Petroleum Accounting

Principles, Procedures & Issues

5th Edition

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PREFACE

Petroleum Accounting focuses on United States financial accounting and reporting for petroleum exploration and production activities. This book describes petroleum activities and the numerous accounting principles, practices, and procedures employed in petroleum financial reporting. *Petroleum Accounting* was written to serve as a college textbook and as a reference source for petroleum accountants, financial auditors, and other interested parties.

This 5th edition incorporates much of the 4th edition, adding new chapters to reflect developments in risk management and new accounting for derivatives and the costs to remediate producing properties at the end of their productive lives. No other book contains as much information on petroleum financial accounting.

Authorship. PricewaterhouseCoopers LLP is the U.S. member of PricwaterhouseCoopers, an international professional services firm that provides auditing, tax, and consulting services to many of the world's leading petroleum exploration and production companies. For this edition, PricewaterhouseCoopers partner Dennis Jennings and director Joseph Feiten are the primary authors. They wish to acknowledge and thank Dr. Horace Brock for his instrumental role in the book, particularly as the primary author of the earlier editions, commonly termed in the industry as simply the "Brock Book."

Several PricewaterhouseCoopers partners and staff, alumni, and industry friends have given their assistance and advice for the 4th and 5th editions. Their backgrounds span major operational areas of petroleum exploration and production: senior company management; property acquisition, valuation, and sale; geological and geophysical analysis; reservoir petroleum engineering; production engineering; oil and gas processing; oil and gas marketing; international operations; financial reporting; income tax reporting; and joint venture accounting.

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GLOSSARY

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Chapter One

AN INTRODUCTION TO THE PETROLEUM INDUSTRY

> "As I began my business life as a bookkeeper, I learned to have great respect for figures and facts, no matter how small they were."
>
> John D. Rockefeller, petroleum tycoon and the richest man of his time who gave away over $500 million to charity. Born 1839. Died 1937.

BASIC TERMS AND CONCEPTS

Petroleum refers to crude oil and natural gas or simply oil and gas. These are mixtures of *hydrocarbons* which are molecules, in various shapes and sizes, of hydrogen and carbon atoms found in the small, connected pore spaces of some underground rock formations. These *petroleum reservoirs* are generally thousands of feet below the surface. Crude oil and natural gas are believed to be the remains of plants and animals, mostly small marine life, that lived many millions of years ago.

Oil and gas are discovered and produced through wells drilled down to the reservoirs. An *exploratory well* is one drilled to discover or delineate petroleum reservoirs. A *development well* is one drilled to produce a portion of previously discovered oil and gas. A large producing reservoir may have one or more producing exploratory wells and several producing development wells.

Estimated volumes of recoverable oil and gas within the petroleum reservoir are called *oil and gas reserves*. Reserves are classified as *proved*, *probable*, or *possible*, depending on the likelihood that the estimated volumes can be economically produced.

From petroleum we get numerous useful products:

- *Transportation fuels*, such as gasoline, diesel fuel, jet fuel, compressed natural gas (or CNG) and propane;
- *Heating fuels*, such as propane, liquefied petroleum gas, heating oil, and natural gas burned to heat buildings;

- *Sources of electricity*, such as natural gas and residual fuel oil burned to generate 14 percent of U.S. electricity (with coal, nuclear energy, and renewable sources generating the rest); and
- *Petrochemicals* from which plastics as well as some clothing, building materials, and other diverse products are made.

Different mixtures of hydrocarbons have different uses and different economic values. It is necessary to recognize some basic types of hydrocarbon mixtures to understand portions of this book. *Crude oil* refers to hydrocarbon mixtures produced from underground reservoirs that are liquid at normal atmospheric pressure and temperature. *Natural gas* refers to hydrocarbon mixtures that are not liquid, but gaseous, at normal atmospheric pressure and temperature.

The gas mixtures consist largely of *methane* (the smallest natural hydrocarbon molecule consisting of one carbon atom and four hydrogen atoms). Natural gas usually contains some of the next smallest hydrocarbon molecules commonly found in nature:

Ethane (two carbon, six hydrogen atoms, abbreviated C_2H_6),
Propane (C_5H_8),
Butane ($C_4 H_{10}$), and
Natural gasolines (C_5H_{12} to $C_{10}H_{22}$).

These four types of hydrocarbons are collectively called *natural gas liquids* (abbreviated NGL[1]) which are valuable feedstock for the petrochemical industry. When removed from the natural gas mixture, these larger, heavier molecules become liquid under various combinations of increased pressure and lower temperature. *Liquefied petroleum gas* (abbreviated LPG) usually refers to an NGL mix of primarily propane and butane typically stored in a liquid state under pressure. LPG (alias bottled gas) is the fuel in those pressurized tanks used in portable "gas" barbeque grills. Sometimes the term LPG is used loosely to refer to NGL or propane.

In the United States natural gas is measured in two ways, both important in petroleum accounting:

---

[1]The term *natural gas liquids* is sometimes abbreviated in other publications as NGLs or NGL's. The lighter NGLs (ethane, propane and butane) are gases at normal atmospheric pressure and temperature and are not crude oil. Natural gasolines are liquid at normal atmospheric pressure and temperature and may be called crude oil. Chapter Twenty-Eight explains how reserve disclosures may classify insignificant NGL reserves as crude oil reserves.

- by the amount of energy or heating potential when burned, generally expressed in million British thermal units (abbreviated mmBtu) and
- by volume, generally expressed in
  - *thousand cubic feet* (abbreviated as mcf),
  - *million cubic feet* (abbreviated as mmcf),
  - *billion cubic feet* (abbreviated as bcf), or
  - *trillion cubic feet* (abbreviated as tcf).

In many other parts of the world, gas volumes are measured in cubic meters (kiloliters) and energy is measured in gigajoules. A kiloliter (or cubic meter) approximates 1.31 cubic yards and 35.3 cubic feet. A gigajoule (or a billion joules) approximates 0.95 mmBtu.

Gas volumes are necessarily measured at a standard pressure and temperature, typically at an atmospheric pressure base of 14.65 to 15.025 pounds per square inch absolute (or psia) and a temperature of 60 degrees Fahrenheit.[2]

The ratio of mmBtu (energy) to mcf (volume) varies from approximately 1:1 to 1.3:1. The more natural gas liquids in the gas mixture, the higher the ratio, the greater the energy, and the "richer" or "wetter" the gas.

For various economic reasons, *wet gas* is commonly sent by pipeline to a *gas processing plant* for removal of substantially all natural gas liquids. The NGL are sold. The remaining gas mixture, called *residue gas* or *dry gas*, is over 90 percent methane and is the natural gas burned for home heating, gas fireplaces, and many other uses.

As wet gas is produced to the surface and sent through a mechanical separator near the well, some natural gasolines within the gas condense into a liquid classified as a light crude oil and called *condensate*. Crude oil is measured in the U.S. by volume expressed as *barrels* (abbreviated as bbl).[3] A barrel equates to 42 U.S. gallons. In some other parts of the world, crude oil is measured by weight, such as metric tons, or by volume

---

[2]The typical atmospheric pressure base is 14.65 psia for Texas and Oklahoma production, 15.025 psia for Louisiana production, and 14.73 psia in many other instances. Canadian gas is predominantly from Alberta, which uses the standard international metric system pressure base equivalent to 14.696 psia at 59 degrees Fahrenheit.

[3]Reportedly, the abbreviation bbl arose in the late 1800s when Standard Oil dominated the U.S. petroleum industry and transported crude oil in standardized barrels painted blue. The term blue barrels was abbreviated bbl. Source: *Oil & Gas Journal,* August 14, 1995, page 24.

expressed in kiloliters (equivalent to 6.29 barrels). A metric ton of crude oil approximates 7.33 barrels of crude oil, but the ratio varies since some crude oil mixtures are heavier per barrel than others.

Volumes of crude oil and natural gas combined are often expressed in *barrels of oil equivalent* (abbreviated boe) whereby gas volumes in mcf are converted to barrels on the basis of energy content or sales value. In general, approximately 5.6 mcf of dry gas have the same 5.8 mmBtu energy content as one average U.S. barrel of oil. However, one mcf of gas might be selling for $1.50 when oil is selling for $15 per barrel whereby ten mcf equate to one barrel of oil, based on the given sales prices. For one million boe of gas, the corresponding mcf are shown below for the aforementioned conversion ratios.

Conversion Basis	Assumed Ratio	boe	mcf
Energy	5.6 to 1	1,000,000	5,600,000
Value	10 to 1	1,000,000	10,000,000

Note that many companies use an energy conversion ratio of 6 mcf per barrel, which is the required ratio for certain income tax rules in Internal Revenue Code Section 613A(c)(4).

Crude oil can be many different mixtures of liquid hydrocarbons. Crude oil is classified as light or heavy, depending on the density of the mixture. Density is measured in API gravity as explained in Chapter Eleven. *Heavy crude oil* has more of the longer, larger hydrocarbon molecules and, thus, has greater density than *light crude oil*. Heavy crude oil may be so dense and thick that it is difficult to produce and transport to market. Heavy crude oil is also more expensive to process into valuable products such as gasoline. Consequently, heavy crude oils sell for much less per barrel than light crude oils but weigh more per barrel.

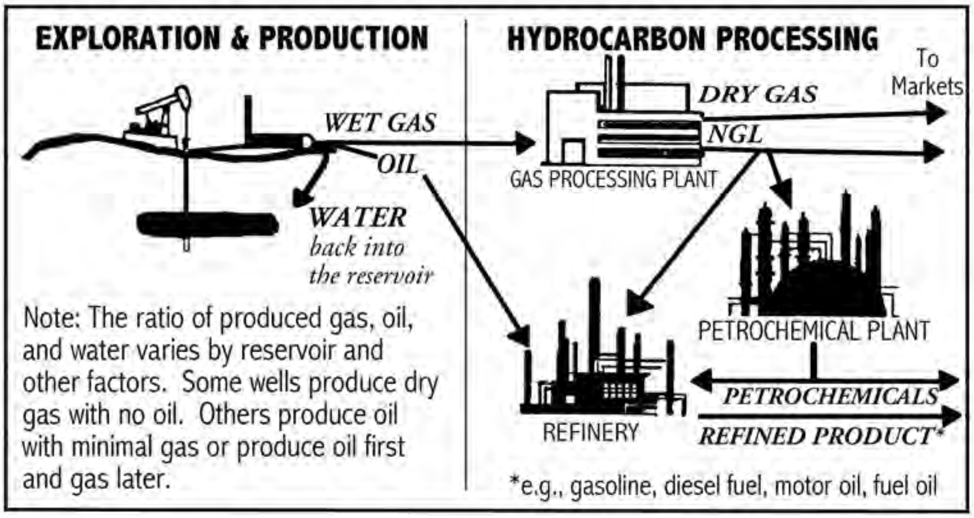
Both natural gas and crude oil may contain contaminants, such as sulphur compounds and carbon dioxide (CO_2), that must be substantially removed before marketing the oil and gas. The contaminant hydrogen sulfide (H_2S) is poisonous and, when dissolved in water, corrosive to metals. Natural gas and crude oil high in sulfur compounds are called *sour gas* and *sour crude oil* as opposed to *sweet* crude oil or *intermediate* (between sour and sweet). Some crude oils contain small amounts of metals that require special equipment for refining the crude.

The *petroleum industry*, commonly referred to as the oil and gas industry, has four major segments:

1. **Exploration and Production**, or E&P, by which petroleum companies (referred to as "oil and gas companies" or simply "oil companies") which explore for underground reservoirs of oil and gas and produce the discovered oil and gas using drilled wells through which the reservoir's oil, gas, and water are brought to the surface and separated (Figure 1-1)
2. **Hydrocarbon Processing** by which crude oil refineries and gas processing plants separate and process the hydrocarbon fluids and gases into various marketable products (Figure 1-1). Refined products and NGL may be processed further in "petrochemical plants" for making petrochemicals. Some petrochemicals may, in turn, be sent to the crude oil refineries for mixing or processing with other liquid hydrocarbons to make various refined products, such as gasoline.
3. **Transportation, Distribution, and Storage** by which petroleum is moved from the producing well areas to the crude oil refineries and gas processing plants. Crude oil is moved by pipeline, truck, barge, or tanker. Natural gas is moved by pipeline. Refined products and natural gas are similarly transported by various means to retail distribution points, such as gasoline stations and home furnaces. In unusual cases, African, South Pacific, and Caribbean countries are exporting natural gas across the oceans and seas by chilling the mixture to a liquid state at -160 degrees centigrade for hauling in special tankers with high pressure, cryogenic containers. This chilled gas is called *liquefied natural gas* (abbreviated LNG).
4. **Retail** or **Marketing** which ultimately markets in various ways the refined products, natural gas liquids, and natural gas to various consumers.

Variations of new, but promising, processes (not illustrated in Figure 1-1) convert natural gas to liquids equivalent to refined product fuels, such as diesel. This *gas-to-liquids* (GTL) approach may enable substantial gas reserves in remote areas to be profitably produced, transported, and sold. Several petroleum companies are conducting pilot tests of such processes.

Figure 1-1: Petroleum Production and Processing Schematic



The E&P segment is sometimes called *upstream* operations, and the other three segments are *downstream* operations. Companies having both upstream and downstream operations are vertically integrated in the petroleum industry and, hence, are called *Integrated*. Other companies involved in upstream only are referred to as *Independents*. The several largest integrated petroleum companies are called *Majors*.

In this book, petroleum accounting focuses on United States generally accepted accounting principles (GAAP) for financial reporting of the exploration and production of petroleum. Chapter Twenty-Five introduces accounting for international operations. Chapters Twenty-Six and Twenty-Seven touch upon accounting for income tax reporting of petroleum exploration and production.

AN OVERVIEW OF PETROLEUM EXPLORATION AND PRODUCTION

Preliminary Exploration. Before an oil company drills for oil, it first evaluates where oil and gas reservoirs might be economically discovered and developed (as explained more fully in Chapter Five).

Leasing the Rights to Find and Produce. When suitable prospects are identified, the oil company determines who (usually a government in international areas) owns rights to any oil and gas in the prospective areas. In the United States, whoever owns "land" usually owns both the surface rights and mineral rights to the land. U.S. landowners may be individuals, corporations, partnerships, trusts, and, of course, governments. A landowner may sell the surface rights and then separately sell (or pass on to heirs) the mineral rights. Whoever owns, (i.e., has title to), the mineral rights negotiates a lease with the oil company for the rights to explore, develop, and produce the oil and gas.

The lease requires the lessee (the oil company), and not the lessor, to pay all exploration, development, and production costs and gives the oil company ownership in a negotiated percentage (often 75 percent to 90 percent) of production. The lessor owns the remaining portion of production. Leasing is explained further in Chapter Seven.

The oil company may choose to form a joint venture with other oil and gas companies to co-own the lease and jointly explore and develop the property as explained in Chapter Ten.

Exploring the Leased Property. To find underground petroleum reservoirs requires drilling exploratory wells (as discussed in Chapter Eight). Exploration is risky; two-thirds of U.S. exploration wells for 1998 were abandoned as *dry holes*, i.e., not commercially productive.[4] *Wildcat wells* are exploratory wells drilled far from producing fields on structures with no prior production. Consequently, 80 to 90 percent of these wells are dry holes. Several dry holes might be drilled on a large lease before an economically producible reservoir is found.

To drill a well, a U.S. oil company typically subcontracts much of the work to a drilling company that owns and operates rigs for drilling wells.

Evaluating and Completing a Well. After a well is drilled to its targeted depth, sophisticated measuring tools are lowered into the hole to help determine the nature, depth, and productive potential of the rock formations encountered. If these recorded measurements, known as *well logs*, along with recovered rock pieces, i.e., *cuttings* and *core samples*, indicate the presence of sufficient oil and gas reserves, then the oil company will elect to spend substantial sums to "complete" the well for safely producing the oil and gas.

Developing the Property. After the reservoir (or field of reservoirs) is found, additional wells may be drilled and surface equipment installed (as explained in Chapters Eight and Eleven) to enable the field to be efficiently and economically produced.

Producing the Property. Oil and gas are produced, separated at the surface, and sold as explained further in Chapters Eleven and Twelve. Any accompanying water production is usually pumped back into the

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[4] American Petroleum Institute's *Joint Association Survey on 1998 Drilling Costs*, p. 21.

reservoir or another nearby underground rock formation (Figure 1-1). Production life varies widely by reservoir. Some U.S. oil and gas reservoirs have produced over 50 years, some for only a few years, and some for only a few days. The rate of production typically declines with time because of the reduction in reservoir pressure from reducing the volume of fluids and gas in the reservoir. Production costs are largely fixed costs independent of the production rate. Eventually, a well's production rate declines to a level at which revenues will no longer cover production costs. Petroleum engineers refer to that level or time as the well's *economic limit*.

Plugging and Abandoning the Financial Property. When a well reaches its economic limit, the well is plugged, i.e., the hole is sealed off at and below the surface, and the surface equipment is removed. Some well and surface equipment can be salvaged for use elsewhere. Plugging and abandonment costs, or *P&A costs*, are commonly referred to as *dismantlement, restoration, and abandonment costs* or *DR&A costs*.

Equipment salvage values may offset the plugging and abandonment costs of onshore wells so that net DR&A costs are zero. However, for some offshore wells, estimated future net DR&A costs may exceed $1 million per well due to the cost of removing offshore platforms, equipment, and perhaps pipelines.

When a leased property is no longer productive, the lease expires and the oil company plugs the wells and abandons the property. All rights to exploit the minerals revert back to the lessor as the mineral rights owner.

ACCOUNTING DILEMMAS

The nature of petroleum exploration and production raises numerous accounting problems. Here are a few:

- Should the cost of preliminary exploration be recorded as an asset or an expense when no right or lease might be obtained?
- Given the low success rates for exploratory wells should the well costs be treated as assets or as expenses? Should the cost of a dry hole be capitalized as a cost of finding oil and gas reserves? Suppose a company drills five exploratory wells costing $1 million each, but only one well finds a reservoir and that reservoir is worth $20 million to the company. Should the company recognize an asset for the total $5 million of cost, the $1 million cost of the successful well, the $20 million value of the productive property, or some other amount?

- The sales prices of oil and gas can fluctuate widely over time. Hence, the value of rights to produce oil and gas may fluctuate widely. Should such value fluctuations affect the amount of the related assets presented in financial statements?
- If production declines over time and productive life varies by property, how should capitalized costs be amortized and depreciated?
- Should DR&A costs be recognized when incurred, or should an estimate of future DR&A costs be amortized over the well's estimated productive life?
- If the oil company forms a joint venture and sells portions of the lease to its venture partners, should gain or loss be recognized on the sale?

As will be explained in this book, the nature, complexity, and importance of the petroleum E&P industry have caused the creation of an unusual and complex set of rules and practices for petroleum accounting and financial presentation.

HISTORY OF THE PETROLEUM INDUSTRY IN THE UNITED STATES

In order to understand the importance and nature of financial accounting and reporting in the petroleum industry, it is helpful to briefly review the industry's history, particularly in the United States over the past twenty years.[5] Several exhibits will be presented to show how the industry's economic characteristics have changed over the years and to portray the industry's current economic status.

In ancient history, pitch (a heavy, viscous petroleum) was used for ancient Egyptian chariot axle grease. Early Chinese history reports the first use of natural gas that seeped from the ground; a simple pipeline made of hollowed bamboo poles transported the gas a short distance where it fueled a fire used to boil water.

Seventeenth century missionaries to America reported a black flammable fluid floating in creeks. From these creeks, Indians and colonists skimmed the crude oil, then called rock oil, for medicinal and other purposes. Later, the term *rock oil* would be replaced by the term *petroleum* from *petra* (a Latin word for rock) and *oleum* (a Latin word for

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[5]More extensive discussions of global and U.S. petroleum history are found in Daniel Yergin, *The Prize* (New York: Simon & Schuster, 1991), Harold F. Williams and Arnold R. Arum, *The American Petroleum Industry* (Evanston: Northwestern University Press, 1959), and Stanley Clark, *The Oil Century* (Norman: The University of Oklahoma Press, 1958).

oil). Eventually, the term petroleum came to refer to both crude oil and natural gas.

