority over companies who hold interests in public utilities and operations of registered public utility holding companies. Under PUHCA, the SEC scrutinizes virtually every significant undertaking undertaken by registered holding companies, as well as their accounting practices and corporate structures. In fact, SEC oversees all the corporate entities in a given public utility holding company system.

To avoid regulation under PUHCA, holding companies must obtain an exemption under one of five categories, the most significant being the exemptions for holding companies that operate predominantly in one state or for holding companies that are predominantly utility companies operating in their state of organization and contiguous states. To bring themselves within these exemptions, most utilities in the U.S. are organized and operate as independent public companies or as small electric power production facilities using renewable energy sources. Also, PURPA encourages plants to cogenerate electricity by using excess steam from various manufacturing processes. Electricity utilities are required to purchase power wholesale from certain types of independent power producers, namely independent power plants that produce electricity with renewable sources (e.g., solar, wind, biomass), or which “cogenerate” (i.e. produce both electricity and another useful form of energy such as steam).

The rates for utility purchases from such entities are determined by state regulatory agencies, but are to be no more than the “avoided cost” of generating electricity by purchasing power from the suppliers. This means that the purchasing utility would have incurred in order to build or acquire the energy and capacity itself. The Act brought scores of new participants into wholesale power markets and utilities had to deal with independent, third-party power suppliers for the first time. In the wake of PURPA, state regulatory commissions also began developing and expanding competitive procurement policies for electricity utilities, resulting in more extensive integrated resource plan requirements.

The underlying principle of PURPA was that utilities would pay no more for electricity than their opportunity cost, but to facilitate the financing of new power plants, state commissions required utilities to enter into long-term power contracts, frequently at fixed rates. As the market has developed, the traditional power structure has been modified or dismantled to allow the movement toward a competitive market and helped create one of the major problems in effecting that change.

FERC issues historic final rules

On April 24, 1996, FERC issued a set of final rules, known as FERC Order No. 888 and FERC Order No. 889, pertaining to electric utility industry restructuring. Order 888, known as the Open Access Same Time Information System (OASIS) rule, allows a utility to provide network transmission service. Under Order 888, public utilities that own, control, or operate transmission lines are now required to file non-discriminatory open access tariffs that offer others the same transmission service they provide themselves. Rates for such transmission services (and for associated ancillary services) are to be determined in individual proceedings before FERC on the basis of the supplying utility’s cost of service.

Order 889 is known as the Open Access Same-time Information System (OASIS) rule. An OASIS is an electronic information system accessible through the Internet. An OASIS system should provide market participants with all the information about a utility's transmission system that they need to make use of a utility’s tariff. OASIS will ensure that transmission owners and their affiliates do not have an unfair competitive advantage in using transmission to sell power. Order 889 also requires utilities to adopt standards of conduct that prohibit the exchange of transmission function and the power marketing arms of utilities have equal access to information about transmission.

Under Orders 888 and 889, a utility must "functionally unbundle" all wholesale sales and purchases of electricity. That is, the utility must separate its generation, transmission, and sale of electricity.

FERAct began what has become a tidal wave of changes in national policies and regulations that have, in the past, defined the role of utilities in the generation, transmission, and sale of electricity.

Under the sections added to the FPA, FERC can order a “transmitting utility” (a category that includes municipal utilities and electric cooperatives in addition to investor-owned or investor-controlled companies) to provide transmission service to others. In a series of orders implementing these provisions, FERC has established a procedure whereby a customer seeking transmission service would make a “good faith request” to the transmitting utility for such service. If such request is not granted, the customer can file a complaint with FERC seeking an order compelling transmission service. FERC may then order the parties to negotiate and, if such negotiations fail, to file briefs with the Commission. The Commission will then decide whether to order such services and their rates, terms, and conditions.

Prior to the EPA, FERC had never required a utility to provide "network" transmission service. Rather, FERC had held that "point-to-point" transmission service was to be provided by utilities. However, in 1994, FERC issued an order requiring a utility to provide network transmission service. Such service was to be priced on the basis of the customer’s “load ratio share” of the transmitting utility’s transmission system costs. In 1994, FERC also made an important conceptual shift and began making its approvals conditional upon the requirement that utility tariffs offer a service that is “comparable” to the “transmission owners’ own use of its transmission system.

Processing individual requests for access was a slow and cumbersome process, generally taking well over a year from the time of the initial request for service to final FERC disposition. To avoid these burdens and to accelerate the process, FERC ordered utilities to submit to FERC a report on their unbundling plans. FERC has approved a rule requiring all public utilities to provide open access. This rule—the watershed Order 888—proved to be the critical step in establishing the framework for competitive wholesale markets. It also laid the foundations for reform at state level intended to bring about a competitive retail service.

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By April 24, 1996, FERC had adopted a series of rules establishing open access for the bulk power market and helping create one of the major problems in effecting that change.

The rates for utility purchases from such entities are determined by state regulatory agencies, but are to be no more than the “avoided cost” of generating electricity by purchasing power from the suppliers. This means that the purchasing utility would have incurred in order to build or acquire the energy and capacity itself. The Act brought scores of new participants into wholesale power markets and utilities had to deal with independent, third-party power suppliers for the first time. In the wake of PURPA, state regulatory commissions also began developing and expanding competitive procurement policies for electricity utilities, resulting in more extensive integrated resource plan requirements.

The underlying principle of PURPA was that utilities would pay no more for the electricity than their opportunity cost, but to facilitate the financing of new power plants, state commissions required utilities to enter into long-term power contracts, frequently at fixed rates. As the market has developed, this traditional power structure has been modified or dismantled to allow the movement toward a competitive market and helped create one of the major problems in effecting that change.

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and has no doubt contributed to the wide acceptance of Order 888 by the industry.

The demands of competition
The passage of the Public Utility Regulatory Policies Act (PURPA) of 1978 unleashed the forces for change in the electric power industry. The advent of diversification processes that generated and sold electricity, but were not integrated utilities, introduced new stakeholders, new ideas and new demands. The first power sales transaction to be crafted by a non-traditional utility was executed in 1986 by the Energy Coast. The energy was sold using market-based pricing rather than the traditional cost-based pricing. In 1989, FERC approved the application of the first industry-wide power marketing company, Citizens Power & Light Corporation, to sell electric power at market-based prices. Pressure for more competitive markets continued to mount, and the Energy Policy Act of 1992 established federal guidelines for opening electricity markets to competition. The ranks of the electricity marketers swelled to more than 250 companies. Inevitably, non-discriminatory access to the electric power transmission service became a key issue, which FERC addressed with Orders 888 and 889.

Relationships between utilities and new entities: The restructured market
The relationships between utilities that existed under traditional regulation were replaced with more complex transmission-related interactions. There are three broad categories of interactions. First of all, marketing interactions between the sellers and buyers of power give rise to the need for a transmission service. The merchant then sets in motion the transmission service interactions by querying the OASIS data system to determine whether transmission services are available and economical. In the necessary transmission to support the proposed transaction. The transmission providers refresh the data on the OASIS and take the transmission reservations over the OASIS. As the hour of delivery approaches, schedules for energy deliveries using the transmission reservations are filled with the transmission provider. This give rise to consideration between generators, loads (i.e., power takers) and other transmission providers, to allow each party to make the deliveries within the constraints of the system.