By the early 1800s, whale oil was widely used as lamp fuel, but the dwindling supply was uncertain, and people began using alternative illuminating oils called kerosene or coal oil extracted from mined coal, mined asphalt, and crude oil obtained from surface oil seepages. At the same time, U.S. settlers were drilling wells to produce salt brine for salt production and occasionally encountered crude oil mixed with the produced brine. In 1856, George Bissell, an investor in the Pennsylvania Rock Oil Company, surmised that similar wells could be drilled to find and economically produce crude oil from which valuable kerosene could be extracted.

The petroleum exploration and production industry may be said to have begun in 1859. While there is mention of an oil discovery in Ontario, Canada, in 1858, it is generally recognized that Bissell's company had the first commercial oil drilling venture in 1859 near Titusville, Pennsylvania.

Colonel Edwin L. Drake, a retired railroad conductor, supervised the drilling activity on behalf of the Pennsylvania Rock Oil Company. A steam-powered, cable-tool rig with a wooden derrick was used to drill the 69-foot well, which produced approximately five barrels of crude oil per day.

Soon after the Drake well began oil production, other wells were drilled in the Titusville area using cable-tool rigs, and the supply of oil increased dramatically, causing a decline in the price of crude oil from $10 per barrel in January 1860 to about ten cents a barrel two years later. Shortly thereafter, a number of refineries began distilling valuable kerosene from crude oil, including facilities that had previously extracted kerosene from other sources.

THE INDUSTRIAL REVOLUTION AND THE GROWTH OF "BIG OIL"

At the start of the U.S. Civil War, approximately 200 wells were producing over one-half million barrels annually. The introduction of petroleum-based lamp fuel was only the beginning of an increasing variety of uses for crude oil and its refined products. For example, the Industrial Revolution and the Civil War created a demand for lubricants as a replacement for turpentine. By the year 1870, annual total production of petroleum exceeded 25 million barrels.

Transportation of crude oil was a problem faced from the earliest days of oil production. The coopers' union constructed wooden barrels (with a capacity of 42 to 50 gallons) that were filled with oil and hauled by teamsters on horse-drawn wagons to railroad spurs or river barge docks. At the railroad spurs, the oil was emptied into large wooden tanks that were placed on flatbed railroad cars. The quantity of oil that could be moved by this method was limited. However, the industry's attempts to construct pipelines were delayed by the unions whose members would face unemployment and by railroad and shipping companies who would suffer from the loss of business by the change in method of transportation. Nevertheless, pipelines did come into existence in the 1860s; the first line was made of wood and was less than a thousand feet long.

Growth in the physical production of petroleum corresponded with growth in the size and investment of corporations engaged in producing and refining petroleum. One of the companies involved in the petroleum industry was partially owned by John D. Rockefeller; in 1865 he acquired the entire interest in the company. In 1870 Rockefeller merged his firm with four other companies to form the Standard Oil Company. His original goal was to become paramount in the refining, transporting, and marketing of petroleum; but shortly after the merger, he also moved into the area of oil production.[6]

Rockefeller's plan for dominance succeeded, and during the 1880s Standard controlled approximately 90 percent of the refining industry in the country and dominated the global petroleum industry. Standard's control of refineries as well as its ownership of railroads, pipelines, and marketing outlets forced most petroleum customers in the United States to purchase their products from the company.[7]

Standard's dominance did not escape federal and state antitrust regulators. After the discovery of the prolific Spindletop field near Beaumont, Texas, in 1901, the Texas legislature passed laws preventing Standard's involvement in Spindletop. As a result, other companies were formed, and some evolved into vertically integrated companies, such as Texaco, organized in 1901. In addition to state antitrust laws, federal legislation had a great impact on Standard Oil Company and led to its break-up in 1911-1915 into several companies that today have a combined market value exceeding $200 billion. They include:

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[6]Albert Z. Carr. *Rockefeller's Secret Weapon* (New York: McGraw-Hill Book Co., Inc., 1962).

[7]J.G. McLean and R.W. Haigh, *The Growth of Integrated Oil Companies* (Boston: Harvard University Graduate School of Business Administration, 1954).

- Standard Oil of New Jersey (i.e., Exxon) and Standard Oil of New York (i.e., Mobil) that merged in 1999 to form ExxonMobil, the largest U.S. petroleum company and a world giant;
- Standard Oil of California (now Chevron, the second largest U.S. petroleum company);
- Standard Oil of Indiana (subsequently renamed Amoco) and Standard Oil of Ohio, both now a part of BP Amoco, following merger with or acquisition by British Petroleum to create a world giant rivaling ExxonMobil;
- Continental Oil (now Conoco, eighth largest U.S. oil company).[8]

After the breakup of the Standard Oil Company, Europe's Royal Dutch/Shell Group succeeded Standard Oil as the world's largest oil company. The group was an unusual amalgamation that was owned 60 percent by the Netherlands's Royal Dutch Company and 40 percent by England's Shell Transport and Trading Company. Royal Dutch had made its fortunes in oil production in the Dutch East Indies, now Indonesia. Shell had prospered in global oil trading and transportation before expanding into production and refining.

THE 1920s: THE AUTOMOBILE COMES OF AGE

With increased competition in the oil industry and an increased demand for petroleum products (created by the growing number of automobiles), many small companies were formed and soon joined the few large companies in the search for and production of petroleum. New demands for petroleum were created in the 1920s; petroleum products were used to generate electricity, operate tractors, and power automobiles. The oil industry was able to increase production to meet the greater demand without a sharp rise in price.

The search by American companies for foreign oil began around 1920 and was encouraged by the United States government, which feared that a shortage of oil was developing domestically. By the middle of the 1920's approximately 35 companies had invested upwards of $1 billion exploring for and developing reserves in the Middle East, South America, Africa, and the Far East. However, the discovery of the giant East Texas oil field in 1930 created a world surplus of oil, and companies slowed their operations in foreign countries. Some companies did continue to search

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[8]Rankings are per the *Oil & Gas Journal*, September 1999, on the basis of total assets.

for oil in the Middle East during the 1930s, and significant discoveries were made, especially in Saudi Arabia and Kuwait.

THE DEPRESSION: STATE CONTROL OVER PRODUCTION

When the depression began in the 1930s, the oil industry entered a period of increased production with the discovery of the East Texas oil field by an independent wildcatter. This field is the third largest in North America; only the Prudhoe Bay field on the North Slope of Alaska and a Mexican field are larger. The abundance of oil from the East Texas field and the economic depression coupled to temporarily reduce oil prices by 90 percent to just ten cents a barrel.

In 1933 the Texas legislature recognized the need for conservation measures to avoid wasting oil and, thus, gave the job of industry regulation to the existing Texas Railroad Commission. Since that time other oil-producing states have created agencies or commissions to regulate the development and production of oil and gas reserves.

The 1930s also saw an increase use of gasoline, natural gas, and natural gas liquids. While some shallow "offshore" drilling occurred as early as the late 1800s, it was not until the late 1930s that wells were drilled from structures resembling the offshore drilling platforms of today.

WORLD WAR II: PETROLEUM FOR DEFENSE

The United States started to recover from the economic depression by the mid-1930s. The onset of World War II in 1939 accelerated the pace of economic recovery. Compared with World War I, World War II used more mechanized equipment, airplanes, automotive equipment, and ships, all of which required huge amounts of petroleum. The industry easily met the United States' and allies' demands for petroleum. However, as World War II progressed, the U.S. and British governments feared an eventual shortage of crude oil. In 1943 the U.S. government even proposed buying from Chevron and Texaco the petroleum company that became Saudi Aramco, now the world's largest oil producing company.

During and after World War II, huge capital investments were made to further develop the enormous reserves found in the Persian Gulf area. Chevron, joined later by Texaco, and still later by Exxon and Mobil, owned the Arabian-American Oil Company or Aramco, which developed the giant Saudi Arabian oil fields and downstream infrastructure. Today the company is owned by Saudi Arabia and has been renamed Saudi Aramco. Other companies explored, developed, and produced oil in other countries, but in the first half of the twentieth century, the United States typically produced and consumed from 50 percent to 75 percent of the world's annual oil production.

AFTER WORLD WAR II: GROWTH OF THE NATURAL GAS AND PETROCHEMICAL INDUSTRIES

At the end of World War II, two events contributed to the tremendous growth in the natural gas industry. Natural gas had previously been discovered in large quantities in Texas, Louisiana, and other southwestern states; however, it was difficult to transport the gas long distances. This problem was alleviated by the development of a new technique for welding large pipe joints; gas under high pressure thus became transportable to the heavily populated midwestern and eastern regions of the country. Also, after World War II, the country witnessed the birth of the petrochemical industry, which used natural gas liquids for some of its basic raw materials.

THE 1950s AND 1960s: IMPORTED OIL AND THE FORMING OF OPEC

During the 1950s and the 1960s, there was ample world oil production, with prices remaining stable and averaging approximately $3.00 per barrel. However, these two decades also saw an increased U.S. reliance on imported crude oil and refined products. In 1950 ten percent of oil used in the United States was supplied by imported oil and refined products; by 1970 that percentage had increased to 23 percent.

In 1960 the Organization of Petroleum Exporting Countries (OPEC) was formed by Saudi Arabia, Kuwait, Iran, Iraq, and Venezuela. Later, eight other countries joined OPEC—the United Arab Emirates and Qatar in the Middle East; the African countries of Algeria, Gabon, Libya and Nigeria; and the countries of Indonesia and Ecuador. Ecuador withdrew in late 1992. By 1973 OPEC members produced 80 percent of world oil exports, and OPEC had become a world oil cartel. Member countries began to nationalize oil production within their borders.

THE 1970s: OIL AND GAS PRICES SKYROCKET. U.S. IMPOSES PRICE CONTROLS

Beginning in October 1973, Arab OPEC members cut off all oil exports to the U.S. in response to the U.S.'s proposed $2.2 billion military aid package to Israel, which was reeling from surprise attacks by Egypt and Syria that month. The price for Saudi Arabian oil rose dramatically—$1.80 per barrel in 1971, $2.18 in 1972, $2.90 by mid-1973, $5.12 in

October 1973, and $11.65 in December 1973. Thereafter, world crude oil prices increased slowly through 1978 when Saudi oil sold for $12.70 per barrel. The 1979 Iranian Revolution caused prices to again escalate rapidly, peaking at $42 per barrel for some U.S. crude oil in December 1979.

During the 1960s and early 1970s, some people warned of petroleum shortages, but their warnings went unheeded until the 1973 Arab oil embargo. Because of the embargo, a large portion of the oil normally imported by the United States was cut off for several months, and citizens were faced with a shortage of gasoline and other petroleum products and with increasing prices. The federal government created the Federal Energy Administration in 1973 and gave it the power to control prices of crude oil. The price regulations were complex, and compliance procedures were not always clearly determinable, even after petroleum company personnel consulted with officials of the Federal Energy Administration, predecessor to the U.S. Department of Energy (DOE).

A two-tier oil pricing structure was established with a low price for "old" or "lower-tier oil" and a higher price for "new" or "upper-tier oil." Lower-tier oil generally came from properties that were producing prior to 1973, while upper-tier oil came from properties that began producing after 1972. Producers often had both kinds of properties and therefore sold some oil at less than half the price of other oil of the same quality. By 1979 the U.S. allowed free market prices for U.S. oil from newly drilled properties or properties producing less than 10 barrels per day per well. However, on average, domestic oil was selling at only a fraction of the price paid in this country for imported oil.

Foreign oil continued to be imported (at prices exceeding domestic oil prices) to meet the continued growth in domestic demand. In 1977, approximately 47 percent of the United States' needs were met by imported oil.

THE WINDFALL PROFIT TAX (1980 TO 1988)

President Carter's call for phased decontrol of oil prices by late 1981 was coupled with enactment of the Windfall Profit Tax Act in March 1980. The Act levied a tax from 30 percent to 70 percent on *windfall profit*, i.e., the excess of the selling price of a barrel of oil over the *adjusted base price* for that barrel. The adjusted base price was an inflation-adjusted average price of similar oil sold in late 1979. Congress repealed the windfall profit tax in 1988 after oil prices had fallen so low that no *windfall profit* was left to tax.

ALASKA NORTH SLOPE OIL

In 1968 Prudhoe Bay, the United States' largest oil field, was discovered on the North Slope of Alaska bordering the Arctic Ocean. In 1969, the giant Kuparuk field adjacent to Prudhoe Bay was discovered. Prior to the Prudhoe Bay discovery by Atlantic Richfield Company (ARCO), seven very expensive, but unsuccessful, exploratory wells had been drilled in the area, and ARCO almost canceled drilling the discovery well. Even after discovery, Prudhoe Bay development was stalled until the 1973 Arab oil embargo prompted Congress to allow the Trans Alaska Pipeline System (or TAPS) to be built. Finally, in 1977 Prudhoe Bay and Kuparuk crude oils were produced and marketed.

For Prudhoe Bay and Kuparuk, estimated ultimate oil production, i.e., all prior production plus estimated future production, is 13.2 billion and 2.6 billion barrels, respectively. Gas reserves approximate 4 billion additional equivalent barrels. These North Slope fields are immense. In the entire lower 48 states where over one million wells have been drilled, only three discovered oil fields have ultimate oil production exceeding 2 billion barrels, and their combined ultimate production is only 10.9 billion barrels. Alaska North Slope oil (*ANS crude*) made up approximately 18 percent of all 1998 U.S. oil production.

The North Slope infrastructure for production of Prudhoe Bay and Kuparuk is used to economically produce some 20 smaller North Slope reservoirs. However, the huge 32 trillion cubic feet (tcf) of recoverable natural gas reserves from North Slope fields cannot now be economically transported to the Lower 48 states. Advances in converting gas to liquids (GTL, described on page 5) offer hope. Alternatively, the gas may eventually be chilled as LNG and shipped to Asia’s Pacific Rim.

North Slope operations are an industry model for environmental protection, far different from the typical Russian operation. A Russian environmental scientist touring the Prudhoe Bay production facilities declared that north slope production must be a government hoax because he found no oil leaks or spills. Gas produced at Prudhoe Bay is not vented into the atmosphere or burned as waste, but reinjected back into the reservoir. Gas reinjection improves oil recovery and saves the gas for potential future use. The North Slope’s Alpine field, the largest U.S. onshore oil discovery in fifteen years, spans 40,000 acres; yet its oil (70,000 barrels per day) will be produced from two 50-well gravel pads on less than 120 acres. The Alpine field has no permanent roads or bridges.

In 1998 Alaskan oil production (nearly all from the North Slope) provided 73 percent of the state government’s unrestricted general fund.

The oil royalty has provided a permanent and growing $25 billion trust fund for the half million residents of Alaska.

Despite the industry's success in safeguarding the North Slope environment and adding to the nation's wealth, and contrary to the wishes of most Alaskans and local Inuits, the North Slope's 19 million acre Arctic National Wildlife Refuge (ANWR) remains closed by the federal government to drilling and production. The federal government estimates that the western half of ANWR's 1.7 million acre coastal plain has recoverable oil reserves of several billion barrels.

THE 1980s: BOOM AND BUST. MARKET FORCES PREVAIL

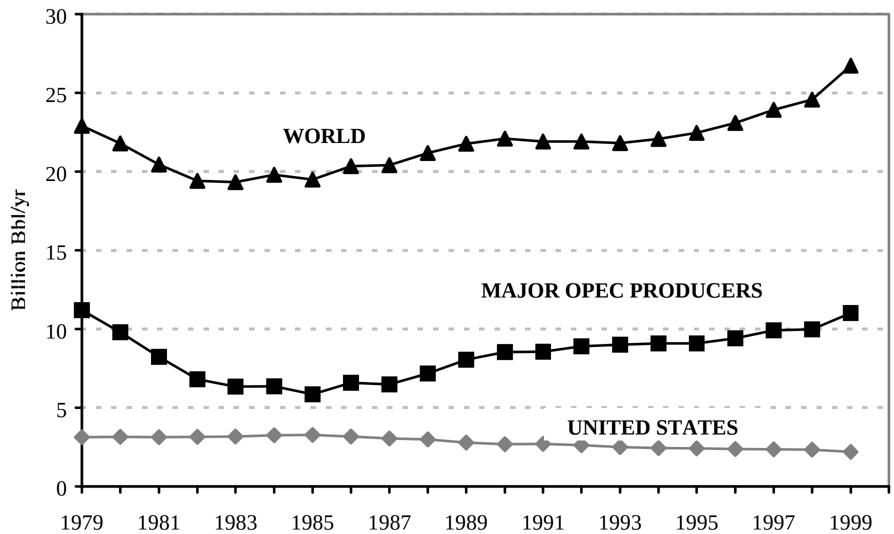
Several factors set the stage for a U.S. petroleum industry boom in 1981 and 1982:

- World oil prices had increased astronomically in 1973 and 1979. These price increases improved exploration economics and created an expectation of substantial price increases in the future.
- In January 1981, President Reagan removed U.S. price controls on crude oil, which gave producers additional cash to reinvest. In the 1970s, Libya and several other countries seized U.S. companies' interests in petroleum fields. These nationalizations encouraged a preference for U.S. companies to explore within the United States.
- The Natural Gas Policy Act of 1978 created incentive pricing schemes to stimulate the exploration and development of natural gas reserves.

In 1981 U.S. tax laws were changed to reduce the highest individual income tax rates from 70 percent to 50 percent and reduce windfall profit taxes on new oil fields. Individuals investing in wells drilled in 1981 could earn a 40 percent profit, after income tax effects, on wells that had no profit before income tax effects. Consequently, in 1981 and 1982, U.S. individuals invested billions of dollars in limited partnerships for petroleum exploration and production.

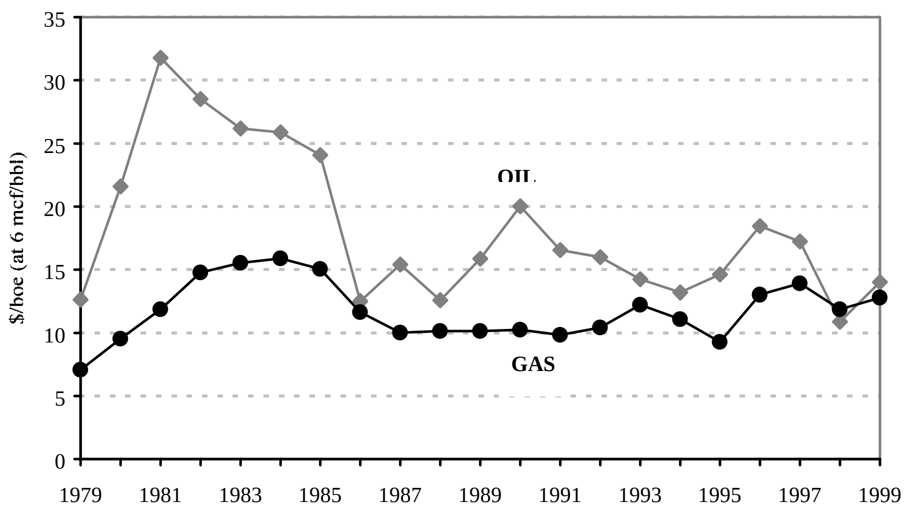
Figures 1-2, 1-3, and 1-4 present a history of annual production, prices, and E&P expenditures from 1979 through 1999 that portray the boom and bust of the 1980s.