The traditional utility will continue, in the near term, to serve the loads within its franchise area. However, its generation, transmission, and load enterprises will be “unbundled” into their various functions as the utility responds to the FERC unbundling requirements. Generation enterprises and the load enterprises will eventually need marketers with different sets of skills to sell energy and capacity from generating assets and to buy energy and capacity into the load. Most modern utilities have already created affiliated power marketer enterprises to arrange power transactions beyond their franchise area. In these cases, the affiliated power marketers are obliged by Order 889 to query the same OASIS data as the other merchants to review transmission availability and make reservations. Transmission-dependent utilities continue to serve their native loads, but have a vastly increased opportunity to purchase power from multiple sources.

Many of these opportunities arise from the new market participants. Independent power producers (IPPs) and power marketers are active in the marketplace. Load aggregators and independent transmission enterprises do not yet have a substantial presence, but may evolve as return competitive marketing and independent entities build and operate transmission assets. Independent system operators (ISOs) are being formed to provide independent operation of the transmission grid. In the end, the ISO in a region will probably maintain the OASIS on behalf of transmission providers.

Another new entrant to the power market is the power exchange (PX). In reality, several power exchanges may eventually operate in the marketplace, some trading futures products, some trading physical products, while others are yet to be conceived. To the extent that trading generating transmission requirements, either the PX or its participants must arrange transmission services. The New York Mercantile Exchange (NYMEX) initiated two futures power exchange contracts at the Western Interconnection, one at the California-Oregon Border (COB) hub and the other at the Palo Verde hub in the late 1990s but both contracts were cancelled along with Cinergy contract due to lack of interest and California crisis. As any exchange-based contracts, they were very well defined in terms of quantity, time periods, and the like. As it turned out, this standardization that worked fine for oil, products and natural gas contracts was not desirable for electricity. Many players developed their own products and traded them over the counter.

The final new entrants in the marketplace are the security coordinators (SC), formed in 1997 by North American Electric Reliability Council (NERC) to coordinate the secure and reliable operation of the North American transmission grid. The security coordinators provide standardized interconnection information to the NERC Inter-Regional Security Network (ISN), and receive coordinating instructions from the security coordinators when the transmission networks are under severe stress. The security coordinators also provide standard line-loading relief procedures to relieve the stressed facilities.

Managing Risk in a Competitive Environment
As restructuring of natural gas and electricity markets took effect, prices for these commodities started to become more volatile. Commodity prices are influenced in response to seasonality, in demand, cost conditions, and the like. Natural gas and in particular electricity proved to be much more volatile than most other commodities. Price volatility increases risk for both producers considering their investment plans and consumers planning their energy budgets. Like any other risk, energy price volatility risk needs to be managed.

Risk Management Goals & Strategies
The first step in devising a risk-management policy is to understand that risk management can be different things to different people. There are different kinds of trading strategies, which achieve very different kinds of risk and return goals. Not only can the same firm be following different goals, the firm may actually be practicing strategies that do not necessarily fit the desired goals. There are many different approaches to trading strategies, but they can be broken down into four distinct groups:

• Speculation
• Arbitrage
• Market Maker
• Treasury

While not mutually exclusive, each strategy represents a different balance of risk and return that requires very different types of business processes and management. A manager would be wise to evaluate her own operation, understand how it could be categorized as one or more of the distinct strategies, and perhaps begin the process of separating functions in order to evaluate them.

The figure below plots the four strategies across risk and return. Speculation, arbitrage, and market making are profit-generating strategies, while the treasury strategy is a pure risk-reducing strategy.

Speculation
A speculative trading strategy is typically a large-return-for-large-risk strategy. It is typically very short-term, in terms of holding the positions are held as well as how far out the traded contracts tend to go. This type of strategy benefits from a great deal of liquidity for greater deal turnover and hence more opportunity. Nonetheless, it can also be seen in illiquid markets, where the deals are held for longer periods of time. The traders asked to generate value in such a strategy are primarily market-driven, as they try to guess the short-term market moves.

Arbitrage
An arbitrage strategy involves “beating” the marketplace with one’s ability to value and hedge derivative products. Sometimes this can be pure arbitrage, where value is captured through a zero-risk pure arbitrage market opportunity. Sometimes this can be “statistical arbitrage,” where value is captured by exploiting a market opportunity over a period of time and by doing many trades. The pure arbitrage case is a perfectly hedged value-added deal.

An example can be buying a futures contract at the Chicago Board of Trade and simultaneously selling the exact same contract on the Philadelphia exchange but at a higher price than what it was bought for. Obviously, pure arbitrage opportunities carrying no risk are hard to find, and when they are found they do not last for very long. Statistical arbitrage involves capturing market mispricing, which is obvious only to the players who know something about the market or about product pricing. A good example of such statistical arbitrage occurs when the market is using too low a volatility in pricing options. The risk is typically much smaller than in the case of the spec side strategy. Arbitrage strategies can primarily be found in relatively new and fairly illiquid markets, as these typically provide mispricing opportunities.

Market Maker
Being a risk-management service provider, or market maker, is in theory a zero-risk strategy that captures the bid-ask spread in the marketplace. A market maker is willing to quote a price on almost any deal within a well-defined market-place to its customer. When a customer enters into a deal,
the service provider looks for the best hedges for the deal. If the market is liquid and mature, the service provider can hedge off all the first-order risks. When the hedging is assumed continuous, as the first-order risks change due to the market underlying prices and volatilities changing, the service provider immediately rehedged. In such a way, all the risks are brought down to a minimum at all times.

However, the reality is that even in highly liquid markets hedging is not continuous, and hence the service provider is generally left with some small daily risks. Similarly, the hedging costs may be high enough that the risk manager decides that she is better off keeping some risks on the books rather than paying for the hedges. In the case of an illiquid market, not only is the hedging very far from being continuous, it may also be impossible to hedge off certain types of risk. Hence, in both the liquid and the illiquid markets, being a service provider carries a certain amount of risk. One piece of good news is that the greater the illiquidity in a market place, the greater are bid-ask spreads.

**The Role of Marketers and Brokers**

With the restructuring of the natural gas and electricity industries a group of niche players who offer specialized services came on the scene. From arranging bulk power transactions. There are at least two main differences between a marketer and a broker. First, brokers do not assume financial risk. The role of the broker is to bring together a willing seller and a willing buyer without actually taking title to the power. Marketers actually take title to the power, thus their attractiveness in reducing a utility's financial risk. Secondly, brokers differ from marketers in that they currently are not regulated by FERC.

The ranks of marketers and the total trading volume grew at a fast pace between 1996 and 1998 and remained high until about 2000. The rise in the number of marketers and their transactions at the wholesale level were largely due to their unique ability to offer services that utilities traditionally have not developed. Marketers were able to unbundle and then rebundle differentiated products to meet the needs of a vastly changing market. Through this unbundling and rebundling activity, marketers were able to provide high-impact and high-demand services. In the physical market, marketers were able to provide the following services: system firming, shaping, dispatchability, displacability, and storage. In the financial area, marketers were able to offer the following flexible contracts, flexible pricing, and various financial instruments, such as futures.