Figure 1-2: World Crude Oil Production
1979-1999



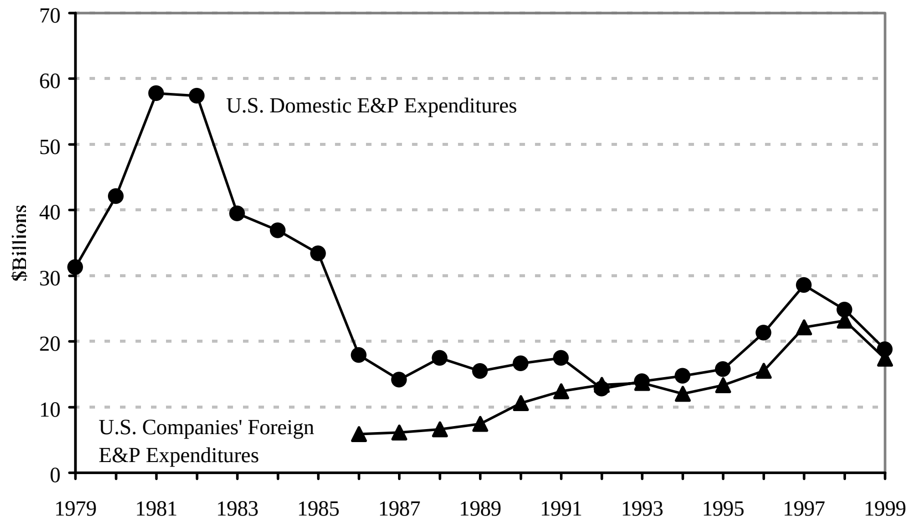
Primary Sources: DeGolyer and MacNaughton, *Twentieth Century Petroleum Statistics*, 1998; *Oil & Gas Journal*, December 31, 1998; and Robert J. Beck, *Worldwide Petro- leum Industry Outlook 2000-2004* (16th Edition).

Figure 1-3: Average Annual U.S. Oil & Gas Prices
1979-1999



Primary Source: Robert J. Beck, *Worldwide Petroleum Industry Outlook 2000-2004* (16th Edition).

Figure 1-4: U.S. Domestic and Foreign E&P Expenditures 1979-1999



Primary Source: Robert J. Beck, *Worldwide Petroleum Industry Outlook 2000-2004* (*16th Edition*).

As shown in Figure 1-2, the major OPEC producers' market share for world oil dropped from 48 percent in 1979 to 30 percent in 1985 because increasing oil prices in the late 1970s and early 1980s (Figure 1-3) reduced world demand and production of oil (Figure 1-2). The early high prices and other factors brought about the U.S. drilling boom—almost $120 billion was spent in the 1981 and 1982 period (Figure 1-4). When the leading oil exporting country Saudi Arabia refused in 1986 to further reduce market share, world oil prices fell by 50 percent (Figure 1-3). With the 1986 oil price collapse, global and U.S. exploration and development activity substantially decreased (Figure 1-4); oil demand increased (Figure 1-2); OPEC's exports nearly doubled (Figure 1-2); and oil prices hovered at $15 to $18 per barrel for the remainder of the 1980s (Figure 1-3).

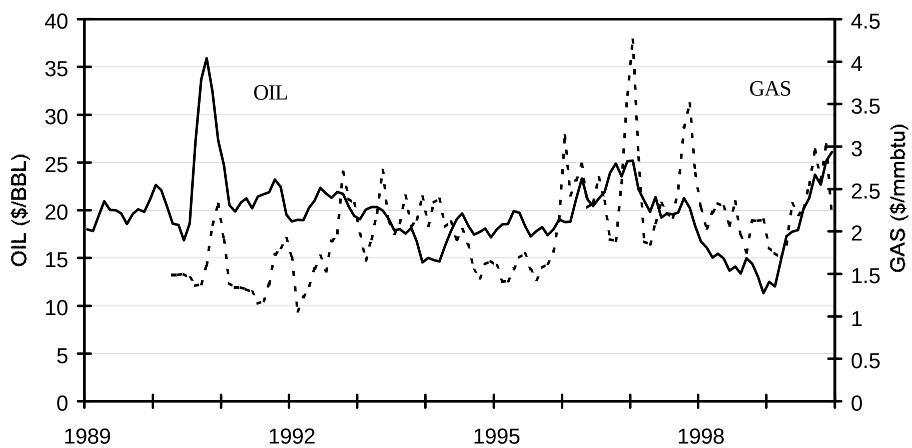
THE 1990s: FUTURES, NATURAL GAS, GOING INTERNATIONAL, AND TECHNOLOGY ADVANCEMENTS

The 1990s have been marked by five trends: (1) growing use of oil and gas futures, (2) growth in natural gas production and value in the U.S., (3) restructuring of the U.S. gas industry, (4) increasing focus by U.S. companies on foreign E&P investments, and (5) continued improvements in technological and operational efficiencies.

The late 1980s and early 1990s saw increased price volatility (Figure 1-5). In the fall of 1990, oil prices briefly spiked upward after Iraq's invasion of Kuwait and quickly fell back as the United States led armed forces in the liberation of Kuwait.

In response to weakening demand in Asia and other factors, oil prices declined briefly in late 1998 to around $11 per barrel with fears of a prolonged price decline. Several major producing countries agreed on production cuts in early 1999. Oil prices more than doubled in 1999 (Figure 1-5). By February 2000, the oil price for WTI at Cushing had reached $30.

Figure 1-5: Monthly NYMEX Crude Oil and Natural Gas Settlement Prices
January 1989 – December 1999



Primary Source: *Oil & Gas Journal Database*

Note: Oil prices are a monthly average for the calendar month indicated for WTI at Cushing, reported each business day by NYMEX for the prompt month. Gas prices are an average of the prices reported by NYMEX for the last three trade days for gas delivered at Henry Hub for the calendar month indicated.

With greater historical and expected price volatility, petroleum producers, processors, and users increased their use of petroleum futures and saw the 1990 birth of natural gas futures. Oil and gas futures are publicly traded standardized contracts to buy or sell specified quantities of crude oil or natural gas at specified times in the future at specified prices. Futures may be used to hedge or speculate on crude oil and natural gas prices, as further explained in Chapter Thirty-Two. Similar contracts have arisen for call (and put) options to buy (and sell) specified quantities at specified prices until specified dates.

Worldwide, natural gas demand is growing faster than crude oil demand. Natural gas is a cleaner fuel, appealing to growing environmental concerns. In 1993, for the first time in history, the value of U.S. natural gas production exceeded the value of U.S. crude oil production. In that sense, the U.S. petroleum industry has become the "gas and oil" industry.

The traditional marketing of natural gas to gas pipelines under long-term contracts has been replaced by selling gas at spot prices to gas marketers and gas consumers (end-users) under month-long contracts. Average U.S. gas prices have become seasonal—high in winter months when cold weather increases gas demand for space heating and relatively low in the warmer summer months (see Figure 1-5). Changes in federal regulation of interstate gas pipelines have enabled pipelines to become providers of gas transportation rather than serve as the traditional first purchasers and resellers of produced natural gas (as further explained in Chapter Twelve).

In the 1990s, U.S. petroleum companies doubled their petroleum exploration and development costs outside the United States (Figure 1-4). Foreign E&P opportunities have emerged following (1) the political restructurings of the Former Soviet Union and (2) the growing sophistication and interest of countries, such as Venezuela, in attracting investments by petroleum companies from around the world. Flat domestic spending has contributed to declining U.S. production and increased reliance on imports. In 1998, imported crude and refined products supplied over half of U.S. demand (Figure 1-7).

In the late 1980s, the United States was viewed as a poor area of the world for new discoveries. It had been heavily drilled by world standards, and its most promising regions for new fields were off limits to protect local environment. In the 1990s, U.S. prospects were favorably reversed by technology advancements that substantially reduced exploration and development risks and costs. Exploration and development activity in the United States more than doubled from 1990 to 1999.

Productive offshore fields are being explored and developed in deeper waters. As explained in Chapter Five, exploration success, both onshore and offshore, has been improved by the use of *3D seismic* to identify likely reservoirs with less use of exploratory wells. Well cost per reserve volume has declined through the use of new techniques to drill *horizontal wells* in which the well bore starts vertically downward and bends to become a horizontal shaft through wide reservoirs of limited thickness. The industry has learned to economically produce substantial natural gas and oil from exotic sources, primarily:

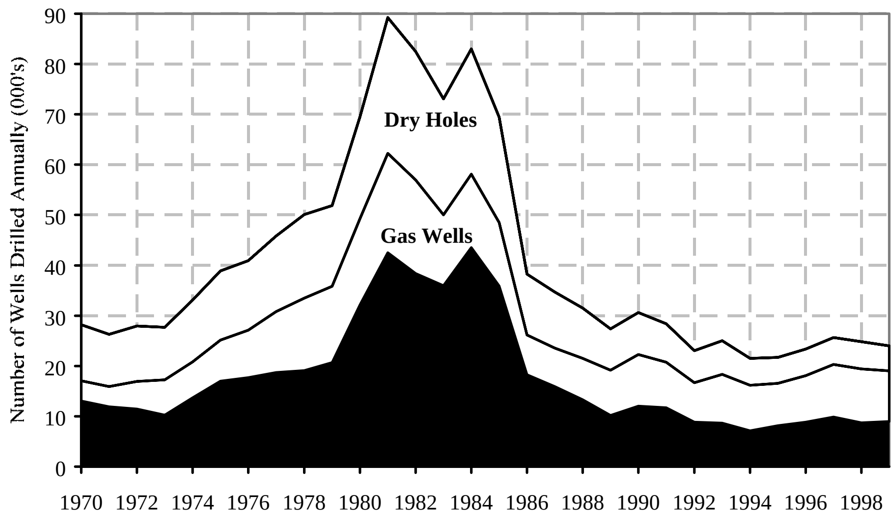
- methane contained in underground coalbeds,
- natural gas from continuous tight sands formations that are opened up by fracturing the rock with fracing material temporarily pumped under high pressure into the reservoir, and
- oil recovered from mined oil sands, such as the vast oil sands of Alberta that are being developed to provide some 25 percent of Canada’s light oil production.

Coalbed methane production in the U.S. increased ten-fold in the 1990s and now exceeds 1 trillion cubic feet per year, from over 7,500 wells. Coalbed methane reservoirs are estimated to contain 146 tcf, or 14 percent, of the United States total recoverable natural gas resources.

STATISTICAL HISTORY OF THE PETROLEUM INDUSTRY

To supplement the preceding history of the petroleum industry, Figures 1-6 through 1-9 provide graphical histories from 1970 to the late 1990s and tabular histories for the past ten years of U.S. drilling, production, imports, and reserves. Figure 1-10 illustrates changes since 1920 in the mix of products refined from crude oil.

Figure 1-6: U.S. Wells Drilled

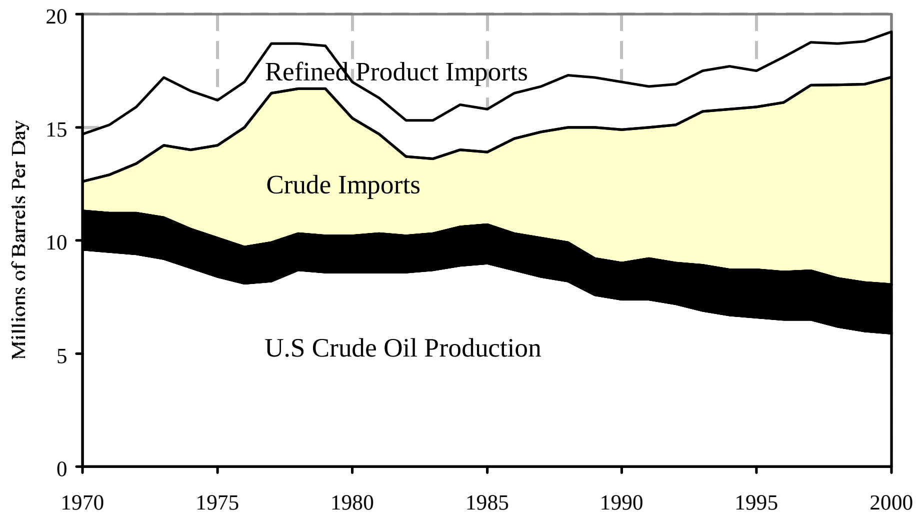


Number of U.S. Wells Drilled Annually (000's) since 1990

	Dry	Gas	Oil	Total	Exploratory
1990	8.4	10.2	12.0	30.6	5.1
1991	7.7	9.0	11.7	28.4	4.4
1992	6.4	7.9	8.8	23.1	3.5
1993	6.6	9.7	8.7	25.0	3.5
1994	5.3	9.1	7.1	21.5	3.5
1995	5.2	8.4	8.1	21.7	3.3
1996	5.3	9.2	8.8	23.3	3.2
1997	5.3	10.4	9.9	25.6	3.0
1998	5.5	10.7	8.7	24.9	2.6

Primary sources: DeGolyer & MacNaughton, *Twentieth Century Petroleum Statistics*, 1998 and Independent Petroleum Association of America (www.ipaa.org/departments/information_services).

Figure 1-7: U.S. Annual Liquid Hydrocarbon Production and Imports

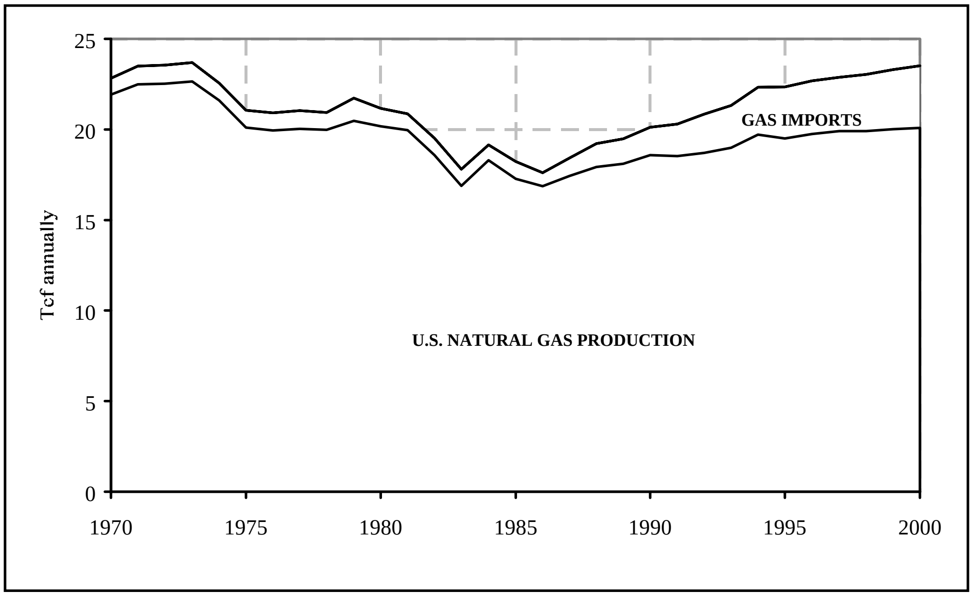


U.S. Liquid Hydrocarbons Production and Imports since 1990
(millions of barrels per day)

	U.S. Production			Imports		Total
	Crude*	NGL**	Total	Crude	Refined Product	
1990	7.4	1.6	9.0	5.9	2.1	17.0
1991	7.4	1.8	9.2	5.8	1.8	16.8
1992	7.2	1.8	9.0	6.1	1.8	16.9
1993	6.9	2.0	8.9	6.8	1.8	17.5
1994	6.7	2.0	8.7	7.1	1.9	17.7
1995	6.6	2.1	8.7	7.2	1.6	17.5
1996	6.5	2.1	8.6	7.5	2.0	18.1
1997	6.5	2.2	8.7	8.2	1.9	18.8
1998	6.2	2.1	8.3	8.6	1.8	18.7
1999	6.0	2.1	8.1	8.8	1.9	18.8
2000	5.9	2.2	8.1	9.2	2.0	19.3

*Crude includes condensate.
**NGL includes non-NGL liquid hydrocarbons of less than 0.4 million barrels per day in years prior to 1999.
Note: 1999 and 2000 data are projected estimates.
Primary Sources: DeGolyer and MacNaughton, *Twentieth Century Petroleum Statistics*, 1998, and Robert J. Beck, *Worldwide Petroleum Industry Outlook 2000-2004* (16th Edition).

Figure 1-8: U.S. Annual Natural Gas Production and Imports



U.S. Gas Production and Imports since 1990

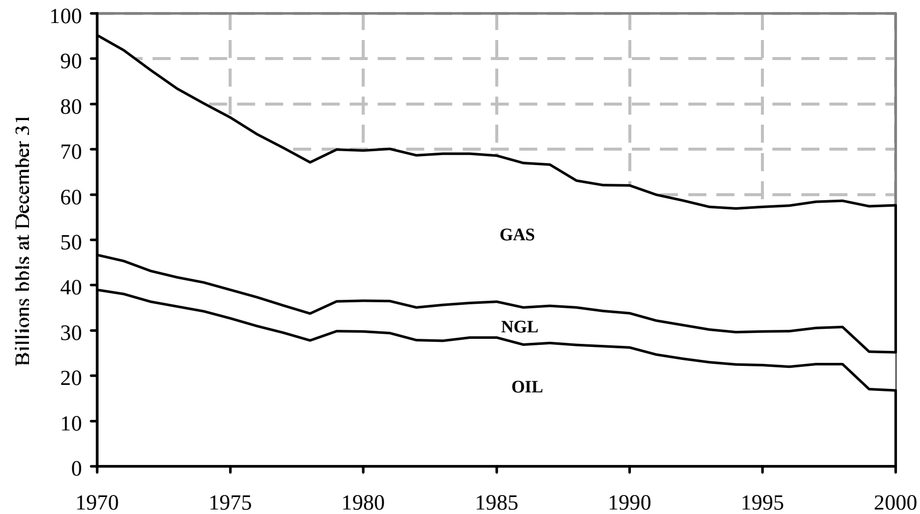
	Gas Production (tcf)	Gas Imports* (tcf)	Total (tcf)
1990	18.6	1.5	20.1
1991	18.5	1.8	20.3
1992	18.7	2.1	20.8
1993	19.0	2.4	21.4
1994	19.7	2.6	22.3
1995	19.5	2.8	22.3
1996	19.8	2.9	22.7
1997	19.9	3.0	22.9
1998	19.9	3.1	23.0
1999**	20.0	3.3	23.3
2000**	20.1	3.5	23.6

*Primarily from Canada

** 1999 to 2000 data are projected estimates

Primary Sources: DeGolyer & MacNaughton, *Twentieth Century Petroleum Statistics*, 1998, and Robert J. Beck, *Worldwide Petroleum Industry Outlook 2000-2004* (16th edition).

Figure 1-9: U.S. Oil and Gas Proved Reserves



Estimated U.S. Proved Oil and Gas Reserves at December 31

	Billions of Barrels of Oil Equivalent				Gas
	Crude	NGL	Gas*	Total	(tcf)
1990	26.3	7.6	28.2	62.1	169
1991	24.7	7.5	27.8	60.0	167
1992	23.7	7.5	27.5	58.7	165
1993	23.0	7.2	27.0	57.2	162
1994	22.5	7.2	27.3	57.0	164
1995	22.4	7.4	27.5	57.3	165
1996	22.0	7.8	27.7	57.5	166
1997	22.5	8.0	27.9	58.4	167
1998	22.5	8.2	28.0	58.7	167
1999	17.0	8.3	32.1	57.4	193
2000	16.8	8.4	32.5	57.7	195

*Gas tcf converted to billion barrels at 6 tcf/per billion barrels.
** Data for 1999 and 2000 are projected estimates.
Primary Sources: DeGolyer & MacNaughton, *Twentieth Century Petroleum Statistics*, 1998.

Figure 1-10: U.S. Refined Products for Five Representative Years

	Millions of Barrels Produced Annually					
	1920	1940	1960	1980	1998	1998%
Gasoline	116	597	1,523	2,394	2,888	52.3%
Kerosene	55	74	104	50	28	0.5%
Jet Fuel	-	-	88	366	557	10.1%
Fuel Oils:						
Distillate	211	183	667	975	1,250	22.7%
Residual	-	316	332	577	278	5.0%
Lubricants	25	37	59	65	67	1.2%
Wax	2	2	6	6	8	0.1%
Coke	3	8	60	135	260	4.7%
Asphalt	7	29	99	141	182	3.3%
Total	419	1,246	2,938	4,709	5,518	100.0%

Figure 1-10 primary sources: DeGolyer & MacNaughton, *Twentieth Century Statistics*, 1998 and U.S. Energy Information Administration's *Petroleum Supply Annual*, 1998

Note: Although gasoline production has substantially increased since 1960, annual air pollution from automobiles is much less. According to the American Petroleum Institute and the American Automobile Manufacturers Association, new automotive technologies and cleaner gasolines reduced 1994 tailpipe emissions in grams per mile to four percent of the level in 1960 and are expected to drop by the year 2004 to approximately two percent of the 1960 level. According to the U.S. Environmental Protection Agency, overall air pollution from all sources had substantially declined by 1992 from the 1983 levels: airborne lead decreased 89 percent; carbon monoxide, 34 percent; sulphur dioxide, 23 percent; and ozone, 21 percent.