These attributes particular to marketers made them highly attractive to utilities that generate electricity and were looking for new, innovative ways to market the power they produce. Utilities that once found themselves having to enter into long-term power purchase contracts were finding that they could go with short-term contracts when they employ the use of marketers. This implied two things: that the contracts were viewed by utilities as safer and second that utilities liked the idea of sharing or relinquishing altogether their financial risk through shifting it to the marketer. Most of these qualities are still true but California and Enron crises and following meltdown in the energy trading business changed the face of the industry. In the table to the left, one can see that volume of natural gas marketed fell by almost 40% between 1999 and 2003. Once high flying trading companies, such as Enron, Aquila, Dynegy, and Duke are not even in the list for 2003. The list is now dominated by companies with real assets and production, such as BP, Sempra, ConocoPhillips, and ChevronTexaco. The picture is similar in the electricity market as well (see table next page). Although the volume fell only by 14%, the composition of traders changed. Again, Enron and Aquila and others like them are replaced by companies with real assets. Part of the decrease in volumes marketed can be explained by the roundtrip trades some of these companies employed before the collapse in 2001-2002.

**Financial market advancements: NYMEX and others**

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There are two different types of marketers: affiliated and independent. Under FERC guidelines, affiliated marketers are comprised of any group that has more than a five-percent or ten-percent ownership by an electric utility, which is defined as an independent power producer. In the late 1990s, there were 365 independent power marketers, 112 power marketers affiliated with utilities and 89 power marketers associated with other power generators.

It must be noted that brokers also carry a significant amount of weight in determining who trades and the total trading volume grew at a fast pace between 1996 and 1998 and remained high until about 2000. The rise in the number of brokers and their transactions at the wholesale level were largely due to their unique ability to offer services that utilities traditionally have not developed. Brokers were able to unbundle and then rebundle differentiated products to meet the needs of a vastly changing market. Through this unbundling and rebundling activity, brokers were able to provide high-impact and high-demand services. In the physical market, brokers were able to provide the following services: system firming, shaping, dispatchability, displacability, and storage. In the financial area, brokers were able to offer the following: flexible contracts, flexible pricing, and various financial instruments, such as futures.

The three major energy futures exchanges are the NYMEX, IPE, and SIMEX (Singapore International Monetary Exchange). For electricity and natural gas, only NYMEX and IPE will be significant. Since starting with heating oil futures in 1978, energy futures and options markets on the New York Mercantile Exchange have grown and profoundly changed energy marketing. Contracts traded on the NYMEX include light sweet crude oil,
unleaded gasoline, New York Harbor #2 heating oil, Henry Hub natural gas, propane, coal and PJM electricity. The sour crude and Gulf Coast gasoline are not actively traded at this time. A residual fuel oil contract is no longer listed. Recently, NYMEX introduced Brent crude oil contract that competes with the well established Brent contract at IPE, which also trades gasoil, and unleaded gasoline futures contracts. The SIMEX trades residual fuel oil (reintroduced in April 1997) and has an inactive gasoil futures contract which may be relaunched in the future. In 1995, the SIMEX listed the IPE’s Brent crude oil futures contract as a mutual offset contract for the Far East, where it trades much smaller volumes compared to London-based Brent trading.

All three established energy futures exchanges have indicated they will continue to launch futures contracts that conceptually hedge the entire barrel of crude oil as it makes its way from the ground to the consumer, as well as natural gas, electricity, and coal contracts. However, most refiners and end users are more comfortable using other over-the-counter financial instruments to hedge less liquid products such as residual fuel oil, jet fuel, naphtha, and diesel fuel.

New Systems in Risk Management

The NYMEX trades options on crude oil, New York Harbor unleaded gasoline, #2 heating oil, and natural gas, providing additional tools to manage price risk. The NYMEX natural gas futures contract, launched on April 3, 1990, has rapidly established itself as an effective instrument for natural gas price discovery in North America. NYMEX launched natural gas options in October 1992, adding another tool to manage risk in that volatile market. A second natural gas futures contract was launched on August 1, 1995, by the Kansas City Board of Trade, which is oriented to the western U.S. market.

In February 1990, the NYMEX initiated long-dated options for the crude oil contract. These options trade 12 months out. Long-dated options were a direct response to the growth of off-exchange markets. They allow users to lock in a fixed price for a range of years and are useful for refining and end users entering into long term supply contracts where crude oil prices are likely to be variable. Since that time, NYMEX has extended the crude oil contract out seven years and its Henry Hub natural gas contract out three years forward. The IPE has been particularly successful with its Brent crude oil options and also a gasoil options contract.

In the last few decades, growing energy demand, increasing environmental problems, and concerns about exhaustibility of fossil fuel resources made the world look to alternative energy options. For many, securing environmentally sound sources of energy is one of the most important global challenges for the future. Governments around the world unilaterally and via international agreements support development of efficient and clean technologies and put their efforts into creating a stable framework for commercial decision-making that will provide further motivation for technological development in order to stimulate environment-friendly choices in the marketplace. Many believe that supplying new technologies can transform fixed environmental problems into development opportunities that will foster economic growth and provide energy security.

The alternative (or emerging) technologies listed above serve by either:

- Prominently increasing energy supplies, thereby increasing energy security (technologies include frontier hydrocarbon technologies such as gasification, including hydrogen production; gas-to-liquids; tar sands, oil sands, and other heavy crude extractive and processing technologies);
- Providing additional non-hydrocarbon supply options (ethanol, biodiesel, wind and solar);
- Moving towards globalizing a regionally limited natural-gas market to reduce risks associated with supply and price (LNG); or
- Reducing emissions of greenhouse gases (new emission-free supplies such as nuclear, wind, solar; more efficient end-use technologies such as hydrogen fuel cells and advanced technology vehicles; reduced emissions from hydrocarbon usage such as coal gasification, cogeneration and deployment of CO2 capture and sequestration technologies and strategies).
To meet projected U.S. energy demand growth of 34% in the next two decades, U.S. oil and gas companies invested $98 billion from 2000 through 2005 on emerging energy technologies. This expenditure is 73% of the estimated total of $135 billion spent by U.S. companies and the Federal government. Of the industry investments, $86 billion (or 88% of the $98 billion total) were directed toward frontier hydrocarbons. In addition, the industry invested $11 billion (or 11% of the $98 billion total) for advanced end-use technologies, mostly for efficiency improvements through combined heat and power (cogeneration) and for advanced-technology vehicles using fuel-cell technology. Significantly, this $11 billion investment in end-use technologies represents 35% of the estimated total amount ($31 billion) spent by U.S. companies and the Federal government in this area.

In addition to the U.S. oil and gas industry, other significant emerging technology investments were made by the motor-vehicle industry, agricultural industry, electric utilities, renewable-fuel industry, and the Federal government. These other private industries are estimated to have invested $32 billion (or 23% of the $135 billion total) from 2000 to 2005. Of the $32 billion, $20 billion (62%) is associated with end-use technologies, $12 billion (37%) with non-hydrocarbons, and $0.3 billion (1%) with frontier hydrocarbons. The five leading technologies for private and public sector investment (see figure below), as measured by expenditure, are gas-to-liquids (30%); tar and oil sands (25%); advanced technology vehicles (19%); liquefied natural gas, or LNG2 (7%); and wind power (4%).