Chapter Two

PETROLEUM ECONOMICS

Chapter One includes several charts containing historical economic statistics. Chapter Two emphasizes the importance of E&P reserve values and describes current economics in terms of the leading countries and companies.

A FOCUS ON ADDING RESERVE VALUE

Petroleum exploration and production economics center on the size and nature of oil and gas reserves in relation to oil and gas prices. An E&P company may be said to have two key assets:

1. Its people and their ability to profitably find (or acquire), develop, and produce oil and gas reserves and
2. Its existing reserves and their ability, when produced, to generate positive cash flow.

The ability to apply new technology (such as 3D seismic, horizontal drilling, deep water drilling and production techniques, and global internet knowledge sharing) will be key to managing risks and adding billions in reserve value for the E&P industry in the coming decade.

E&P company managements appreciate that true exploration success is not measured by the *success ratio*, i.e., the number of producible wells to total wells drilled. A ten-well program with discovery of a single large reservoir may be far more profitable than a ten-well program discovering five marginally economic reservoirs. Nor is exploration success truly measured by the quantity of reserves found. In many remote parts of the world, large quantities of gas reserves have been found that have relatively limited value because transportation costs to gas markets are so high.

A U.S. property with one million barrels of proved heavy, sour crude oil reserves with high future development and production costs might sell for only $1 million, while a fully developed U.S. property with one million barrels of proved light, sweet crude oil and low production costs might sell for $6 million. Hence, an E&P company often must evaluate potential E&P investments using sophisticated computer-generated, present value analyses of expected future cash flows.

These analyses can project estimated future monthly production volumes, revenues, and production expenses per well over the well's economic life of many years. From these projected cash flows and the required investment, an expected annual rate of return and other profit indicators can be calculated to evaluate the investment's economic merits. Often a company's records of historical production, revenue, and cost categories by well and by field are instrumental in developing reasonable cash flow projections for investment decision making. Such analysis is illustrated in Chapter Thirty on valuation of proved oil and gas properties. Historical cost may be dramatically greater or less than the value of reserves found. E&P financial statement accounting recognizes the economic importance of reserves in three ways:

- Capitalized costs of properties with proved reserves (proved properties) are amortized on a units-of-production method based on the ratio of volumes currently produced to the sum of those volumes and remaining proved reserves;
- Proved properties' net capitalized costs are limited to certain computations of value of the underlying proved reserves; and
- Public companies must disclose, with audited financial statements, certain supplemental unaudited information on the proved reserve volumes and certain related values.

Even so, an E&P company's stock price is more closely correlated to historical and expected cash flow from production of reserves and to estimated values of reserves than to historical earnings measured under generally accepted accounting principles, as further discussed at the end of Chapter Twenty-Nine.

PETROLEUM ECONOMICS TODAY FROM A GLOBAL PERSPECTIVE

The world's reserve values by country are not publicly disclosed, but estimated reserve volumes are. Figure 2-1 summarizes the world's proved oil and gas reserves, production, and oil wells by country. Over 92 percent of the world's proved oil and gas reserves are found in the 25 countries listed in Figure 2-1. The top ten countries have nearly 80 percent of the world's oil and gas reserves and the majority of the world's current production. Sixty-four percent of the world's proved oil reserves are in five Middle East countries, and the majority of the world's proved oil and gas reserves are in only four countries—Russia, Saudi Arabia, Iran and Iraq.

Figure 2-1: World Reserves and Production by Country

Twenty-five largest (OPEC members in bold)	Reserves (1/1/00)			Annual Production			
	Oil*	Gas*	Total Boe*	Oil*	Gas*	Total Boe*	Oil Wells*
1 Russia	49	1,700	382	2.2	20.5	5.6	104.1
2 **Saudi Arabia**	261	204	295	2.7	1.6	3.0	1.4
3 **Iran**	90	812	225	1.3	1.8	1.6	1.1
4 **Iraq**	113	110	131	1.0	-	1.0	1.7
5 **Abu Dhabi (UAE)**	92	196	125	0.6	-	0.6	1.2
6 **Kuwait**	94	52	103	0.6	0.3	0.7	0.8
7 **Venezuela**	73	143	97	1.0	1.1	1.2	14.7
8 **Qatar**	4	300	54	0.2	0.7	0.3	0.3
9 United States	21	164	48	2.2	18.9	5.3	574.0
10 **Nigeria**	23	124	44	0.7	0.2	0.7	2.0
11 **Libya**	30	46	38	0.5	0.2	0.5	1.9
12 Mexico	28	30	33	1.1	1.2	1.3	3.6
13 China	24	48	32	1.2	0.8	1.3	72.3
14 **Algeria**	9	130	31	0.3	2.6	0.7	1.3
15 Turkmenistan	1	101	18	0.0	0.4	0.1	2.5
16 Malaysia	4	82	18	0.3	1.5	0.5	0.8
17 Norway	11	41	18	1.1	1.7	1.4	0.6
18 **Indonesia**	5	72	17	0.5	2.4	0.9	8.5
19 Kazakhstan	5	65	16	0.2	0.3	0.2	11.7
20 Canada	5	64	16	0.7	5.7	1.7	50.7
21 Uzbekistan	1	66	12	0.1	1.9	0.4	2.2
22 Netherlands	0	63	11	0.0	2.6	0.5	0.2
23 Australia	3	45	11	0.2	1.1	0.4	1.3
24 Oman	5	28	10	0.3	0.2	0.4	2.3
25 United Kingdom	5	27	10	1.0	3.2	1.5	1.3
Subtotal	956	4,713	1,742	19.8	70.7	31.6	862.5
Others	60	433	132	4.4	10.8	6.2	65.6
Total	1,016	5,146	1,874	24.2	81.5	37.8	928.1

*Oil reserves and production are in billions of barrels. Gas reserves and production are in trillion cubic feet. Combined total reserves and production are in billion barrels of oil equivalent at 6 mcf per barrel. Annual oil production is for 1999; annual gas production is for 1998. Numbers of producing oil wells are in thousands as of December 31, 1998.

Primary Sources: *Oil and Gas Journal*, December 20, 1999 and *BP Amoco Statistical Review of World Energy 1999*

The one trillion barrels of world oil reserves are 50 times current production (Figure 2-1). In 1950 that ratio was only 20. World oil reserves have increased nearly 80 percent since 1981, but virtually all of the increase is in OPEC countries.

Figure 2-2: Ratio of World Reserves to Production by Country and Production Barrels of Oil per Day (BOPD) per Well

Twenty-five largest per Figure 2-1: (OPEC members in bold)	Reserves to Production BOE*	1999 BOPD per Well*
1 Russia	59.7	57
2 **Saudi Arabia**	98.7	5,321
3 **Iran**	144.7	3,147
4 **Iraq**	135.6	1,561
5 **Abu Dhabi (UAE)**	202.2	1,407
6 **Kuwait**	157.7	2,041
7 **Venezuela**	81.3	189
8 **Qatar**	155.0	2,107
9 United States	9.1	10
10 **Nigeria**	58.3	984
11 **Libya**	71.9	703
12 Mexico	26.0	814
13 China	24.7	44
14 **Algeria**	43.3	589
15 Turkmenistan	155.1	51
16 Malaysia	34.7	909
17 Norway	13.1	4,947
18 **Indonesia**	19.5	151
19 Kazakhstan	66.6	45
20 Canada	9.7	37
21 Uzbekistan	31.7	76
22 Netherlands	23.4	290
23 Australia	29.8	365
24 Oman	27.0	389
25 United Kingdom	6.2	2,104
For the top 25 Countries	55.2	63
Other countries	21.2	158
Worldwide	49.6	70
Worldwide, excluding U.S.	56.2	165

*Per data in Figure 2-1
Primary Sources: *Oil & Gas Journal*, December 20, 1999 and
BP Amoco Statistical Review of World Energy 1999

Figure 2-3 lists the World's Top 45 petroleum companies as ranked by the Energy Intelligence Group (EIG) in December 1999. Not surprisingly, the number one company was Saudi Arabia's Saudi Arabian Oil Company or Saudi Aramco (pronounced a-RAM-co) with 26 percent of the world's proved oil reserves.

Figure 2-3: World's Top 45 Petroleum Companies

Country	Rank	State Owned	Company Name (Short Name)
Saudi Arabia	1	100%	Saudi Aramco (Aramco)
Venezuela	2	100%	Petroleos de Venezuela S.A. (PDVSA)
United States	3	-	ExxonMobil
Iran	4	100%	National Iranian Oil Company (NIOC)
UK/Netherlands	4	-	Royal Dutch/Shell Group
UK	6	-	BP Amoco
Mexico	7	100%	Petroleos Mexicanos (Pemex)
France	8	-	TotalFina Elf
Kuwait	9	100%	Kuwait Petroleum Corporation (KPC)
China	10	100%	China National Petroleum Corp. (CNPC)
Indonesia	11	100%	Pertamina
Algeria	12	100%	Sonatrach
United States	13	-	Chevron
Brazil	14	51%	Petrobras
United States	15	-	Texaco
UAE	16	100%	Adnoc
Italy	17	37%	Ente Nazionale Idrocarburi (ENI) - parent of AGIP
Spain	17	21%	Repsol-YPF
Iraq	19	100%	Iraq National Oil Company (INOC)
Libya	20	100%	Libya NOC
China	21	100%	Sinopec
Malaysia	22	100%	Petronas
Russia	23	-	Surgutneftegaz
United States	24	-	Conoco
Nigeria	25	100%	Nigerian National Petroleum Corp (NNPC)
Qatar	26	100%	Qatar General Petroleum Corp (QGPC)
Egypt	27	100%	Egyptian General Petroleum Corp. (EGPC)
United States	28	-	Marathon - (sub of USX)
Russia	29	41%	Gazprom
Russia	30	-	Yukos
United States	31	-	Phillips
Norway	32	100%	Statoil
Russia	33	-	Sidanco
Russia	34	27%	Lukoil
India	35	100%	Oil and Natural Gas Corporation (ONGC)
Colombia	36	100%	Ecopetrol
Russia	37	-	Tyumen Oil
Russia	38	100%	Rosneft
Russia	39	51%	Sibneft
United States	40	-	Amerada Hess
Syria	41	100%	Syrian Petroleum
Oman	42	60%	Petroleum Development Oman (PDO)
Russia	43	77%	Slavneft
Canada	44	18%	Petro-Canada
United States	45	-	Unocal

Primary Source: EIG's *Petroleum Intelligence Weekly*, December 20, 1999 in which EIG updated its Top 50 list to reflect major mergers in 1999 that reduced the number of companies from 50 to 45.

The EIG ranking system for Figure 2-3 reflects an average of rankings for reserves, production, refinery capacity, and product sales.

Some of the national oil companies of the largest oil-producing countries have invested overseas, particularly in refining joint ventures that provide ready customers for exported crude oil. Aramco has a joint venture with Texaco and Shell called Equilon, a major U.S. refiner. Aramco supplies Saudi crude to the Equilon refineries once wholly owned by Texaco and Shell. Venezuela's national oil company, PDVSA (pe-da-VAY-sa), owns CITGO, which has one of the most widely branded gasolines in the United States and is one of the 20 largest U.S. refiners. PDVSA has a refining joint venture in Germany with VEBA (VAY-ba) Oel. Mexico's national oil company, Pemex (pronounced PE-mex, usually with a short e on the first syllable), bought 50 percent of Shell's large U.S. refinery at Deer Park, Texas in 1994 and is supplying Mexican crude to the refinery. Kuwait's national oil company, Kuwait Petroleum Corporation (KPC), owns the Q8 company, a European refining and marketing giant. KPC also owns various other petroleum-related companies in the United States and elsewhere.

By 1994, seven OPEC members owned portions of 35 overseas refineries and had total worldwide refining capacity of ten million barrels per day—equivalent to 40 percent of all OPEC production. The overseas downstream investments discourage a repeat of the 1973 oil embargo.

THE FRAMEWORK FOR U.S. ECONOMICS

The United States, a large producer and consumer of oil and gas, ranks only ninth in combined oil and gas reserves, yet ranks second in annual combined production, and has 62 percent of the world's producing oil wells (Figure 2-1). On average, U.S. oil wells produce 10 barrels per day, whereas Saudi wells produce on average 5,321 barrels per day (Figure 2-2). The U.S. is believed to have substantial undiscovered oil and gas reserves, but:

- Some of those potential reserves are in areas closed to exploration and production under various environmental protection laws;
- Some potential reserves are not believed to be economical to explore unless oil and gas prices rise substantially or exploration, development, and production costs decline substantially; and
- Some reserves are not as economically attractive to find and produce as reserves in other parts of the world.

As shown in Chapter One, U.S. oil and gas companies, as a whole, are actively searching for new oil and gas reserves in many areas of the U.S. and the world.

Unlike many countries, the United States allows mineral rights to be owned by individuals, corporations, and other entities and allows almost any U.S. company to explore and produce oil and gas reserves subject to various federal and state regulations and taxations. Consequently, in the U.S. there are over two million royalty interest owners and over 5,000 E&P companies, partnerships, and sole proprietorships, including some 200 publicly held entities. The U.S. E&P market is highly competitive.

The past successes of the U.S. petroleum industry, the freedom for large numbers of independent entities to own and develop reserves, the country's large land mass, and the citizens' high demand for oil and gas have established an enviable economic framework that explains why the United States has 62 percent of the world's producing oil wells and remains the second largest oil and gas producing country, despite having less than three percent of the world's proved oil and gas reserves. Adverse U.S. tax law changes since 1976, the oil and gas price declines since 1985, and environmental restrictions on U.S. exploration reduced the economic incentives for U.S. exploration in the 1990s.

U.S. oil and gas producers range from giant ExxonMobil with annual sales exceeding $180 billion to individuals holding small interests in one or two wells.

The importance of the petroleum industry in the U.S. and world economy is marked by the fact that the world's four largest corporations in terms of annual revenues are General Motors, DaimlerChrysler, Ford Motor, and now ExxonMobil—three major manufacturers of gasoline powered vehicles and the largest petroleum company. The products of the oil and gas industry are essential to the continued well being and security of this country for the foreseeable future.

Figure 2-4 lists the 40 largest of the 200 largest publicly traded oil and gas producing companies with U.S. petroleum reserves, referred to as the OGJ200, the latest annual list published by the *Oil & Gas Journal* each September. The list does not reflect the merger of Exxon and Mobil.

According to the Independent Petroleum Association of America (IPAA) the petroleum industry employed 1.4 million persons in 1997, of which 320,100 people were in E&P, as shown in Figure 2-5.

Figure 2-4: OGJ200 Oil and Gas Companies, Ranked by Assets

Rank	Company Name	YE 1998 Assets ($000,000)	1998 Revenues ($000,000)	1998 U.S. Production (mboe)*	1998 Global Production (mboe)*
1	Exxon	$92,630	$117,772	333	1,008
2	Mobil ***	42,754	53,531	158	621
3	Chevron	36,540	30,557	232	561
4	Texaco	28,570	31,707	270	508
5	BP Amoco (U.S.)**	27,537	33,160	443	0
6	Shell Oil	26,543	15,451	310	359
7	ARCO ***	25,199	10,809	269	377
8	Conoco	16,075	23,168	87	219
9	Occidental Petroleum	15,252	7,381	69	163
10	USX-Marathon Group	14,544	22,075	98	149
11	Phillips Petroleum Co.	14,216	11,845	94	192
12	Coastal ***	12,304	7,368	46	46
13	Unocal	7,952	5,479	91	190
14	Amerada Hess	7,883	6,617	36	113
15	Union Pacific Resources Group ***	7,642	1,841	107	156
16	Burlington Resources	5,917	1,637	127	138
17	Kerr-McGee	5,451	2,200	59	101
18	Apache	3,996	876	17	33
19	Anadarko Petroleum	3,633	560	48	49
20	Pioneer Natural Resources	3,481	721	50	65
21	Enron Oil & Gas	3,018	769	48	72
22	PennzEnergy ***	2,417	837	49	50
23	Murphy Oil	2,164	1,699	14	37
24	Questar	2,161	906	18	19
25	Ocean Energy	2,007	523	33	45
26	Equitable Resources	1,854	883	12	12
27	Noble Affiliates	1,686	912	47	51
28	Sonat Exploration ***	1,636	535	49	49
29	Tesoro Petroleum	1,428	1,492	6	8
30	CNG Producing ***	1,426	631	36	36
31	Seagull Energy ***	1,416	426	20	27
32	Louis Dreyfus Natural Gas	1,284	278	21	21
33	Devon Energy	1,226	388	19	39
34	Cross Timbers Oil	1,208	249	21	21
35	Mitchell Energy & Development	1,146	702	34	34
36	Vintage Petroleum Inc.	1,014	329	17	25
37	MCNIC Oil and Gas	988	207	17	17
38	Plains Resources	974	1,294	8	8
39	Range Resources	922	149	11	11
40	Pogo Producing	862	204	13	16
	Totals for the top 40 companies	428,959	398,171	3,436	5,643
	Totals for the next 160 companies	26,446	8,123	476	513
	Totals for the OGJ200	$455,405	$406,293	3,912	6,156
	Percent of top 40 to the OGJ200	94%	98%	88%	92%

*Barrels of oil equivalent reflect 5.6 mcf per barrel

** a wholly-owned subsidiary of London-based BP Amoco

*** After 1998, by May 2000, many companies above have merged or announced merging with others: Exxon & Mobil merged into ExxonMobil; BP Amoco acquired ARCO; El Paso Energy acquired Sonat, acquiring Coastal; Union Pacific merging into Anadarko; Devon acquired PennzEnergy; Seagull merged into Ocean Energy; Dominion Resources acquired CNG Producing.

Primary Source of Figure 2-4: *Oil & Gas Journal*, September 13, 1999

Figure 2-5: 1997 U.S. Petroleum Industry Employment by Industry Sector by State

(amounts in thousands)

State	E&P	Refining	Trans-portation	Whole-sale	Retail	Total
Texas	158.1	24.2	28.9	16.6	35.0	262.7
Louisiana	51.7	10.9	4.9	4.9	10.5	82.9
Oklahoma	30.4	4.4	6.4	3.7	9.1	54.0
California	21.3	17.4	10.5	9.9	56.7	115.8
New Mexico	10.0	0.7	1.5	1.4	6.0	19.6
Wyoming	8.4	0.8	1.0	0.5	4.1	14.9
Alaska	8.0	0.4	1.2	0.8	1.5	11.9
Colorado	7.8	0.5	2.4	2.3	11.2	24.3
Kansas	6.8	1.6	2.9	4.1	8.1	23.5
Mississippi	5.2	1.9	1.9	2.5	9.0	20.5
Ohio	4.5	3.8	7.3	4.7	32.6	52.8
W. Virginia	3.6	0.5	4.1	0.9	6.3	15.3
Subtotal	315.8	67.0	72.8	52.4	190.2	698.2
Other states	4.3	30.0	84.1	109.8	485.0	713.2
Total	320.1	97.0	156.9	162.2	675.2	1,411.4

Primary Source: The Independent Petroleum Association of America's *The Oil & Gas Producing Industry in Your State*, 1998

The petroleum industry is a major source of government revenue, including excise taxes and lease rents, bonuses and royalties—approximately $23.6 billion distributed to the U.S. Department of the Treasury in 1998. Federal and mineral lease revenues totaled $6 billion in 1998 as reported by the *1998 Statistical Highlights*, published by the U.S. Department of the Interior's Minerals Management Service (MMS). Royalties and similar payments to the federal government for leasing of federal lands were $5.6 billion in 1998 according to Mineral Revenue Collections, 1998, published by the MMS. The Independent Petroleum Association of America reports $3.7 billion in state taxes assessed on oil and gas production in 1998. Income taxes are also significant to E&P economics—a matter discussed in Chapter Thirty on valuation of proved oil and gas properties.