Electric Power Generation

Renewable energy sources, including water, wind, solar, geothermal, and some combustible materials, such as landfill gas, municipal solid waste (MSW), and other forms of biomass, offer a great opportunity for reducing dependence on foreign oil and gas, and reduce the environmental impacts of fossil-fueled electricity generation. Recently Europe, however, has surpassed the U.S., especially in the use of wind power. Worldwide, electricity generation from renewable sources increased from 1.7 quadrillion Btu (quads) in 1990 to 3.8 quads in 2003, or almost 125% (see table below).

There are two main areas for new energy sources and technologies to play a significant role: electric power generation and transportation.

Masterbook of Business and Industry (MBI)
Transportation
Worldwide, on roads today, over 5 million cars, trucks and buses run on something other than gasoline or diesel fuel. A substantial majority (over 1 million) run on liquefied petroleum gas (LPG), a mixture of propane and butane that emits fewer pollutants than gasoline. About 5 million use natural gas in a form of compressed natural gas (CNG) or liquefied natural gas (LNG), around 4 million use ethanol or methanol and about 200,000 are electric cars.

Increasingly, hybrid cars, which use a combination of electric battery and internal combustion engine (ICE), are entering the market. Although they use mostly gasoline and not an alternative fuel, these cars mainly depend on the electric battery and increase the gas mileage to 50 to 60 miles per gallon (mpg) as compared to 25-30 mpg in a typical ICE car. Some alternatives fuels can be largely produced domestically, and may come from renewable energy sources and are not heavy polluters. Stumbling blocks to wider alternative fuel use are a lack of stations that carry the extra fuel tanks or fewer refueling outlets. Only electricity has a suitable infrastructure; however, in many respects, electricity is the alternative fuel most in need of technological improvements in order to be a practical transportation fuel.

Alternative Generation Technologies
The most commonly used types of alternative sources of energy include wind, solar, biomass, hydro, and geothermal. Sections below will describe the characteristics of each type, consider advantages and disadvantages of the use of such resources, as well as the economics of each type.

Hydro
Hydro is the leading source of renewable energy. It provides more than 88% of all electricity generated by renewable sources. Hydroelectric power is an emissions-free, renewable, and mostly reliable source of energy. Hydropower plants take advantage of a virtually infinite source of power. About 20% of all electricity is generated by hydropower worldwide. Hydropower converts kinetic energy from falling water into electricity. By generating carbon-free electricity, hydropower avoids burning fossil fuels and releasing significant amounts of carbon dioxide. Hydropower turbines are capable of converting 90% of available energy into electricity, which makes hydropower power the most efficient form of generation. Even the best fossil fuel power plant is only about 60% efficient.

Although Canada and the U.S. are the two largest producers, Brazil, the third largest, depends on hydropower to generate more than 93% of its electricity, while the U.S gets about 7% and Canada gets about 60% of their electricity from their hydro facilities. Norway produces more than 99% of its electricity from hydropower. New Zealand uses hydropower for 56% of its electricity. Hydroelectric generation increased by 2% in 2003, reflecting rapid growth in Africa, South America and Asia, partially offset by a 0.6% fall in North America and 3.0% decline in Europe.

Wind
Wind power has become the world’s fastest growing electricity generating technology. The world wind energy generating capacity has grown from almost 0 in 1980 to 59,000 MW in 2005, yet still accounting for less than 1% of total world capacity. The increase has been most rapid after 1997.

Global Wind Generation Capacity, 1995-2005

The greatest advantage of wind power is its potential for large-scale electricity generation without emissions of any kind. Recent improvements in technology and better reliability have lowered costs. In addition, government support around the world has been very strong. Wind power plants can be built in small, modular units (less than a megawatt each) within a relatively short time frame, offering power suppliers great flexibility. Capacity factor serves as the most common measure of a wind turbine’s productivity. Estimates of capacity factor of wind farms range from 20% to 40%, as compared to 70-90% for coal and 60-100% for nuclear and 60% for combined cycle gas plant.

The U.S. possessed 95% of the world’s installed capacity in the early 1980s. But by 1990, Denmark, Germany, the Netherlands, and India also developed significant wind capacity, and the U.S. share dropped to 75%. By 2005, Germany was the leading country in generation of wind power. In 2005, the U.S. share was about 16%. But, there have been significant additions in 2005 mainly in Texas and few other states. In many states in the U.S. and elsewhere in the world, electricity restructuring legislation usually calls for the expansion of alternative, or renewable, generation capacity, and wind technology, given its relatively advanced stage and lower costs, benefited the most from these requirements.
sufficient, high temperature water to drive a turbine, and the time a facility can produce electricity. Geothermal energy is a clean energy source. The CO2 emissions from high-temperature geothermal fields used for electricity production are lower compared to other sources. Geothermal generation emits 13 to 380 G/kWh as compared to 453 G/kWh emitted by natural gas, 906 G/kWh by oil and 1,042 G/kWh by coal. As compared to other alternative and renewable sources, geothermal is independent of climate and/or seasons, and can be used 24 hours a day. It can be converted to electric energy, or its heat can be used directly. Electricity generation, and mainly takes place in conventional steam plants and binary plants, depending on the characteristics of the geothermal resource.

The world’s largest geothermal resource region is The Geysers, located about 90 miles northeast of San Francisco in Sonoma and Lake Counties, which has been in operation since 1960 and generates over 1,000 MW, the equivalent of a large nuclear reactor. Currently, geothermal resources are found in 25 countries where around 8,400 MW installed capacity generated about 33 TWh of electricity in 2003 (see Table below). El Salvador, Nicaragua and Iceland together account for about 15% of their electric power from geothermal sources. Although the U.S. is by far the largest in geothermal generation with more than 15 TWh followed by the Philippines at nine TWh and Mexico with almost six TWh, the share of geothermal generation in total is only 0.25% in the U.S. and 2% in Mexico. Another Central American country, Costa Rica generates almost 8% of its electricity from geothermal facilities and Kenya receives more than 5% of its electricity from its geothermal resources. 

Cumulative Installed Geothermal Power Capacity at year-end *(Megawatts)