Chapter Three

ORGANIZATION OF AN E&P COMPANY

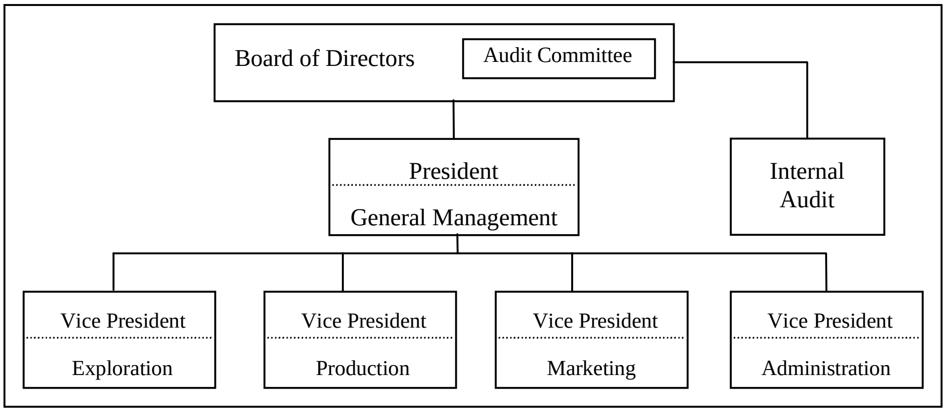
The organizational structure of a petroleum exploration and production company is important to the accountant in many ways. The structure determines how authority is delegated and responsibility is assigned, permitting accountability to be established. Accounting procedures and the flow of paperwork within the company are directly related to the company's organization. The company's accountants should be familiar with the responsibilities and organization of all departments within the company. This knowledge may be secured by experience and inquiry, augmented by the study of organization charts and company operating manuals.

The exact organization of companies in the petroleum industry varies widely, depending on size and diversity of activities. Oil and gas producers may be classified as independents or integrated companies, as described in Chapter One. Usually independents are viewed by the public as being small companies with few employees, and integrated companies are thought of as being giant companies with thousands of employees. However, there are several large oil companies that have no refining or marketing operations, and some integrated companies are small.

Obviously, size and degree of integration have much to do with a company's organization. The geographical dispersion of activities likewise is important. It is only natural that an E&P company operating in one geographical area will have closer managerial control from its top officials. As the company expands its operations geographically, top management must look to its regional and district management groups for direct control over operations and leave the home office staff to overall supervisory activities. Similarly, the integrated company requires a greater degree of delegation of authority and responsibility from top management to those directly involved in the diverse operations.

Small and medium-sized oil and gas companies have a great deal in common, especially at the executive level. There are four distinct activities common to almost all producers, and the independent companies usually build their organizations around these functions. The functions are exploration, production, marketing, and administration; the organization chart in Figure 3-1 reflects this basic structure. Appreciate that in recent years, some companies have reorganized to create small teams of geologists, petroleum engineers, accountants, and other specialists working together to manage assigned fields or geographic areas of operations.

Figure 3-1: A Basic Structure of an Independent Oil Company



The organizational structure will be examined more closely later in this chapter, but at this point a general description of the work done in each area will help in understanding the organization chart.

Typically the president of a small oil and gas company is a petroleum engineer, geologist, or geophysicist who not only serves as CEO but may also engage in closely directing exploration, development, or production activities. The small company CEO may negotiate joint venture agreements, major property acquisitions and divestitures, and financing arrangements.

The exploration department has the job of locating and acquiring oil and gas reserves. This responsibility includes the acquisition of mineral properties and geological and geophysical exploration (either through the use of company-owned equipment and personnel or through contracts with exploration support companies). Many E&P companies, even very small ones, have one or more geologists on staff, even though most companies hire outside professionals or organizations to conduct geological and geophysical (G&G) studies.

The drilling and production department (or petroleum engineering department) is responsible for exploratory drilling, development drilling, enhanced recovery operations, and field production.

The marketing department arranges the sales of the produced oil and gas. U.S. crude oil is usually sold near the well site, but now natural gas is frequently sold far from the lease to large gas consumers and to gas utilities. Under this arrangement gas pipelines provide transportation services rather than buy the gas from producers.

An administrative department may oversee various administrative functions, such as human resources, finance, accounting, tax compliance, management information systems, public relations, and legal services. The vice president of administration may be the vice president of finance and chief financial officer (CFO). Some companies break these functions into separate departments, such as a finance department headed by the CFO and containing sub-departments for treasury, accounting, and tax functions.

With this brief description of the four basic functions in the independent oil and gas producing company, let us now look at some of the details of the typical organizational structure designed to carry out these functions.

EXPLORATION DEPARTMENT

The exploration department has responsibility for locating and acquiring properties that may contain oil and gas, for conducting geological and geophysical studies, and in some companies for supervising the drilling of exploratory wells. The work of the exploration department is delegated to several sections within the department. An illustrative organization chart is shown in Figure 3-2. A brief description of the role of each section contained in that organization chart follows.

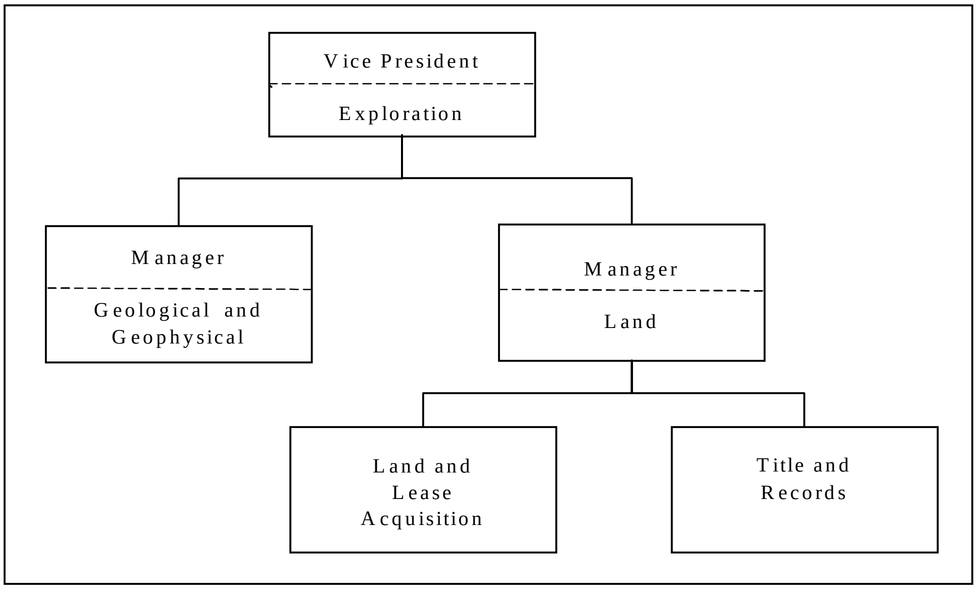
GEOLOGICAL AND GEOPHYSICAL

The G&G function is responsible for the accumulation and analysis of geological and geophysical information that will help decide (1) whether leases should be obtained in an area of interest and (2) whether and where exploratory wells should be drilled.

LAND

The land department has two major functions: acquiring mineral properties and maintaining records of properties owned. In the organization chart in Figure 3-2, this work is carried out by two divisions: the land and lease acquisition section and the title and records section.

Figure 3-2: Organization of the Exploration Department



The land and lease acquisition section is responsible for contacting landowners and others to obtain leases or other mineral rights, for advising the exploration department management on leasing activities, and for securing pooling and unitization agreements with lessees of properties adjoining the company's leases. The title and records section checks all new leases for legal propriety, maintains a complete file for all properties, and ensures the timely payment of all lease rentals as authorized.

The land department manager is called a *landman*. The term refers to a person, male or female, responsible for identifying and locating mineral-rights owners and for negotiating leases. Landman also refers to an independent lease broker. The land department may use independent lease brokers familiar with a particular state or region to represent the company in negotiating with owners of mineral and surface rights within that region and to check local title records.

DRILLING AND PRODUCTION DEPARTMENT

The overall objective of the drilling and production department is to safely manage the company's wells and production operations to maximize production value yet comply with applicable government regulations. How to best meet this objective requires petroleum-engineering skills. It should be no surprise that the department is often called the petroleum-engineering department, and its management and core personnel are typically petroleum engineers.

Larger companies may subclassify petroleum engineers into categories such as *exploitation engineers*, *reservoir engineers*, and *production engineers.*

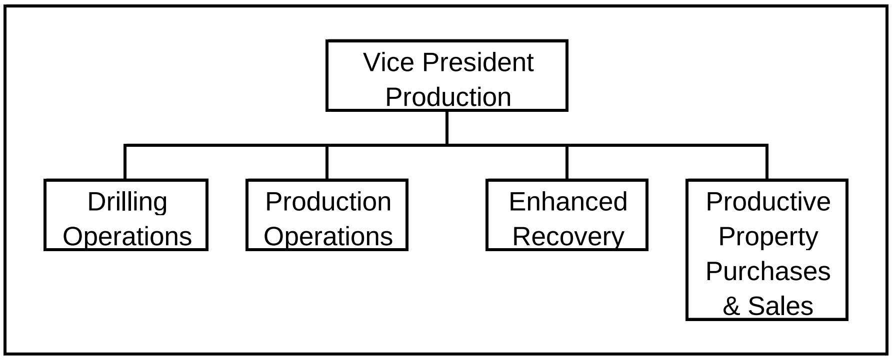
Exploitation engineers address how to best exploit a field via drilling and enhanced recovery methods. Exploitation engineers prepare or review justifications for drilling expenditures and advise on technical phases of exploitation, completion, fluid recovery, and remedial work.

Reservoir engineers study oil and gas reservoir performance, calculate recovery and profitability, and devise means of increasing ultimate recovery. They prepare the internal reports of estimated reserves by well, field, region, and company, and they work with independent engineering firms that prepare independent reports of the company's reserves.

Production engineers are concerned with both drilling and production, i.e., the every day management of producing fields, including drilling, well completion, production handling and treatment, and equipment selection and design.

Figure 3-3 shows the organization of the drilling and production department with three or four sections for a medium-sized independent company. The exploration department's geologists and geophysicists may work together with the petroleum-engineering department in evaluating drilling opportunities.

Figure 3-3: Organization of the Drilling and Production Department (aka Petroleum Engineering Department)



DRILLING OPERATIONS

In most cases, an E&P company chooses to contract its drilling operations to outside drilling contractors rather than to own and operate its own equipment. It is not unusual, however, for the owners of a producing company to organize and operate a drilling company independent of the producing company. In a company that owns and operates rigs, the drilling superintendent is responsible for all drilling activities, including oversight of rigs, tools, and equipment. The details of drilling operations are discussed in Chapter Eight.

PRODUCTION OPERATIONS

In a typical oil and gas producing company, there is a production foreman or manager for each field. In addition, there are pumpers or gaugers who measure and control production (the work of pumpers and gaugers is discussed in Chapter Eleven). Maintenance, infrequent repairs, and mechanical tasks are often carried out by specialist subcontractors.

ENHANCED RECOVERY

Some companies' organizational structures distinguish between the routine operation of fields where normal reservoir pressure suffices to drive oil and gas into the wells and unusual operations that supplement reservoir pressure drives to enhance production. Enhanced recovery includes secondary recovery methods, such as water flooding, or tertiary recovery methods, such as steam flooding. Because of their technical nature and the extremely high costs involved, secondary and tertiary projects require special attention and supervision.

PRODUCTIVE PROPERTY PURCHASES AND SALES

The function of buying and selling property with proved reserves (proved property) may be performed by a separate company department or assigned to the production department in which petroleum engineers are key to evaluating potential acquisitions and sales of proved property.

OTHER DEPARTMENT FUNCTIONS

Many *support activities* are necessary to efficiently operate an oil or gas field. For example, warehousing of materials needed in the field is necessary. Trucking and other forms of transportation must be made available. Field clerks must be assigned for carrying out routine functions in connection with handling correspondence, originating field payrolls, and completing other routine work in the field. Although field clerks may be under the direct supervision of the production manager, they frequently are under the functional supervision of the administrative department of the company.

MARKETING DEPARTMENT

Depending on the organization and size of the company, oil and gas may be sold through one or more marketing departments or marketing subsidiaries. Close coordination is required between the marketing department and the production and administration departments.

OIL MARKETING

Oil marketing is currently in a mature stage; especially compared with natural gas marketing, in that there have been no structural changes in the way oil marketing has been done for several years.

Generally, oil is marketed under 30-day contracts and sold at the lease site at *wellhead* prices *posted* (publicized) by the oil purchaser or by a major oil company.

NATURAL GAS MARKETING

Many structural changes have taken place in recent years in the way natural gas is marketed. Today, natural gas marketing is still undergoing major changes.

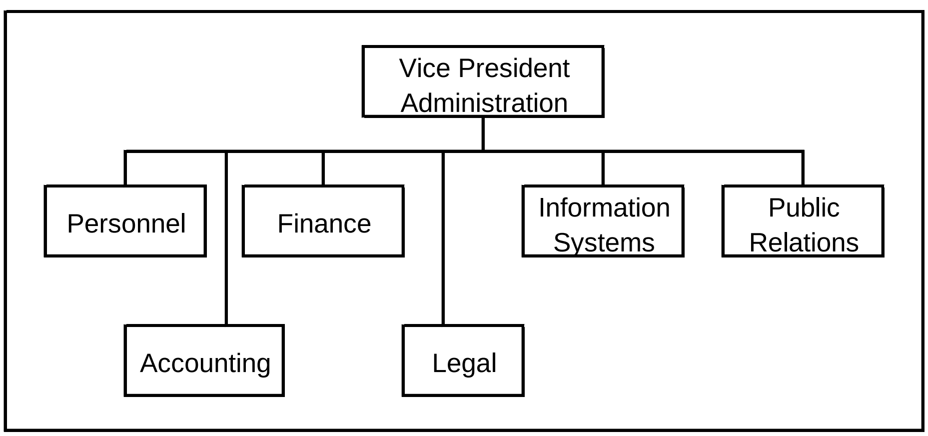
Historically, natural gas and casinghead gas (gas produced along with crude oil) were marketed to pipeline companies, which then sold the gas to others. Now gas is marketed by producers, large and small, to just about any type of gas customer other than residential.

Chapter Twelve goes into greater depth in describing how both oil and gas are marketed and the significant changes that have occurred in these processes.

ADMINISTRATIVE DEPARTMENT

The administrative department in an independent oil and gas company encompasses a variety of activities and functions and may consist of a number of *divisions*, *sections*, or *offices*. A simple organizational structure is shown in Figure 3-4.

Figure 3-4: Organization of the Administrative Department

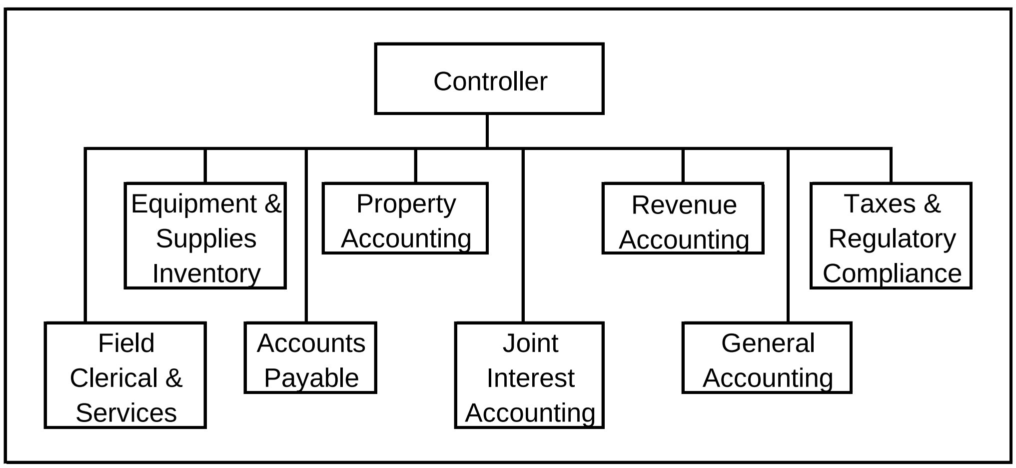


The administrative structure shown in this illustration differs little from those found in other types of businesses and is not examined in detail in this book. However, because of the importance of the organizational structure of the accounting function to the reader of this book, the activities of that function are discussed briefly.

ORGANIZATION OF THE ACCOUNTING FUNCTION

The organization of the accounting function in an independent oil and gas company is shown in Figure 3-5. The major duties of each section of the organization are summarized in the two pages that follow.

Figure 3-5: Organization of the Accounting Function in an Independent Company



FIELD CLERICAL AND SERVICES

1. Trains and supervises clerical personnel assigned to field operations.
2. Develops systems, forms, and procedures for field accounting and reporting.

EQUIPMENT AND SUPPLIES INVENTORY

1. Maintains equipment and supply inventory records.
2. Prices and records warehouse receipts, issues, and field transfers.
3. Oversees physical inventory taking.
4. Prepares reports on equipment and supplies inventory.

ACCOUNTS PAYABLE

1. Maintains accounts payable records.
2. Prepares vouchers for disbursements.
3. Distributes royalty payments.
4. Maintains corporate delegated limits of authority and verifies that disbursements are made within those limits.

PROPERTY ACCOUNTING

1. Maintains subsidiary records for
   A. Unproved properties,
   B. Proved properties,
   C. Work in progress,
   D. Lease and well equipment, and
   E. Field service units.
2. Accounts for property and equipment acquisition, reclassification, amortization, impairment, retirement, and sale.
3. Compares actual expenditures of work in progress to authorized amounts.

JOINT INTEREST ACCOUNTING

1. Maintains files related to all joint operations.
2. Prepares billings to joint owners.
3. Reviews all billings from joint owners.
4. Prepares statements for jointly operated properties.
5. Prepares payout status reports pursuant to farm-in and farm-out agreements.
6. Arranges or conducts *joint interest audits* of billings and revenue distributions from joint venture operations.
7. Responds, for the company as operator, to joint interest audits by other joint interest owners.

REVENUE ACCOUNTING

1. Accounts for volumes sold and establishes or checks prices reflected in revenues received.
2. Maintains oil and gas revenue records for each property.
3. Maintains records related to properties for purposes of regulatory compliance and production taxes.
4. Computes production taxes.
5. Maintains "Division of Interest" master files, with guidance from the land department, as to how revenue is allocated among the company, royalty owners, and others.
6. Computes amounts due to royalty owners and joint interest owners and prepares reports to those parties.
7. Invoices purchasers for sales of natural gas.
8. Maintains ledgers of undistributed royalty payments for owners with unsigned division orders, owners whose interests are suspended because of estate issues, and other undistributed production payments.
9. Prepares revenue accruals.

GENERAL ACCOUNTING

1. Keeps the general ledger.
2. Maintains voucher register and cash receipts and disbursements records.
3. Prepares financial statements.
4. Prepares special statements and reports.
5. Assembles and compiles budgets and budget reports.

TAXES AND REGULATORY COMPLIANCE

1. Prepares required federal, state, county, and local tax returns for income taxes, production taxes, property taxes, and employment taxes.
2. May prepare other regulatory reports.
3. Addresses allowable options for minimizing taxes.

INFORMATION SYSTEMS

E&P information and accounting systems vary in that the system platforms may be mainframe, mid-size, or desktop computers and that several third-party software packages are available.

An E&P information system typically employs a master file of divisions of interest (DOI file) reflecting how revenues and costs are to be shared for any one well or other accounting unit and for a designated time period of usually several months or years. The land department is typically responsible for maintaining the accuracy and completeness of the DOI file. Property, payables, revenue, and joint operations accounting will use the DOI files.