| Year | Argentina | Austria | Australia | China | Costa Rica | El Salvador | Fiji | France (Gravelines) | Germany | Guatemala | Iceland | Indonesia | Italy | Japan | Kenya | Malaysia | Philippines | Portugal (The Azores) | Romania (Kaharu) | Thailand | Turkey | USA | TOTAL WORLD |
|------|-----------|---------|-----------|-------|-----------|------------|------|-------------------|---------|-----------|--------|-----------|------|-------|------|----------|------------|-------------------|-----------------|----------|--------|------|-------|---------|
| 1990 | 0.0       | 0.0     | 0.0       | 0.0   | 0.0       | 0.0        | 0.0  | 0.0               | 0.0     | 0.0       | 0.0    | 0.0       | 0.0  | 0.0   | 0.0  | 0.0      | 0.0        | 0.0               | 0.0             | 0.0      | 0.0    | 0.0  | 0.0   | 0.0     |
| 1995 | 0.0       | 0.0     | 0.0       | 0.0   | 0.0       | 0.0        | 0.0  | 0.0               | 0.0     | 0.0       | 0.0    | 0.0       | 0.0  | 0.0   | 0.0  | 0.0      | 0.0        | 0.0               | 0.0             | 0.0      | 0.0    | 0.0  | 0.0   | 0.0     |
| 2000 | 0.0       | 0.0     | 0.0       | 0.0   | 0.0       | 0.0        | 0.0  | 0.0               | 0.0     | 0.0       | 0.0    | 0.0       | 0.0  | 0.0   | 0.0  | 0.0      | 0.0        | 0.0               | 0.0             | 0.0      | 0.0    | 0.0  | 0.0   | 0.0     |
| 2003 | 0.0       | 0.0     | 0.0       | 0.0   | 0.0       | 0.0        | 0.0  | 0.0               | 0.0     | 0.0       | 0.0    | 0.0       | 0.0  | 0.0   | 0.0  | 0.0      | 0.0        | 0.0               | 0.0             | 0.0      | 0.0    | 0.0  | 0.0   | 0.0     |
| 2005 | 0.0       | 0.0     | 0.0       | 0.0   | 0.0       | 0.0        | 0.0  | 0.0               | 0.0     | 0.0       | 0.0    | 0.0       | 0.0  | 0.0   | 0.0  | 0.0      | 0.0        | 0.0               | 0.0             | 0.0      | 0.0    | 0.0  | 0.0   | 0.0     |

Alternative Transportation Technologies and Fuels

These are alternative fuels that are being used today for transportation purposes, in place of gasoline and diesel fuel derived from crude oil. The major types of these "alternative fuels" are: liquefied petroleum gas (LPG) and propane, natural gas, ethanol, methanol, electricity, hydrogen, biodiesel, and p-series/L-series fuels. Alternative fuels have two non-economic advantages - they produce lower emissions and can help reduce dependence on imported petroleum.

LPG (or Propane).

When speaking of alternative fuels, the terms LPG and propane are often used interchangeably. LPG for vehicular use is a mixture containing at least 90% propane, 2.5% butane and higher hydrocarbons, and a balance of ethane and propylene. Propane is a by-product of natural gas processing and petroleum refining. It is used at room temperature before it burns in the engine. Of all the alternative fuel types, propane has the largest percentage of converted vehicles. In addition, vehicle manufacturers are committed to producing smokeless, propane vehicles. These factors point to steady, but slow, growth in the use of propane vehicles. Propane was introduced in the early 1900s. It is now a leading alternative vehicle fuel
and is used in over four million over-the-road vehicles around the world. The U.S. is the largest LPG producer in the world. Over 95% of consumed propane in the U.S. is produced domestically.

Compressed Natural Gas (CNG)

CNG is natural gas that is stored in pressurized tanks and used as vehicle fuel. CNG releases one-tenth as much of the pollutants such as CO and NOX as does gasoline. In the U.S., state and city governments began encouraging public and private bus and truck fleets to switch to CNG from diesel fuel. A few cars have run on CNG for a short time, but so far, CNG's use has been limited to buses. CNG can power vehicles because it must be stored in bulky tanks. Cars that run on CNG cost about $3,000 more than gasoline-powered cars. In 2001, about 1,250 U.S. service stations sold the fuel as compared to 900 in 1994.

Ethanol

Ethanol is ethyl alcohol, a grain alcohol mixed with gasoline and sold in a blend called gasohol. Certain crops, such as corn and sugar cane, are fermented to make ethanol. Some studies have shown that ethanol emits less CO and fewer hydrocarbons than pure gasoline.

Methanol

Methanol can be manufactured from a variety of carbon-based feedstock such as natural gas, coal, and biomass (e.g., wood). Methanol is produced from natural gas in production plants with 60% total energy efficiency. The use of methanol diversifies the fuel supply and reduces dependence on imported petroleum. Methanol is transferred from import terminals or production facilities by barges, rail or trucks. Methanol is predominantly produced by steam reforming of natural gas to create a synthesis gas, which is then fed to a reactor vessel for vessel catalysis to produce methanol and water vapor. Although a variety of feedstock other than natural gas can and have been used, today's economics favor natural gas.

Electricity

Electricity is unique among the alternative fuels in that mechanical power is derived directly from it, whereas the other alternative fuels release stored chemical energy through combustion to provide mechanical power. Motive power is produced from electricity by an electric motor. Electricity used to power vehicles is commonly provided by batteries, but fuel cells are also being explored. Unlike batteries, which are storage devices, fuel cells convert chemical energy to electricity.

Electric cars have been on the U.S. roads since the late 1800s, but they became largely extinct when gas-powered cars became the norm because of their considerable disadvantages. The primary attraction of electric cars is that they do not emit pollutants. Their main problems, however, are power storage and vehicle range. Electric cars must recharge their batteries every 90 miles or so. Also, in addition to paying a sticker price up to three times that of a conventional car, electric car owners must buy a recharging system for between $3,000 and $5,000.

In December 1996, General Motors Corp. introduced the first mass-produced electric car, the EV1, in California and Arizona, which failed to establish a market for itself. Great Britain has the most electric cars on its roads — about 25,000. Hybrid cars, however, are more readily accepted by the public. They also depend mostly on electricity to run but since they are also equipped with an ICE, the problems associated with pure electric vehicles such as the limited travel distance between each charge and low performance in tougher road conditions are overcome.

Hydrogen

Although hydrogen can fuel an engine directly, or serve as a fuel additive, the current emphasis is on the use of hydrogen to supply fuel cells, which power electric vehicles. Hydrogen has also been blended with methane to form a fuel called Hythane.

Biodiesel

Biodiesel is another alternative fuel which contains no petroleum but can be blended to any level with petroleum diesel to create a biodiesel blend. Biodiesel can be used in diesel engines with no major modifications.

P-Series

Pure Energy Corporation’s P-series fuels are blends of ethanol, methanol (methyl alcohol), hydroxy fuel (HFO), and pentanes plus with butane added for blends that would be used in severe cold-weather conditions to meet cold start requirements. It is anticipated that both the ethanol and the MTHF will be derived from renewable resources, such as waste cellulose biomass that can be derived from waste paper, agricultural waste and urban/industrial wood waste.

Solar

Solar energy technologies use sunlight to produce heat and electricity. Electric power production from photovoltaic (solar photovoltaic) technologies can be used in conventional electric vehicles. In order to collect this energy and use it to fuel a vehicle, photovoltaic cells are used. Pure solar energy is 100% renewable and a vehicle run on this fuel emits no emissions. Solar vehicles are not available to the general public. Using solar energy directly to power vehicles has been investigated primarily for competition and demonstration vehicles.

Economics of Alternative Generation Technologies

Renewable energy sources and technologies making use of them are very diverse. However, their common tendency is to cost more than conventional technologies but to offer some attractive characteristics, especially in terms of the environmental impact. The balance between relative costs and desired attributes defines the place of each renewable in the portfolio of energy options. All forms of alternative energy are always affected economically by oil prices. When oil prices are low, the alternative energy becomes less desired and oil prices increase, they become more viable and attractive. During the 1970’s oil embargo, the industrialized world encouraged alternative technologies and fuels. As a result, solar power plants flourished and many new hydroelectric, wind, and nuclear plants were built.

Alternative technologies are generally characterized by relatively high capital costs and low operation and maintenance costs, making them attractive in the long run, but less so in a competitive setting where the profitability is on near-minimal level. Advances in conventional power plants continue to lower their cost and increase their efficiency, but outside of small niche markets, they still are not economically competitive compared to conventional sources of power. A comparison of cost and performance of most advanced alternative technologies, including emissions and efficiency (heat rate), to more conventional technologies of power generation is provided below.

The cheapest of the alternative technologies in terms of capital cost is wind with $965 per kW capacity. Note, however, that this level is reached after some economies of scale are established in the production of wind turbines. This capital cost is fairly competitive with coal and nuclear plants, but it is significantly larger (more than twice as expensive) than the cost of most modern gas-fired plants, which is the biggest challenge for all alternative technologies. Natural gas resources all around the world is best utilized in power generation. Low cost of gas-fired generation and relatively low level of capital intensive of these plants are increasing the attractiveness of gas-fired plants (see Chapters 1 and 9 for details).

2002 Overnight Capital Cost (including Contingencies) and Performance Characteristics of Different Generating Technologies

<table>
<thead>
<tr>
<th>Technology</th>
<th>Capital Costs* (2002 $s/KW/hr)</th>
<th>2002 Heat Rates (Btu/KW/hr)</th>
<th>Online Year**</th>
</tr>
</thead>
<tbody>
<tr>
<td>Advanced Combustion Turbine</td>
<td>470</td>
<td>1,550</td>
<td>2004</td>
</tr>
<tr>
<td>Conventional Combustion</td>
<td>495</td>
<td>1,470</td>
<td>2004</td>
</tr>
<tr>
<td>Advanced Gas/Oil Combined</td>
<td>670</td>
<td>7,000</td>
<td>2005</td>
</tr>
<tr>
<td>Conventional Gas/Oil Combined</td>
<td>535</td>
<td>7,500</td>
<td>2005</td>
</tr>
<tr>
<td>Scribed Oil Well</td>
<td>1,154</td>
<td>9,000</td>
<td>2006</td>
</tr>
<tr>
<td>Integrated Gas Combined</td>
<td>1,367</td>
<td>10,000</td>
<td>2006</td>
</tr>
<tr>
<td>Fuel Cells</td>
<td>2,117</td>
<td>10,400</td>
<td>2007</td>
</tr>
<tr>
<td>Advanced Nuclear</td>
<td>2,117</td>
<td>10,400</td>
<td>2007</td>
</tr>
<tr>
<td>Biomass</td>
<td>1,700</td>
<td>9,911</td>
<td>2008</td>
</tr>
<tr>
<td>Solar Thermal</td>
<td>2,941</td>
<td>10,280</td>
<td>2005</td>
</tr>
<tr>
<td>Solar Photovoltaic</td>
<td>3,051</td>
<td>10,280</td>
<td>2004</td>
</tr>
<tr>
<td>Wind</td>
<td>1,093</td>
<td>10,280</td>
<td>2005</td>
</tr>
</tbody>
</table>

*Overtime capital cost includes contingency factors, and excludes regional motivations and learning effects. Interest charges are also excluded. These represent costs of new projects initiated in 2002.

**Online year represents the first year that a new unit could be completed, given a lead time of 2002.

Capital costs associated with other alternative technologies are very high, ranging from $1,736 per kW for Biodiesel (which is barely competitive with nuclear) to $5,289 for Solar Photovoltaic. Although fuel is free for most of these technologies and hence the variable O&M is mostly negligible, fixed O&M costs can also be very high. Even with wind fixed O&M costs reduces the competitiveness of this technology against almost all of the conventional technologies. When determining the fuel source for a new generation plant, it is important to study the "levelized" cost to determine which technology and energy source will be the least costly. Levelized costing considers all capital (capital costs are amortized over the expected power output for the life of the plant), fuel and operating and maintenance costs. Public authorities and energy planners tend to assess different energy sources on the basis of the levelized cost. These calculations do not depend upon variables such as inflation or taxation system. However, the perspective of private investors or utilities is different, and takes into account the variables introduced by government policy and shifts in financial and foreign exchange markets. These investors make decisions on project cash flows and payback time.

Hydro Power

Hydro power has many other renewable resource options, hydropower, in particular, has certain advantages and disadvantages. However, it is important to support engineering of the systems to combine it with other renewables so that this resource is captured and stored, e.g., as...
hydrogen. Turbines, turbine generators, and turbine control systems, which are now under development, represent a step toward the efficient models to be used in 2030.

The key factors relevant to the economics of a hydro development are:

- Initial capital outlay
- List lifetime for the scheme
- High reliability and availability
- Low running costs
- No annual fuel costs

The cost of generation by existing large-scale schemes is estimated to be $0.75-0.90/kWh, calculated on an historic costing basis. For small-scale schemes, in general the initial costs are lowest for sites with high hydraulic heads. These costs increase as the hydraulic head decreases, while scheme viability decreases as generating capacity decreases. The initial costs are, though, very dependent on the details of a particular scheme. Land prices and rents vary according to local circumstances. If existing engineering structures are used, capital costs can be considerably reduced.

Wind

There are two main influences which affect the cost of electricity generated from the wind, and therefore its final price: technical factors, such as wind speed and the nature of the turbines (the windiness of the site, wind turbine availability, and the way the turbines arranged so that they do not interfere with each other), and the financial perspective of those that commission the projects, e.g. what rate of return is required on the capital, and the length of time over which the capital is repaid. Annual electricity production will vary enormously depending on the amount of wind on the turbine site. Therefore, there is not a single price for wind energy, but a range of prices, depending on wind speeds.

Wind power is currently a viable technology under ideal site conditions, and rapid advancements in technology will enable the growth and deployment of wind power to more marginal geographic areas, using significantly less land resources. Wind energy generation is expected to increase in efficiency and become a significant source of power by 2030. The technical focus will be turbines and systems.

With wind energy, and many other renewables, the fuel is free. Therefore once the project has been paid for, the only costs are operation and maintenance and fixed costs, such as land rental. The capital cost is high, between 75% and 90% of the total.

Public authorities and energy planners require the capital to be paid off over the technical lifetime of the wind turbine, i.e. 20 years, whereas the private investor would have to recover the cost of the turbines sooner or during the length of the bank loan. The interest rates used by public authorities and energy planners would typically be lower than those used by private investors.

The economics of wind energy are already strong, despite the relative youth of the industry. Although the cost varies between different countries, the trend everywhere is the same - wind energy is getting cheaper. Power production costs for wind turbines have dropped 80% since the early 1980s and now costs of generating electricity from the wind falls somewhere between $4-6 per kWh. Prices are projected to drop another 20 to 40% over the next ten years. The cost is coming down for various reasons. The turbines themselves are getting cheaper as technology improves and the components can be made more economically. The productivity of these newer designs is also better, so more electricity is produced from more cost-effective turbines. There is also a trend towards larger machines. This reduces infrastructure costs, as fewer turbines are needed for the same output.