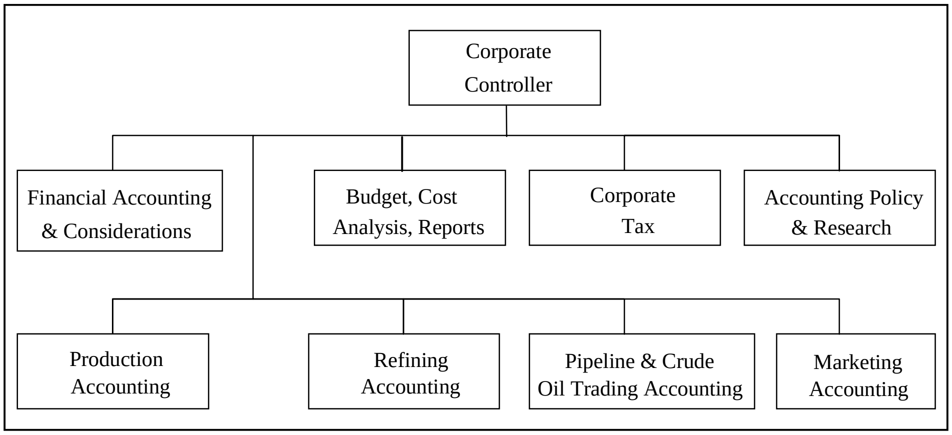
Joint ventures and divisions of interest require that a revenue information system also encompass a means of distributing the incoming sales proceeds to appropriate owners, such as the company, joint venture partners, royalty owners, and production taxing authorities. The purchasing segment of the information system must include functions for distributing the costs to appropriate parties, such as the company and joint venture partners. In other words, the revenue system must account for incoming cash as well as outgoing distribution of such revenue, and the purchasing system must account for the outgoing cash for purchases and the billing of incoming cash for others' rightful share of such costs.

The E&P information system and its chart of accounts are complicated by the need to account for (1) revenue and cost divisions of interest at a well or smaller level, (2) tax accounting that varies from financial reporting, and (3) each well and field's gross revenues and cost activity for management review and their net revenues and cost to the company for external reporting. The E&P chart of accounts is extensive and addressed in the next chapter.

GENERAL ACCOUNTING STRUCTURE OF AN INTEGRATED COMPANY

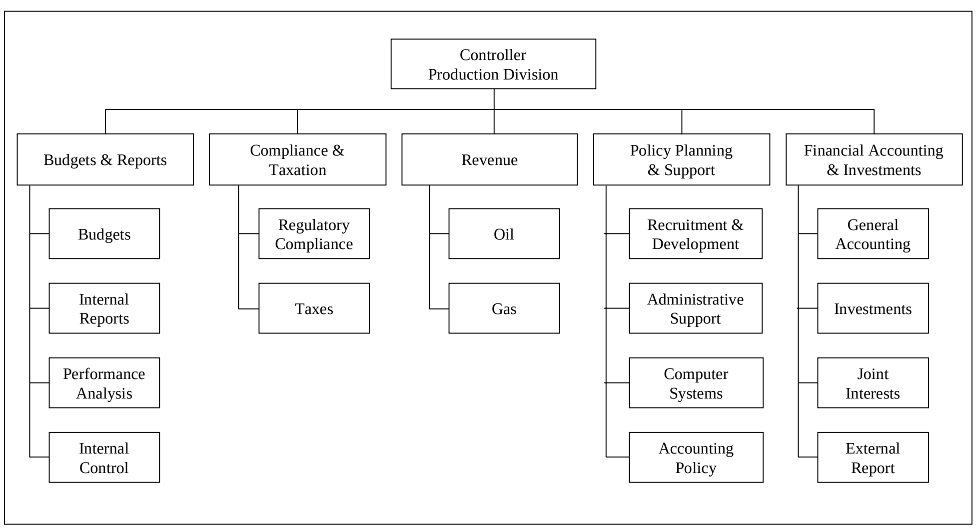
The typical accounting organizational structure for an integrated oil company includes several corporate accounting sections as well as functional accounting sections. For example, an organization chart for an integrated company's accounting function might be similar to that shown in Figure 3-6.

Figure 3-6: Organization of Accounting Functions in an Integrated Company



In turn, the organization of the accounting activities in the production division is similar to that for an independent producing company. A modified organization chart of the accounting department in the production division of an integrated company is shown in Figure 3-7.

Figure 3-7: Organization Chart of the Accounting Function in the Production Division of a Large Integrated Company



OUTSIDE ORGANIZATIONS

U.S. E&P companies are assisted by many outside entities, such as drilling rig companies and various industry associations. The remainder of this chapter lists some of the larger drilling and supply companies and introduces several industry trade associations and key government agencies that E&P management and personnel may encounter.

DRILLING AND SUPPLY COMPANIES

The lists are not intended to be exhaustive or preferential. Large drilling rig companies include the newly formed Transocean Sedco Forex (largest offshore drilling company); Nabors Industries, Inc. (largest onshore drilling company); Parker Drilling Company; and Global Marine, Inc. Large oilfield service companies include the French company Schlumberger Ltd. (pronounced SCHLUM-ber-zhay), Halliburton Company, and Baker Hughes, Inc. Privately held Koch Industries Inc. (pronounced coke) transports oil and water.

COUNCIL OF PETROLEUM ACCOUNTANTS SOCIETIES

One organization of special interest to accountants is the Council of Petroleum Accountants Societies (COPAS). The main function of COPAS is to develop educational materials as well as standardized forms that facilitate petroleum accounting, particularly for E&P joint ventures. These guidelines and forms are issued as COPAS model form accounting procedure exhibits. Virtually every U.S. E&P joint venture operating agreement includes a completed *COPAS Exhibit*, i.e., one of various COPAS model form accounting procedure exhibits that set forth certain billing, accounting, and auditing procedures and rights for the joint venture partners. COPAS also issues interpretations of the bulletins and publishes a newsletter, *COPAS Accounts*. Twenty-three chapters of COPAS are located in major oil and gas producing areas of the United States. COPAS' national office is located in Denison, Texas.

AMERICAN ASSOCIATION OF PROFESSIONAL LANDMEN

Petroleum accountants should appreciate that the AAPL develops various model industry forms, such as the AAPL Form 610 for operating agreements shown in Appendix 9. The AAPL changed its name from the American Association of Petroleum Landmen.

THE AMERICAN PETROLEUM INSTITUTE

API is perhaps the largest and single most important organization of its kind. Its purpose is to foster cooperation between industry and government; it is also involved in many research projects that collect data for the industry. Producing training films, slides, and written publications concerning the industry is part of the work performed by the API.

THE INDEPENDENT PETROLEUM ASSOCIATION OF AMERICA

As indicated by the title, the IPAA (pronounced I-P-Double A or I-P-A-A) is the national trade association for independent producers. It takes an active part, on behalf of its members, in lobbying efforts aimed at legislative and regulatory bodies. The IPAA publishes a bimonthly magazine entitled *The Petroleum Independent* along with an annual statistical publication entitled *The Oil and Gas Producing Industry in Your State*.

SOCIETY OF PETROLEUM ENGINEERS

The SPE, headquartered in Richardson, Texas, is an international technical and professional association of more than 50,000 members worldwide. It publishes the monthly *Journal of Petroleum Technology* (JPT) and produced the 1979 SPE *Standards for Estimation and Auditing of Reserves*. In March 1997 the SPE and World Petroleum Congresses approved standard petroleum reserve definitions that replaced the 1987 SPE definitions mentioned below. As discussed in Chapter Sixteen, these standard definitions did not supersede SEC definitions used for financial reporting.

SOCIETY OF PETROLEUM EVALUATION ENGINEERS

The SPEE (S-P-Double E), based in Houston, consists of a few hundred experienced reservoir evaluation petroleum engineers. Each spring the SPEE conducts a survey of fair market value parameters for oil and gas producing properties. The SPEE and the SPE developed the 1987 *Definitions for Oil and Gas Reserves*. The SPEE developed the 1988 *Guidelines for Application of the Definitions for Oil and Gas Reserves*.

REGIONAL TRADE ASSOCIATIONS

Some of the better known regional associations are:

- California Independent Producers Association (CIPA);
- Independent Petroleum Association of Mountain States (IPAMS), based in Denver;
- Mid-Continent Oil & Gas Association, based in Washington D.C.;
- Texas Independent Producers and Royalty Owners Association (TIPRO); and
- Western States Petroleum Association (WSPA), based in California.

ENERGY INFORMATION ADMINISTRATION AND U.S. DEPARTMENT OF ENERGY

The EIA, a part of the DOE, monitors the petroleum industry and provides statistical histories, forecasts, and analyses of various domestic and international petroleum industry activities.

NATIONAL PETROLEUM COUNCIL

The NPC is a group of experienced industry executives, many currently employed by petroleum companies, that advises and provides studies for the U.S. Department of Energy on petroleum issues.

U.S. DEPARTMENT OF INTERIOR'S MINERALS MANAGEMENT SERVICE

The MMS oversees the receipt of royalties for oil and gas produced on federal lands and in federal offshore areas and conducts audits of the reports and royalties from E&P companies.

TEXAS RAILROAD COMMISSION

The Commission oversees state regulations of Texas oil and gas drilling and production.

VARIOUS STATE OIL AND GAS CONSERVATION COMMISSIONS

Each state with production typically has an agency that issues permits for proposed oil and gas wells and monitors drilling and production. The well operator may be required to file monthly reports with the state commission regarding the well's production of oil, gas, and water.

Chapter Four

ACCOUNTING PRINCIPLES FOR OIL AND GAS PRODUCING ACTIVITIES

U.S. companies follow one of two methods of financial accounting for petroleum E&P activities: successful efforts or full cost.

The successful efforts method has only the cost of successful efforts capitalized as oil and gas properties. Costs of exploratory dry holes, geological and geophysical (G&G) costs in general, delay rentals, and other property carrying costs are expensed. The net unamortized capitalized costs are also amortized on unit-of-production methods whereby property acquisition costs are amortized over proved reserves and property development costs are amortized over proved developed reserves. Amortization is computed by lease (or property) or certain aggregations of properties as large as a field.

Under the full cost method all property acquisition, exploration, and development costs, even dry hole costs, are capitalized as oil and gas properties. These costs represent fixed assets, amortized on a country-by-country basis using a unit-of-production method based on volumes produced and remaining proved reserves. The net unamortized capitalized costs of oil and gas properties less related deferred income taxes may not exceed a ceiling consisting primarily of a computed present value of projected future cash flows, after income taxes, from the proved reserves.

If a company drills five exploratory wells for $1 million each and only one finds proved reserves, the successful efforts method recognizes a $1 million asset, whereas the full cost method would recognize a $5 million asset. However, investors and stock analysts should be concerned about what the proved reserves (the real asset) are worth—an amount that may be substantially different from the capitalized historical costs.

HISTORICAL BACKGROUND

Successful efforts accounting in various forms has been used for over 60 years. Full cost accounting arose in the 1950s. Today, nearly all of the 20 largest publicly traded U.S. petroleum companies use successful efforts, but of the next 150 largest, about half use successful efforts and half use full cost.[9]

By the mid-1960s many accountants and analysts had become concerned about the diverse accounting methods being used by oil and gas producers. Not only were both the full cost and the successful efforts methods being followed, but many variations in applying these two basic methods had evolved. As a result, it was difficult to realistically compare the financial statements of different oil and gas companies. The AICPA's 1969 *Accounting Research Study No. 11* (ARS 11) suggested that the full cost method of accounting should be eliminated and that only the successful efforts method should be acceptable.

The Arab oil embargo of 1973 generated intense public and Congressional interest in the oil and gas industry. This interest culminated in the Energy Policy and Conservation Act of 1975 (EPCA). Part of the Act called for the establishment of a national energy database including financial information. The Act required development of accounting practices to be used by all producers of oil and gas in reports to be filed with the Department of Energy. The Act provided that these accounting practices were to be developed by the Securities and Exchange Commission (SEC) but permitted the SEC to rely on accounting standards to be developed by the existing Financial Accounting Standards Board (FASB) if the SEC felt those standards were acceptable.

In December 1977 the FASB issued Statement of Financial Accounting Standards No. 19, entitled *Financial Accounting and Reporting for Oil and Gas Producing Companies* (FAS 19). This statement prescribed a version of the successful efforts method of accounting to be followed in determining which costs should be capitalized, established principles of accounting for conveyances of mineral interests, required comprehensive deferred income tax allocation, and required specific audited disclosures of proved reserves of oil and gas and of certain costs related to mineral activities. FAS 19 was to be effective for fiscal years beginning after December 15, 1978.

FAS 19 was repeatedly criticized by petroleum company representatives at SEC hearings in March and April 1978. In August 1978, the SEC issued *Accounting Series Release 253* concluding that neither successful efforts nor full cost accounting provided meaningful financial statements because neither recognized the value of the oil and gas reserves discovered, or reflected the discovery activity's true income, i.e., reserve value added less related discovery costs. Therefore, the SEC proposed

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[9] Primary Source: *Oil & Gas Journal's* OGJ 200 database, 1999

that a new, revolutionary method called reserve recognition accounting (RRA) be explored.

RRA would assign a value (computed under rather arbitrary rules) to proved oil and gas reserves and would reflect the changes in value of proved oil and gas reserves in earnings as the changes occurred. Until the RRA method and standards for valuing new reserves could be developed, the SEC would allow publicly held companies and other SEC registrants to use either the FAS 19 successful efforts method or a full cost method prescribed by the SEC for the audited primary financial statements. However, statements based on RRA were required to be included as supplemental information.

In December 1978 the SEC issued *Accounting Series Releases 257* and *258* on rules for successful efforts and full cost accounting, respectively. The successful efforts rules were essentially the same as those in FAS 19.

The SEC's rules appear in Appendix 1 and are referred to herein as Reg. S-X Rule 4-10.[10] In May 1996 the SEC amended Reg. S-X Rule 4-10 to delete the specific successful efforts rules, i.e., Rule 4-10(b) through (h), and add a new Rule 4-10(b) that requires those reporting entities using the successful efforts method to comply with FAS 19, as amended. The amended FAS 19 is reflected in Appendix 3 which presents the FASB *Current Text*, section Oi5 entitled *Oil and Gas Producing Activities* (Oi5).

Following the SEC's action to allow publicly held companies to use either the full cost method or the successful efforts method of accounting, the FASB, in February 1979, issued Statement of Financial Accounting Standards No. 25 (FAS 25). This statement suspended for an indefinite period most of the accounting provisions of FAS 19. FAS 25 (which applies to public and private companies) made the FAS 19 successful efforts method preferable but not mandatory. Certain provisions of FAS 19 relating to deferred income taxes, mineral property conveyances, and the disclosure requirements were substantially retained and became effective.

Publicly held companies must use either the successful efforts method in FAS 19 or the full cost method in Rule 4-10. Privately held companies technically have no required method of accounting for E&P costs. However, many such companies appear to follow the successful efforts method or the full cost method required of publicly held companies. S-X

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[10]The SEC's rules for financial accounting and reporting for oil and gas producing companies are found in Rule 4-10 of Regulation S-X (alias S-X Rule 4-10 or S-X Article 4, Section 10). Regulation App 1 is Part 210 of Title 17 of the Code of Federal Regulations. For the sake of brevity, in this book the applicable regulations will be referred to simply as Reg. S-X Rule 4-10.

Rule 4-10 is part of the GAAP hierarchy, and its full cost method is the only published comprehensive standard for full cost accounting.

FAS 25 allowed the proved reserve disclosures to be made outside the financial statements and thus be unaudited. In 1979 and again in 1980, the SEC postponed its requirement that reserve information be audited. Finally, in 1981 the SEC dropped the audit requirement.

In February 1981 the SEC announced its conclusion that RRA had shortcomings that made it inappropriate to be adopted as the primary basis of accounting. At the same time, the SEC announced that the FASB would undertake a project to develop supplemental disclosure requirements for oil and gas companies. The FASB subsequently issued FAS 69 which contained its disclosure requirements about oil and gas producing activities in November 1982. In December 1982 the SEC announced its adoption of those rules, with only minor revisions. These rules do not include an earnings summary as required under RRA but do include unaudited disclosures of the present value of future cash flows from production of proved reserves.

The controversy over two acceptable but substantially different accounting methods flared up again briefly in 1986 when the staff of the Chief Accountant's Office of the SEC recommended to the Commission that the full cost method be eliminated for publicly held companies. The Commission, however, rejected this proposal in the fall of 1986. As a result, it appears that for the foreseeable future both methods will continue to be acceptable for financial accounting and reporting.

In March 1995 the FASB issued FAS 121 on accounting for the impairment of long-lived assets (discussed in Chapter Eighteen). A long-lived asset is deemed impaired if the associated expected future cash flows (undiscounted and without interest or income taxes) are less than the asset's net book value. A loss on impairment is then recognized by reducing the impaired asset's net book value to fair market value.

FAS 121 addresses impairment of proved properties under successful efforts accounting, but not under full cost accounting. FAS 121 does not change Reg. S-X Rule 4-10, which mandates for full cost a specific, generally more conservative, impairment test. FAS 121 does not change the FAS 19 impairment rules for unproved properties.

Prior to FAS 121, informal SEC staff interpretations of generally accepted accounting principles (GAAP) held that companies using successful efforts accounting should have an impairment accounting policy and that the policy be no more liberal than limiting the oil and gas properties' aggregate net book value (less related deferred income taxes) to projected, related, undiscounted future cash flows after income taxes.

Oi5 in Appendix 3 contains the current applicable rules found in FAS 19, 25, 69, 95, 109, and 121 and in FASB Interpretation No. 36. Reg. S-X Rule 4-10 was amended in 1996 to delete its successful efforts accounting rules (i.e., old subsections (b) through (h) based on FAS 19) and adopt, by reference in new subsection (b), the successful efforts accounting rules in Oi5. The special rules for the full cost accounting method are found in Reg. S-X Rule 4-10's new subsection (c) reprinted in Appendix 1. Additional guidance is found in (I) SEC Regulation SK and SEC Financial Reporting Releases, for which excerpts are provided at the end of Appendix 1 and (II) the SEC Staff Accounting Bulletins, Topic 12, found in Appendix 2.

In the following pages, the major provisions of the successful efforts and full cost accounting methods adopted by the SEC are summarized. These two historical-cost methods will be explored more thoroughly in subsequent chapters of this book.

CLASSIFICATION OF COSTS INCURRED

The distinguishing features of the successful efforts and the full cost methods center around which costs are to be capitalized and the method by which these costs should subsequently be amortized. Reg. S-X Rule 4-10 classifies costs incurred in oil and gas producing activities into four categories: property acquisition costs, exploration costs, development costs, and production costs. Successful efforts accounting and full cost accounting for such costs are summarized in Figure 4-1 and Figure 4-2, respectively.

Support facilities and equipment, such as trucks, field service units, warehouses, camp facilities, and other facilities, may serve more than one of the four functions of acquisition, exploration, development, and production. The facilities and equipment costs are capitalized, and the related depreciation and operating costs are allocated to those functions. Depreciation of the capitalized facilities and equipment costs, as well as related operating expenses, are allocated as costs of acquisition, exploration, development, or production as appropriate. Accounting for support facilities and equipment is not peculiar to the oil and gas industry and, therefore, is not discussed in detail.

Figure 4-1: Successful Efforts Accounting for Costs

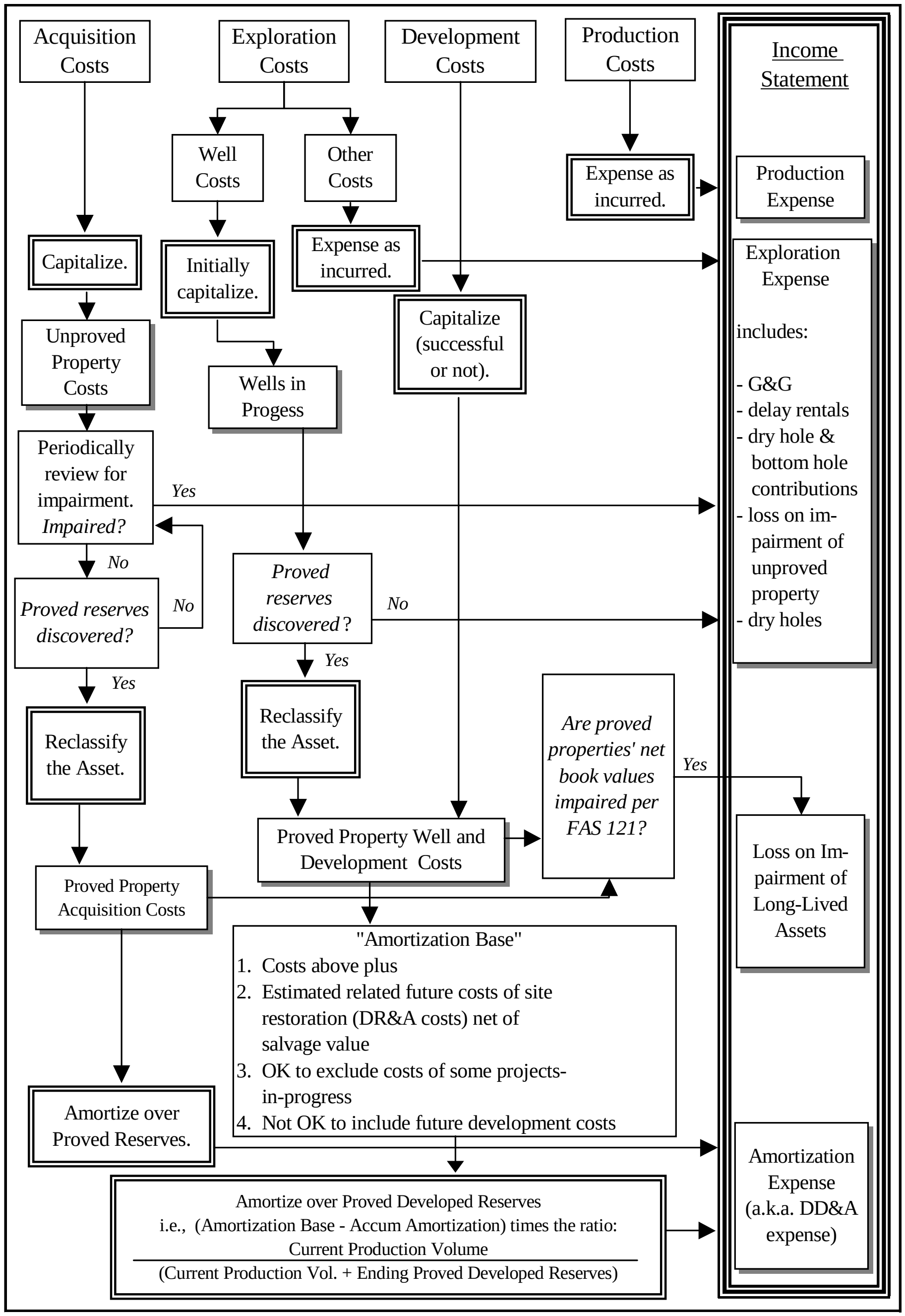
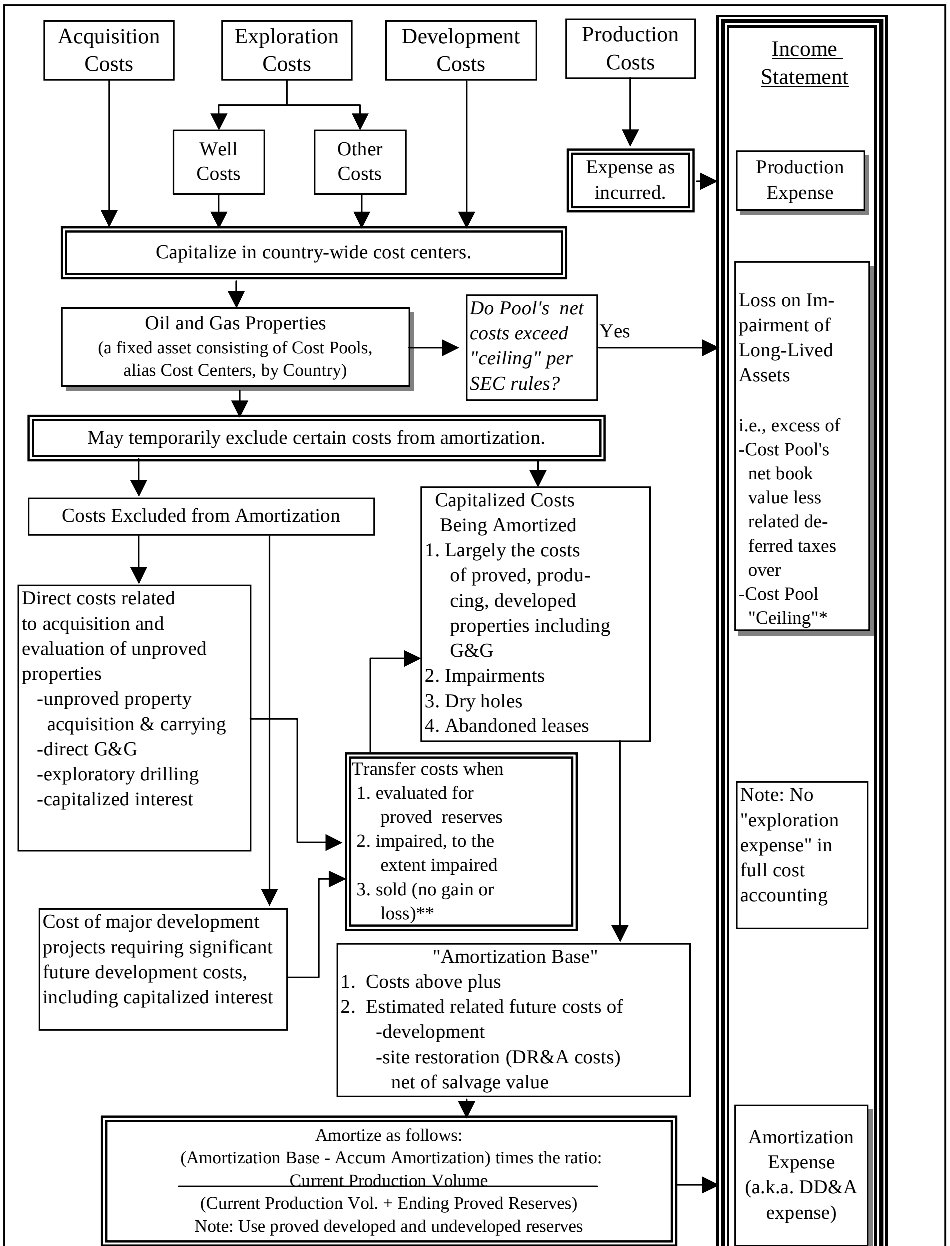


Figure 4-2: Full Cost Accounting for Costs



*Cost Pool Ceiling:
(a) a present value of projected future cash flow from proved reserves,
(b) plus costs excluded from amortization,
(c) plus the lower of cost or fair value of unproved properties in amortization base,
(d) less estimated related income tax effects, i.e., (1) the present value of income taxes on taxable income relating to proved reserves' future cash flow and (2) income taxes from hypothetically selling immediately the unproved properties and unevaluated projects at the values in (b) and (c) above

**No gain or loss unless otherwise the ratio of cost to proved reserves would significantly change.

ACQUISITION COSTS

Acquisition costs include costs incurred to purchase, lease, or otherwise acquire a property (or mineral right). They encompass lease bonuses, options to purchase or lease properties, the portion of costs applicable to minerals when land and mineral rights are purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in obtaining mineral rights.

The costs are initially capitalized as *unproved property* acquisition costs. The term *unproved property* is a confusing convention used in Reg. S-X Rule 4-10 and FAS 19 to refer to unevaluated property, i.e., property not yet evaluated as to whether it has proved reserves. Upon evaluation of the property through exploration, drilling, or lapse of the lease, if no proved reserves are found, the acquisition costs are removed from the unproved property account and become costs of abandoned or worthless property.

EXPLORATION COSTS

Exploration costs are those costs incurred in (1) identifying areas that may warrant examination and (2) examining specific areas that possibly contain oil and gas reserves, including drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred before the related property is acquired (sometimes referred to in part as prospecting costs) and after the property is acquired. Exploration costs include costs of topographical or geophysical studies and salaries and other expenses of geologists, geophysical crews, and other persons conducting these studies. Exploration costs also include the costs of carrying and retaining undeveloped properties, such as delay rentals and *ad valorem* taxes on properties. Dry-hole contributions and bottom-hole contributions also are included in exploration costs.

DEVELOPMENT COSTS

Development costs are incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering, and storing oil and gas. They include the costs of development wells to produce proved reserves as well as costs of production facilities, such as lease flow lines, separators, treaters, heaters, storage tanks, improved recovery systems, and nearby gas processing facilities.

PRODUCTION COSTS

Production costs are the costs of activities that involve lifting oil and gas to the surface and gathering, treating, processing, and storage in the field. Hence, in a broad sense, production costs include all costs of acquisition, exploration, development, and production. However, for successful efforts and full cost accounting, the term *production costs* (or *lifting costs*) refers only to those costs incurred to operate and maintain wells, related equipment, and facilities that, logically by their nature, are expensed as incurred as part of the cost of oil and gas produced. Production costs include labor to operate the wells and facilities, repair and maintenance expense, materials and supplies consumed, ad valorem taxes and insurance on property, and severance or production taxes.

CAPITALIZATION OVERVIEW UNDER SUCCESSFUL EFFORTS ACCOUNTING

Figure 4-1 shows that costs of acquiring unproved properties are initially capitalized to the Unproved Property Acquisition Costs account. Periodically (at least once a year) unproved properties are examined to determine whether their costs have been *impaired*. The impairment amount is recorded as exploration expense and credited to the Allowance for Impairment account, a contra account to Unproved Property Acquisition Costs.

Costs account to be amortized as the petroleum is produced from the property. If an unproved property is deemed to be worthless or is abandoned, its cost is removed from the Unproved Property Acquisition Costs account and is charged to Allowance for Impairment (or exploration expense, depending on the type of impairment allowance procedure followed).

Figure 4-1 shows that under the Oi5 rules, all exploration costs, except the costs of exploratory wells, are charged to expense as they are incurred, i.e., paid or obligated to be paid.[11] Costs of exploratory wells (including stratigraphic test wells) are initially capitalized (deferred) pending the outcome of the drilling operation. If an exploratory well or stratigraphic test well finds proved reserves, its costs are capitalized to the Proved

[11]Successful efforts accounting rules do not define the term *incurred*. However, FAS 71, footnote 5, defines an incurred cost as "a cost arising from cash paid out or obligation to pay for an acquired asset or service, a loss from any cause that has been sustained and has been or must be paid for."

Property Well and Development Costs account to be amortized as the related proved developed reserves are produced. If the exploratory well or stratigraphic test well proves to be dry, the accumulated drilling costs are charged to exploration expense.

Figure 4-1 also shows that all development costs, including the costs of development dry holes, are capitalized to the Proved Property Well and Development Costs account. Such costs are amortized (depreciated) as the related proved developed reserves are produced.

Production costs are expensed as incurred with two exceptions:

- Enhanced recovery injectant costs capitalized as deferred charges when related to future production (Chapters Thirteen and Thirty-One) and
- Production costs capitalized as deferred charges when associated with future gas production under the sales method of accounting for gas imbalances (Chapter Fourteen).

A portion of production costs may also be capitalized as the cost of crude oil inventory (Chapter Thirteen).

OVERVIEW OF AMORTIZATION UNDER SUCCESSFUL EFFORTS ACCOUNTING

Figure 4-1 summarizes the rules to be used in computing amortization of mineral property acquisition costs and the cost of wells, related equipment, and facilities under the successful efforts accounting prescribed by the FASB in Oi5. Mineral property costs are to be amortized as the proved developed and undeveloped reserves from the entire property are produced. Such amortization is equivalent to depreciation and, for income tax reporting, is called cost depletion. Hence, amortization of oil and gas property, well, and development costs is often called *DD&A*, meaning depreciation, depletion, and amortization. Proved property well and development costs are amortized (depreciated) as the proved *developed* reserves are produced. In computing amortization, properties in a common geological structure (such as a reservoir or field) may be combined into a single amortization center.

If both oil and gas are produced from the same property, the capitalized costs should be amortized on the basis of total production of both minerals. This requires that the two minerals be equated to an equivalent barrel or equivalent mcf (explained in Chapter One). However, if only one mineral is produced, one mineral is *de minimis*, or the minerals produced are in proportion to the reserves in the ground, a single mineral may be used in the computation.

CHART OF ACCOUNTS

In order to facilitate the discussion of accounting principles for oil and gas producing companies, we shall use the chart of accounts of Our Oil Company presented in Appendix 5. A similar but condensed chart of accounts appears in Figure 4-3. Both charts are unusual because they include the accounts needed for either the successful efforts method or the full cost method. Our Oil Company is a medium-sized independent company using the FASB's successful efforts method of accounting. However, for illustration, the charts of accounts include additional accounts needed for full cost accounting. An account unique to either accounting method is noted by an *S* or *F* in the left margin. It must be kept in mind that these charts of accounts are merely indicative of the type of accounts that might be maintained by an oil and gas company. Some of the accounts contained in the chart are peculiar to oil and gas operations and will be briefly explained. The role of these accounts and the nature of charges and credits to them will be examined more fully in subsequent chapters as specified transactions are illustrated.

Although Our Oil Company uses computerized systems, subsequent chapters occasionally illustrate the application of accounting principles and procedures through the use of manual accounting records as a pedagogical device. Each company will, of course, tailor its accounts, procedures, subsidiary records, etc., to meet its own operating and organizational needs and the philosophy of its management.

ANALYSIS OF ACCOUNTS FOR SUCCESSFUL EFFORTS ACCOUNTING

Many of the accounts found in Appendix 5 (the chart of accounts of Our Oil Company) are not unique to the petroleum industry. They are similar to those used by companies in almost all industries. However, accounts used to record transactions related to exploration, acquisition, development, and production are significantly different from accounts used for activities in other industries. Although the accounts in Appendix 5 will be explained more thoroughly throughout this book, a review at this point of the types of charges and credits made to selected accounts will help in understanding how the accounts are related to one another and how they reflect activities of the company. Since only a few accounts are unique to either successful efforts or full cost, the following analysis of accounts is presented for the successful efforts methods, followed by a brief explanation of those accounts unique to full cost.

ASSETS

Accounts Receivable

Account 121, Accounts Receivable—Gas Imbalances, recognizes a receivable for gas volumes owed from a joint venture partner or from the gas transporter (as further explained in Chapter Fourteen).

Inventories

The majority of surveyed independent E&P companies do not record the crude oil in lease tanks as inventory.[12] The overall volumes or volume fluctuations are insignificant. Hence an inventory account for crude oil is uncommon. Natural gas inventory recognition is also uncommon since gas is not stored at the lease surface, like oil, but gas injected in gas storage fields may be significant inventory for some companies.

Prepaid Expenses

These are the prepaid insurance, prepaid rents, and similar costs recognized by businesses in general. Although delay rentals are typically prepaid expenses in economic substance, industry practice is to expense under successful efforts (and capitalize under full cost) delay rentals as paid.

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[12]Source: *1999 PricewaterhouseCoopers Survey of U.S. Petroleum Accounting Practices*

Figure 4-3: Illustrative Condensed Chart of Accounts

[See Appendix 5 for an illustrative uncondensed chart of accounts with full account titles. S and F denote accounts unique to successful efforts (SE) and full cost (FC), respectively.]

Our Oil Company's Condensed Chart of Accounts

Current Assets:
101 Cash
110 Short-Term Investments
120 AR – Oil & Gas Sales
121 AR – Gas Imbalances
122 AR – Joint Interest Billings
126 AR – Other
127 Accrued Receivables
129 Allowance for Doubtful Accounts
130 Inventory – Oil
131 Inventory – Gas
132 Inventory – Supplies
140 Prepaid Expenses
142 Margin Accounts [may be long-term]

Oil & Gas Property:
211 Unproved Property Acquisition Costs
219 Impairment Allowance
221 Proved Property Acquisition Costs
S 226 Accum. Amortization of #221
F 227 Abandoned Properties
F 228 Impairment of Unproved Properties
F 229 Unsuccessful Exploration Costs
231 Proved Properties – Intangibles
S 232 Accum. Amortization of #231
233 Proved Properties – Tangibles
S 234 Accum. Amortization of #233
F 236 Accum. Amortization of Properties
237 Accum. Write-Down of Properties
F 238 Deferred Losses (Gains) on Sales
240 WIP – G&G [usually expensed for SE]
241 WIP – Intangibles
243 WIP – Tangibles
258 Support Equipment & Facilities
259 Accum. Depreciation of #258

Other Assets:
261 Other Plant & Equipment
269 Accum. Depreciation of #261
270 Notes Receivable
280 Pipeline Demand Charges

Deferred Charges:
290 Deferred Tax Asset
291 Deferred Loss on Hedging Future Production
292 Deferred Expenses Recoverable Under Foreign Production Sharing Contracts

Current Liabilities:
301 Vouchers Payable
302 Revenue Distributions Payable
304 Revenues Held in Suspense
306 Gas Imbalance Payables
307 Accrued Liabilities
320 Production Taxes Payable
330 Income Taxes Payable
335 Other Current Liabilities
360 Revenue Clearing
361 Billings Clearing

Long Term Liabilities:
401 Notes Payable
404 Production Payments, as Debt
410 Accrual for Net P&A Costs
412 Accrued Pension Liabilities

Deferred Income Taxes:
420 Deferred Income Taxes

Deferred Credits:
430 Deferred Revenue for Prepaids
431 Deferred Revenue for Volume Production Payments
432 Deferred Gains on Property Sales
433 Deferred Gains on Hedging Future Production

Stockholders' Equity:
501 Common Stock
525 Retained Earnings

Revenues:
601 Oil Revenues
602 Gas Revenues
603 NGL Revenues
610 Gain (Loss) on Hedging Revenues
620 Gain on Property Sales*
630 Other Income

Expenses:
701 Marketing Expenses
710 Lease Operating Expenses
725 DD&A
760 Loss on Impairment of Long-Lived Assets
761 Write-down of Capitalized Costs of Oil and Gas Assets
S 800 Exploration Expenses
900 G&A Expenses
920 Interest Expense
930 Loss on Property Sales*
940 Income Tax Provision

*Rare for FC

Unproved Property Acquisition Costs

Accounts 210 through 218 are used to accumulate the costs of the company's mineral rights in unproved properties (properties on which oil or gas reserves do not exist with enough certainty to be classified as proved). There may be a general ledger account for each major type of unproved mineral interest. Detailed records are maintained to record cost data for each separate property interest. These accounts are charged with applicable costs (purchase price or leasehold bonus, option costs, and incidental acquisition costs) of unproved properties acquired. Similarly, the accounts are credited with the cost of unproved properties surrendered, sold, or transferred to proved properties when proved reserves are found. If only a portion of an unproved property is sold for less than the total purchase price of the entire property, the appropriate account is credited for the proceeds up to the property's cost.

Account 210, Unproved Property Purchase Suspense, is used to accumulate costs incurred in acquiring mineral interests but to which title has not yet been acquired. The account is credited either when the interest involved is acquired or when it is ascertained that the interest will not be acquired. For example, if Our Oil Company pays a landowner $10,000 for the option to lease a mineral property within six months, Account 210 is charged with the option cost. Later, if the acreage is actually leased, the $10,000 option cost is credited to Account 210 and charged to Unproved Property Acquisition Costs (Account 211). If the acreage under option is abandoned, the $10,000 held in suspense is credited to Account 210 and is charged to exploration expense (Account 806).