Capital Cost of Wind Power

The cost of financing such capital intensive energy as wind energy is also falling as lenders gain confidence in the technology that have steadily progressed to a higher reliability level. However, capital costs remain high compared to other gas-based technologies. Combined with problems of intermittency, lack of storage, cost of connecting to the grid and so on, these high costs makes financing of wind projects a challenge without some kind of public sector support.
A typical existing coal-fueled power plant produces power for about 4¢/kWh. Co-firing inexpensive biomass fuels can reduce this cost to 2.1¢/kWh. In today's direct-fired biomass power plants, generation costs are about 9¢/kWh. In the future, advanced technologies such as gasification-based systems could generate power for as little as 5¢/kWh. For comparison, a new combined-cycle power plant using natural gas can generate electricity for about 4 to 5¢/kWh.

For biomass to be economical as a power plant fuel, transportation distance from the resource supply to the power generation point must be minimized, with the maximum economically feasible distance being less than 100 miles. The most economical conditions exist when the energy use is local, as is the case when the biomass residue is generated (i.e., at a paper mill, sawmill, or sugar mill). Modular BioPower generation technologies under development by the U.S. Department of Energy and industry partners will minimize fuel transportation distances by locating small-scale power plants at biomass supply sites.

**Economics of Alternative Transportation Technologies and Fuels**

There is a cost premium for each alternative transportation technologies over the ICE. In the case of ethanol, the fuel is also more expensive. In terms of mileage, only LPG and electricity offer more miles per gallon. Although maintenance costs can be lower for some (e.g., CNG and LPG), none of the fuels appear to offer an absolute advantage over the ICE and gasoline when all of the factors in the table are considered.

<table>
<thead>
<tr>
<th>Range (compared to Current ICE)</th>
<th>CNG</th>
<th>LPG</th>
<th>Ethanol</th>
<th>Electricity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Power cost compared to gasoline</td>
<td>(0°-20%)</td>
<td>equal or greater</td>
<td>(0°-20%)</td>
<td>equal or greater</td>
</tr>
<tr>
<td>Maintenance costs life</td>
<td>slightly longer</td>
<td>equal</td>
<td>longer life</td>
<td>equal</td>
</tr>
<tr>
<td>Vehicle maintenance life</td>
<td>slightly longer</td>
<td>equal</td>
<td>longer life</td>
<td>equal</td>
</tr>
<tr>
<td>Cost of ownership</td>
<td>$2,700 to $3,000</td>
<td>$1,000 to $2,000</td>
<td>$0 to $1,000</td>
<td>$0 to $1,000</td>
</tr>
</tbody>
</table>
| LPG/Propane Vehicle and costs remain barriers to propane's widespread use as an alternative fuel. Many propane vehicles are conversions, with conversion costs typically ranging between $1,000-$2,000. Retail propane prices were consistent with unleaded gasoline prices during the 1990s, and future propane prices are expected to be less than gasoline. Since propane prices tend to move along with oil prices, however, propane prices can greatly fluctuate.

In 2005, there were an estimated 350,000 on-road propane vehicles in use in the United States. Although that is the largest number among all alternative fuel types, propane vehicles experienced the slowest growth between 1992 and 1998. As a result, propane has lost some of its market share. The greatest concentration of propane vehicles is in the South, where large numbers are operated in the oil-producing States of Oklahoma and Texas.

LPG retail prices are, on average, similar to that of unleaded gasoline prices. Cost averaged $2.56 across the US in September 2005. LPG/propane is used in several different sectors, which makes direct comparison to gasoline at the pump difficult.

**Ethanol**

Ethanol prices are closely tied to commodity prices for agricultural crops. In the U.S., where ethanol is used as an alternative fuel (or as an additive to gasoline to create gasohol), retail prices of ethanol ranged from $2.36-2.83/gallon in late 2005. Ethanol production is more costly on a per volume basis than some other alternative fuels, although government tax incentives of about 25¢/gallon in the U.S., for example, have kept price comparatively low. Ethanol has lower energy content than gasoline; consequently, more fuel is consumed per distance traveled. The price of ethanol is constrained because of corn feedstock, which is closely tied to commodity prices for agricultural crops. For example, severe flooding of the Mississippi River in 1993 directly impacted the corn crop in the Mississippi basin. This flooding resulted in a short-term increase in the regional ethanol fuel price.

**Methanol**

While methanol contains just one-half the energy of gasoline, because the methanol fuel cell car has a calculated fuel economy 1.74-times greater than a gasoline equivalent, the actual cost to the consumer to fuel a methanol fuel cell car is between 60¢ and 77¢/gallon, far less than gasoline-equivalent. At this price, methanol is able to compete quite well with gasoline, and provides a significant return on investment to retailers converting pumps to methanol operation.

In the last few decades, methanol prices, like gasoline, have experienced highs and lows, but on average, methanol is substantially cheaper per gallon than gasoline. Since 1975, the average U.S. wholesale spot price for methanol has been based on a benchmark or index. The average retail costs are about $1.20/gallon. Since it takes roughly 1.65 gallons of M-85 to provide equivalent energy content or range as a gallon of gasoline, the effective cost to the consumer would be $1.87 per gallon.

Given current U.S. gasoline prices well about $3.00 per gallon, this is certainly an attractive alternative for the stationary market. The actual cost to consumers is decreasing in real terms due to economies of scale achieved through the construction of larger, more efficient plants and the distribution of methanol in much larger sea vessels. The repair and maintenance costs of methanol vehicles are similar to gasoline vehicles, with the exception of oil changes except for a special lubricant that is needed. Because the special oil is produced in limited quantities, it is more expensive than regular oil.

**CNG and LNG**

Natural gas can be stored as either compressed (CNG) or liquid form (LNG). As with some vehicle tests have been done using LNG, the development of CNG vehicles is far more advanced. Most of the light-duty CNG vehicles in operation are gasoline vehicles that have been converted to operate on either natural gas or gasoline. Converting a car or light truck for bi-fuel operation can cost anywhere from $2,600 to $3,400 depending on the sophistication of the technology used to meter the natural gas and the number and size of fuel storage tanks. On an energy-equivalent basis, the price of LNG can be higher or lower than gasoline or diesel fuel. The price is very much dependent on geographic location, purity, transportation and quantity. As a substantial majority of the fuel derived from the natural gas, the availability of LNG is expected to decline. This would secure a more affordable LNG refueling infrastructure and could enable economic use of large liquefaction plants.

In 1997, the U.S. federal government revised the excise tax on LNG to approximately 50¢ per LNG gallon, the energy equivalent of gasoline at about 90¢/gal. Excise Provision for LNG use was added. The same rate per gallon as gasoline, with no recognition of LNG's lower energy density. Heavy fuel consuming vehicles over 12,000 lb can pay a flat rate of $168 per year. Without this flat rate incentive, a typical LNG truck using 33,333 gallons of LNG to travel 100,000 miles (at 3 miles per LNG gallon) would pay as much as $2,000 in California State fuel excise taxes for example.

Vehicle maintenance costs are reduced as oil changes are required less frequently and spark plugs last longer. Costs for a "slow fill" system or "quick fill" system to handle pubic or private fleets can cost $900-$2,000 per year or as much as $3 million for a bus fleet. A compressor station typically costs $2,000 to $4,000 per vehicle served. Costs for a compressor for use with a single vehicle in private businesses averages about $3,500. Individual homeowners or compressors use a slow-fill system for overnight refueling. These would usually be located in a home's garage area and would be connected directly to the natural gas supply in the house.

**Hydrogen**

Currently, the cost of hydrogen derived from natural gas is approx $1.2/kg. Hydrogen costs about 50% more than diesel fuel, on a cost per mile basis. When examining the cost of fuel cells, it is necessary to address the vehicle fuel economy. Compared with conventional vehicles, fuel cell powered vehicles have a better fuel economy (they are as efficient as a hybrid). Because the fuel is hydrogen gas, its energy density is much lower than gasoline. These improvements in fuel economy are attributed to the fuel cell power systems. Vehicles equipped with methanol steam reformers are more efficient.

**Electricity**

The operating cost of a vehicle run by electricity depends on vehicle efficiency and the available electric rates. Fueling costs would also be lower especially if off-peak rates are taken advantage of. Recharging an electric vehicle at $0.05 per kilowatt hour (kWh) equates to about $0.015 per mile on average.

Maintenance costs like oil changes are virtually eliminated. Once the relatively high initial capital cost is made, operation costs are much lower in the long term as these vehicles have fewer moving parts to service and replace. There is a significant savings in cost when an electric vehicle is leased rather than bought. Maintenance costs are covered by the lease agreement. As technology improves, buying an electric vehicle may no not be as feasible as the owner may find the technology obsolete after a couple of years. A lease period does not exceed the estimated life of the current technology.

**P-Series fuel**

At commercial scale production, Pure Energy Corporation claims that the price is competitive with that of gasoline. However, commercial production of P-Series fuel is not expected until after 2001, according to Pure Energy Corporation.

**Biodiesel**

The cost of biodiesel is largely dependent on the feedstock, which include soybeans and vegetable oil. A study completed in 2001 by the U.S. Department of Agriculture found that an average annual increase of the equivalent of 200 million gallons of soy-based biodiesel demand would boost total crop cash receipts by $5.2 billion cumulatively by 2010, resulting in an average net farm income increase of $300 million per year. The price for a bushel of soybeans is likely to increase by an average of 17¢ annually during the ten-year period.
Solar
Sunlight is free. The cost involved in using solar energy comes from the cells and the design of systems to make use of energy from these cells. To date, the commercial market for solar powered vehicles is very limited and no solar-powered vehicles have been manufactured with a commercial intent.

Relevant Case Studies
- Brazil Power Market Crisis
- Hospital Power in Congo
- LPG Subsidies in India

GLOSSARY
After-tax cash flow (ATCF) - Earnings after tax plus non-cash charges, such as depreciation and amortization.
Amortization - The systematic allocation of the intangible asset over its useful economic life or some other period of time for financial reporting purposes, tax purposes, or both. (See depreciation)
Business risk - The variability in a company's operating earnings (EBIT)
Capital budgeting - The process of planning for purchases of assets whose cash flows are expected to continue beyond one year.
Capital expenditure - The amount of money spent to purchase a long-term asset, such as a piece of equipment. This cash outlay generally is expected to result in a flow of future cash benefits extending beyond one year in time.
Capital markets - Financial markets in which long-term securities are bought and sold.
Capital rationing - The process of limiting the number of capital expenditure projects because of insufficient funds to finance all projects that otherwise meet the firm's criteria for acceptability or because of a lack of sufficient managerial resources to undertake all otherwise acceptable projects.
Cash flow - The actual amount of cash collected and paid out by a company.
Common pool problem - If a number of producers are extracting oil and gas from a common pool, they each have an incentive to extract as much as they can in order to maximize their revenues.
Common stock - Shares in the ownership of a company. Common stock represents a residual claim on the assets of the company and a right to a portion of the earnings of the company.
Contingent project - A project whose acceptance depends on the adoption of one or more other projects.
Cost of capital - The initial cash outlay required at the beginning of an investment project, often for the purpose of assessing the net present value of net cash flows from an investment project, often for the purpose of assessing the net present value of net cash flows from a project with the present value of the net investment. It is the discount rate that gives the project a net present value equal to zero. The IRR is used to evaluate, rank, and select from among various investment projects.
Discount rate - The rate of interest used in the process of finding present value of a future receipt or series of receipts.
Discounted cash flow - A financial planning tool that models situations where a company expects to receive payments in the future.
Discounted cash flow analysis - A procedure used to evaluate the acceptability of an investment project by comparing the present value of the cash inflows to the present value of the cash outflows.
Dividend - The amount of money paid to the owner of stock in a company.
Economic life of natural resources - The amount of time a resource will last if it is used at its maximum rate.
Expected return - The expected return on an investment is the average return that is expected to be earned on an investment over a period of time.
Expected value - The product of a variable and its probability or the measure of the mean or average value of the possible outcomes. Operationally, it is defined as the weighted average of the possible outcomes with the weights being the probability of occurrence.
Financial analysis - The utilization of a group of analytical techniques, including financial ratio analysis, to determine the strengths, weaknesses, and direction of a company's performance.
Financial forecasting - The projection and estimation of a company's future financial statements.
Fixed costs - Costs that do not vary as the level of a firm's output changes.
Future (terminal) value - The value at some future point in time of a payment (or a series of payments) evaluated at the appropriate interest (growth) rate.
Geologic life of natural resources - Amount of natural resources that is known to exist in the ground and that can be extracted with no consideration of cost (also see Economic Life of Natural Resources).
Hurdle rate - The undiscounted rent of exhaustible resources must rise at the rate of interest (also known as risk cost).
Marketability risk - The ability of an investor to buy and sell an asset (security) quickly and without a significant loss of value.
Net present value (NPV) - The present value of the stream of net cash flows resulting from a project, discounted at the firm's cost of capital, risk-free rate of project's net investment. It is used to evaluate, rank, and select from among various investment projects.
Nominal interest rate - A market rate of interest stated in current, not real (terms. Nominal interest rates reflect expected inflation rates.
Opportunity cost - The rate of return that can be earned on funds if they are invested in the next best alternative investment.
Price elasticity of demand - The percentage change in quantity demanded divided by the percentage change in price. It measures the sensitivity of the quantity demanded to changes in price.
Profit margin - The amount of profit earned on each dollar of sales.
Risk - The difference between the price of a unit of exhaustible resource and the marginal cost of extracting that extra unit - opportunity cost of producing that unit today instead of tomorrow (also see royalty and user cost).
Risk-adjusted discount rate - A discount rate that reflects the risk associated with a particular project. In capital budgeting, a higher risk-adjusted rate is used to discount cash flows for riskier projects, whereas a lower risk-adjusted rate is used to discount cash flows for less risky projects.
Risk-free rate of return - The return required by an investor in a security having no risk of default; equal to the sum of the real rate of return and an inflation risk premium.
Risk premiums - The difference between the required rate of return on a risky investment and the rate of return on a risk-free asset, such as U.S. Treasury bills. Components include maturity risk, default risk, seniority risk, and marketability risk.
Sensitivity analysis - A procedure used to evaluate the impact of changes in the values of input variables on the output of a model.
Simulation - A financial planning tool that models situations where a company expects to receive payments in the future.
Unsystematic risk - Risk that is unique to a company. This also is called diversifiable risk.
User cost - The difference between the price of a unit of exhaustible resource and the marginal cost of extracting that extra unit - opportunity cost of producing that unit today instead of tomorrow (also see royalty and user cost).

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