The Allowance for Impairment and Amortization of Unproved Properties (Account 219) is more complex. As discussed earlier in this chapter, under Oi5 successful efforts rules, unproved properties are subjected to an impairment test that is essentially a comparison between capitalized costs and *value*. If value is less than cost, an impairment must be recognized. This impairment is recorded by a charge to expense (Account 806) and a credit to the allowance account. Impairment may be measured by comparing cost and value of individual unproved properties (this procedure *must* be used for properties whose costs are *individually significant*). Impairment of costs of groups of individually significant properties may be measured and recorded by *amortization*, based on prior experience, of the total cost of the group of properties. If impairment of individual properties is recorded, detailed records of the impairment of each individual property must be maintained. If group amortization is used, a single impairment allowance is kept for the entire group (or for each group if there is more than one group). If impairment is recorded on individual properties, Account 219 is charged with the accumulated impairment on a property that is sold, surrendered, or assigned or becomes proved (and the related unproved property cost account is credited to remove the sold property's cost). If impairment is based on a group method:

- For a property that becomes *proved*, its capitalized acquisition costs are reclassified to proved property and Account 219 is unchanged [Oi5.120];
- For *surrendered or abandoned* property, its capitalized acquisition costs are charged against Account 219 [Oi5.131]; and
- For *sold* unproved property, Account 219 is charged to the extent that sales proceeds are less than the property's capitalized acquisition costs (as illustrated in Chapter Twenty-One) [Oi5.138(g) and (h)].

Proved Property Acquisition Costs

Accounts 220 through 229 reflect costs and accumulated amortization of costs of proved mineral interests, i.e., those properties that are producing oil or gas or on which, based on known geological and engineering data, oil and gas reserves are reasonably certain to exist.

When a property is found to have proved reserves, its cost is reclassified from unproved property acquisition costs to proved property acquisition costs. For a property on which impairment has been recorded individually, only net book value (i.e., cost less the impairment allowance) is transferred to the proved property account.

Account 226 reflects the cumulative amortization of the costs of proved mineral interests. When amortization is recorded, it is charged to expense (Account 726) and is credited to Account 226. Oi5.121 provides that amortization (depletion) of proved mineral interests is to be based on production and may be computed for each separate proved property or may be computed on the total cost of properties that have been grouped together on some common geological basis, such as a field. If amortization is based on the individual property, a separate detailed record will be maintained for the amortization accumulated on that property. Similarly, if amortization is based on groups of properties, the subsidiary records must provide for accumulated amortization applicable to each group.

If amortization is based on the individual property, Account 226 is charged with the accumulated amortization on that property upon disposal.

On the other hand, if proved properties are grouped for amortization purposes, Account 226 is charged with the total cost (less any proceeds realized) when a property is disposed of.

Proved Property Well and Development Costs

Accounts 230 through 239 reflect the cost and accumulated amortization of the costs of wells, production equipment, and facilities on proved properties.

Costs of exploratory wells that do *not* find proved reserves (dry holes) are *not* capitalized but rather are charged to expense (Account 804 or 805) [Oi5.110].

Primarily for federal income tax determination, costs have been divided into two categories: Intangible Costs (Account 231) and Tangible (or Equipment) Costs (Account 233). *Intangible costs* are all those costs (such as rig rental and fuel) that have no physical existence or salvage value but are nevertheless incurred in drilling the well as further explained in Chapter Twenty-Six. For calculating federal taxable income, intangible well costs are 70 percent or 100 percent deductible when incurred, whereas tangible costs are depreciated over seven years or over the property's productive life (Chapter Twenty-Six). Because of federal tax definitions, labor costs to install casing or other equipment in the well (up through the point that valves are installed to control production) are generally considered to be intangibles and are charged to Account 231. However, costs to install flow lines, separators, tanks, and other lease equipment are classified for income tax purposes as equipment and charged to Account 233.

Accounts 232 and 234 are credited with accumulated amortization of intangibles and equipment, respectively. Amortization of well and development costs may be based on individual properties (leases) or on groups of properties if the grouping is related to geological conditions, such as a reservoir or field. Accounts 232 and 234 are charged with the amounts of depreciation accumulated on a property that is disposed of if impairment has been recorded individually. On the other hand, if group amortization is used, Accounts 232 and 234 are charged with the total capitalized costs (less proceeds from disposition) of intangibles and equipment, respectively, when a developed property included in the group is disposed of.

Account 235 may be used in lieu of liability Account 410 to recognize the additional cumulative depreciation from increasing the amortization base for estimated future plugging and abandonment costs noted in Figure 4-1.

Support Equipment and Facilities

Account 258 is charged with the capitalized costs of equipment and facilities used in oil and gas operations that serve more than one property or field or more than one function (acquisition, exploration, development, or production). Facilities such as district camps, district shops, trucks, barges, warehouses, and electric power systems are examples of field service equipment and facilities. Appropriate detailed records are kept for individual units and groups of assets.

Work In Progress

An important part of the accounting system of an oil and gas company is its work in progress accounts and the procedures related to these accounts. In some companies these accounts are referred to as *work in process* or *incomplete construction*. In Our Oil Company, Accounts 240 through 249 in Appendix 5 are used to accumulate the costs of work in progress.

These accounts are closely related to the *authorization for expenditures* system under which every major construction project or asset acquisition project is controlled by a properly approved authorization for expenditures. Thus, subsidiary accounts are kept for each project and for major cost classifications for each project.

Account 240 is used to accumulate the cost of major geological and geophysical exploration projects. Each major project is approved by an *Authorization for Expenditure* (AFE); thus, costs related to each project are properly analyzed and classified. When the project is finished, all accumulated costs are compared with the authorized amounts and are charged to expense (Account 801). Some companies do not use an AFE system for exploration projects but may nevertheless have a work-in-progress account for such activities.

Account 241, Work in Progress—Intangible Costs, is charged for all intangible costs incurred in drilling wells. Each drilling project is properly authorized and costs are accumulated for each AFE. The detailed classification of expenditures is identical to the classification used in Account 231. If an exploratory well finds proved reserves, the accumulated costs are charged to Account 231. If, on the other hand, the exploratory well is unsuccessful, accumulated costs are charged to Exploration Expenses, Account 804 or 805.

Account 244, Work in Progress—Workovers, is used to accumulate the costs of well workovers controlled by authorization for expenditures. Most companies establish some maximum amount for workover jobs that may be expensed without the use of an AFE. If the total cost of the workover job is estimated to be no more than the amount specified, the costs will be charged directly to production expense, Account 710-002. If an AFE is required, costs are accumulated for the AFE in Account 244. Upon completion of the job, accumulated costs are removed from Account 244 and charged either to a production expense account or to an asset account. A general rule is that if the workover does not increase the total productive capacity of the well, the costs are charged to expense (Account 700-002), but if the job does increase total output from the well, the costs are capitalized. Usually, the costs involved are intangible in nature, but they may include well equipment.

The remaining work-in-progress accounts (245 through 248) in Appendix 5 are self-explanatory.

Support Equipment and Facilities

Account 258 is charged with the capitalized costs of equipment and facilities used in oil and gas operations that serve more than one property or field or more than one function (acquisition, exploration, development, or production). Facilities such as district camps, district shops, trucks, barges, warehouses, and electric power systems are examples of field service equipment and facilities. Appropriate detailed records are kept for individual units and groups of assets.

Deferred Charges

Accounts 290, 291, and 292 relate to activities addressed in Chapters Twenty-Seven, Thirty-Two, and Twenty-Five, respectively.

LIABILITIES

Revenue Distributions Payable and Revenues Held in Suspense

Accounts 302 and 304 recognize liabilities to other joint interest owners or royalty owners for their share, if any, of revenues received by the company on the venture's behalf. Suspended revenues may relate to disputed or unknown ownerships or to nominal payables paid out quarterly or annually.

Production Payments and Prepaids

Production payments are obligations, as production occurs, to either (1) deliver specified production volumes or (2) pay specified cash amounts. A company may agree to make future production payments in return for receiving assets now, such as cash or producing property. A receipt of cash in exchange for a production payment payable in oil or gas volumes (a *Volume Production Payment*, *Volumetric Production Payment*, or VPP) is deemed to be the sale of a mineral interest; sales proceeds are credited to Account 431, Deferred Revenue for Volume Production Payments. The account's credit balance is proportionately reduced, and revenue is credited, as the VPP volumes are delivered.

Receipt of cash in exchange for future production payments payable in specified cash amounts is a borrowing; a cash account is debited and Account 404, Production Payments Payable as Debt, is credited.

Occasionally cash is received in exchange for a production payment created from unproved mineral interests whereby the cash is credited to the unproved property account. Chapter Twenty-Two provides further explanation of accounting for production payments.

Account 430, Deferred Revenue for Prepaids, reflects prior cash received for an obligation to deliver oil or gas in the future regardless of company oil and gas production. As explained in Chapter Twenty-Two, the prepaid transaction is not the sale of a mineral interest since the delivery obligation may require the company to purchase the oil or gas for delivery under the obligation.

Clearing, Apportionment, and Control Accounts

Many expenses are of such a nature that they cannot readily be charged to a single drilling operation, an individual lease, or other individual operating functions. Therefore, they must be accumulated and subsequently distributed to other expense accounts or asset accounts. The accounts in which such costs are accumulated are usually referred to as clearing and apportionment accounts. Clearing accounts generally are used to accumulate expenses during a given period (usually a month); at the end of the period, the balance of the account is allocated to other accounts on some predetermined basis. An apportionment account is also used to accumulate costs, but credits to the account are made on the basis of fixed rates for services rendered. The balance of an apportionment account, which should be small if rates have been properly established, will normally be carried forward from month to month but will be closed to miscellaneous expense or miscellaneous income at the end of the year.

Control accounts (360 and 361) facilitate accounting controls generally over joint venture revenues and billings received and processed. E&P companies do not normally invoice for oil and gas sales and, therefore, normally accrue estimated receivables rather than record an exact accounts receivable. So when the net sales proceeds are received, the E&P company should use as much internal information as practical to check the accuracy of the oil (or gas) purchaser's calculation of proceeds. The remittance might be reviewed for accuracy by inputting from the payor's remittance advice the well's identity, the sales month, the gross production volume, and the cash paid to the company. For example, assume that $10,000 is paid to the company for one well's oil production in June and assume that the company's computer-generated entries were as follows:

101	Cash	10,000	
	360 Revenue Control		10,000
360	Revenue Control*	11,040	
710.009	Production Taxes	960	
	601 Oil Revenue		12,000

*Computer calculated as 5,000 barrels sold x $20/bbl [price per company pricing file] x 12% net revenue interest [per the company's master division of interest file] x (1 - 8% production tax rate [per company tax rate file]).

The control account indicates a $1,040 discrepancy in the amount remitted, perhaps because of a payor's error or company error as to the well identity, sales month, volume, price, net revenue interest, or production tax rate. The balance in the control account alerts the company to identify the error and have it corrected, which brings the control account balance back to zero. Normally, control accounts have nominal balances. Some companies may classify revenue control accounts in the accounts receivable section of the chart of accounts.

REVENUES

The revenue accounts unique to oil and gas production (accounts 600 through 607) are designed to reflect the company's share of revenues from each major type of mineral interest owned. Revenues applicable to mineral interests owned by other parties (for example, revenues applicable to a royalty interest owned by the lessor in a lease operated by the company) should not be included in revenue.

EXPENSES

Most of the expenses peculiar to an oil and gas exploration and production company are found in accounts 700 through 806. The direct expenses of operating producing oil and gas properties are charged to Account 710, Lease Operating Expenses. The classification of lease operating expenses varies from company to company, but in every case the classification is designed to assist in their control. Note that depreciation, depletion, and amortization are not included in Account 710 but are separately shown in accounts 725 through 749. The items in Account 710 are generally referred to as *lifting costs*. Costs are accumulated for each mineral property so that net income from each property may be computed for management oversight and income tax accounting.

OVERVIEW OF FULL COST ACCOUNTING

The full cost method regards all costs of acquisition, exploration, and development activities as being necessary for the ultimate production of reserves. All of those costs are incurred with the knowledge that many of them relate to activities that do not result directly in finding and developing reserves. However, the company expects that the benefits obtained from the prospects that do prove successful, together with benefits from past discoveries, will be adequate to recover the costs of all activities, both successful and unsuccessful, and yield a profit. Thus, all costs incurred in those activities are regarded as integral to the acquisition, discovery, and development of reserves that ultimately result from the efforts as a whole and are, thereby, associated with the company's proved reserves. Establishing a direct cause-and-effect relationship between costs incurred and specific reserves discovered is not relevant to the full cost concept.

THE COST CENTER

Capitalized costs are aggregated and amortized by *cost center*. Under the SEC's full cost rules, cost centers are established on a country-by-country basis. A rigid interpretation of this rule would prohibit the combining or grouping of countries in a geographical area. For example, it would be improper to combine, as *North Sea operations*, activities in the Norwegian, U.K., Dutch, and Danish territorial areas.

COSTS TO BE CAPITALIZED

Reg. S-X Rule 4-10(c)(2) specifies the costs to be capitalized under full cost:

> **Costs to be capitalized.** All costs associated with property acquisition, exploration, and development activities (as defined in paragraph (a) of this section) shall be capitalized within the appropriate cost center. Any internal costs that are capitalized shall be limited to those costs that can be directly identified with acquisition, exploration, and development activities undertaken by the reporting entity for its own account, and shall not include any costs related to production, general corporate overhead, or similar activities.

Under these rules, all geological and geophysical costs, carrying costs (such as delay rental and maintenance of land and lease records), dry-hole and bottom-hole contributions, costs of exploratory wells (both dry and successful), costs of stratigraphic test wells, costs of acquiring properties, and all development costs are capitalized. When leases are surrendered or abandoned, their costs remain a part of the net capitalized costs of the cost center.

Since all costs incurred in each country are capitalized and treated as applicable to all minerals within that country, individual properties and assets conceptually lose their identities. Thus a single oil and gas asset account (or an account with a similar title) for each country could be used to accumulate the costs in that country. For example, a company with operations in four countries might maintain accounts as follows:

Oil and Gas Assets—United States
Oil and Gas Assets—Canada
Oil and Gas Assets—Norway
Oil and Gas Assets—Trinidad

Even if all oil and gas assets in a country are lumped into a single account, detailed records of acquisition costs, drilling and development costs, etc., must be maintained for federal income tax purposes. Therefore, companies using the full cost method must effectively maintain subsidiary records of individual unproved properties and individual proved properties in the way described in this chapter for companies using the successful efforts method. In addition, the method of accounting used does not alter the procedure necessary for internal control of operations. Thus, the detailed records kept by a full cost company are likely to be very similar to those of a company using the successful efforts method. Basic accounting procedures and forms, such as the AFE used by the full cost companies, are likely to be identical to those used by successful efforts companies.

Costs to be amortized as DD&A include the sum of three costs. First, capitalized costs, net of accumulated amortization, are included. However, all unevaluated acreage and unevaluated exploratory costs, as well as significant investments in major development projects in progress, may be excluded from the amortization computation (Figure 4-2). Second, estimated future development costs applicable to proved undeveloped reserves, and third, estimated dismantling and abandonment costs, net of salvage, are added to the basis for amortization (Figure 4-2).

Unproved properties and exploratory costs that are excluded from the amortization base are to be periodically assessed for impairment until it can be determined whether proved reserves are attributable to the properties. If impairment is indicated, the amount of impairment should be included in the amortization base. Unevaluated costs applicable to properties that are not individually significant may be placed in a group (or more than one group) and *amortized* into the amortization base.

Amortization under full cost is on the unit-of-production basis using physical units of proved oil and gas reserves converted to a common unit based on relative energy (Btu) content, unless economic circumstances indicate that using gross revenue dollars rather than physical units results in a more appropriate basis for computing amortization.[13]

Reg. S-X Rule 4-10 puts a ceiling or limitation on capitalized costs for companies using the full cost method. For each cost center (country), the net unamortized costs, less related deferred income taxes, shall not exceed the sum of (a) the present value at a 10 percent discount of *future net revenues* of proved reserves, *plus* (b) unproved property costs and preproduction costs not being amortized, *plus* (c) the lower of cost or

[13]Per Reg. S-X Rule 4-10(c)(3)(C)(iii) (Appendix 1) and Topic 12 F (Appendix 2).

estimated fair value of unproved properties included in costs being amortized, *less* (d) income tax effects related to differences between (1) the sum of (a), (b), and (c) and (2) the tax basis of the properties involved.[14] Any excess is charged to expense.

ACCOUNTS FOR FULL COST ACCOUNTING

As shown in Figure 4-3 and Appendix 5, few accounts are unique to full cost accounting.

Since all costs incurred in exploration, acquisition and development activities are capitalized, there are no exploration expense accounts for a full cost company.

When an unproved lease is abandoned as unsuccessful, related costs are moved from the Unproved Property Acquisition Costs account and charged to the appropriate cost center's Account 227 as a capitalized cost of unsuccessful efforts.

Exploration costs and similar carrying costs are allocated to individual unproved properties or proved properties and become part of the cost of individual properties. Some costs, such as regional G&G costs, cannot be reasonably allocated and may simply be charged to Account 229, Unsuccessful Exploration Costs. Account 236 is used to accumulate amortization as a single figure for each cost center (each country), and Account 725 reflects this charge. Thus there is no separate allowance for amortization for each type of capitalized cost.

Under the full cost method, a *ceiling* is placed on capitalized costs. Any write-down required because a cost center ceiling is less than net capitalized costs is charged to Account 761 and credited to Account 237 with appropriate adjustment of deferred income taxes.

No gain or loss is customarily recognized on the sale or abandonment of oil and gas assets under the full cost method.

Chapter Nineteen more fully addresses these issues in applying the full cost method.

OVERVIEW OF INCOME TAX ACCOUNTING

Financial accounting under successful efforts or full cost differs from the accounting required to compute taxable income for determining

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[14] The tax effects formula above is the *short-cut* approach found and clarified in Appendix 2.

regular income tax and alternative minimum income tax under the Internal Revenue Code. Key aspects of income tax accounting are as follows:

- Intangible drilling costs (IDC) for U.S. wells may be deducted when incurred except that certain integrated companies must capitalize 30 percent of the intangibles for amortization over 60 months.
- Taxpayers electing initially to deduct IDC currently have an additional annual election to capitalize all or a portion of the IDC incurred in that tax year. The capitalized portion is amortized ratably over a 60-month period beginning in the month the costs are paid or incurred.
- Dry hole costs for exploration and development wells are fully deductible when the well is determined to be dry.
- Except for certain integrated companies, a taxpayer producing oil or gas may get a *percentage depletion* deduction. It generally equals 15 percent of well-head revenue for up to 1,000 equivalent barrels per day of production sold but is limited by property to 100 percent of taxable income and limited by taxpayer to 65 percent of the taxpayer's taxable income before deducting depletion. The taxpayer's recorded depletion deduction is the greater of the calculated percentage depletion deduction or a *cost depletion* amount. Cost depletion is similar to acquisition cost amortization under successful efforts.
- Unproved property impairments are not deductible; unproved property costs are deducted when the property is abandoned.
- Proved property impairments and ceiling write-downs are not deductible.
- Tangible well and development costs are depreciated, generally over seven years, but may be depreciated over proved reserves using the unit-of-production method.

Chapter Twenty-Six addresses these and other aspects of determining income taxes for an oil and gas exploration and production company.

Chapter Five

GEOLOGICAL AND GEOPHYSICAL EXPLORATION

For most companies engaged in oil and gas activities, exploration costs represent a substantial portion of annual expenditures. This chapter describes the scope and nature of geological and geophysical exploration costs. Chapter Six examines the accounting principles and procedures to be used in accounting for such costs.

THE NATURE OF EXPLORATION COSTS

The Securities and Exchange Commission (SEC) in REG. S-X Rule 4-10(a)(15) has succinctly defined exploration costs as follows:

> Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:
>
> (a) Studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are often referred to as geological and geophysical or *G&G* costs.
> (b) Costs of carrying and retaining undeveloped properties, such as delay rentals, *ad valorem* taxes on properties, legal costs for title defense, and the maintenance of land and lease records.
> (c) Dry-hole contributions and bottom-hole contributions.
> (d) Costs of drilling and equipping exploratory wells.
> (e) Costs of drilling exploratory-type stratigraphic test wells.

Of these five types of exploration costs, G&G costs are explained in this chapter. The other types of exploration costs are explained in Chapters Seven and Eight.

To explain the nature of G&G exploration, this chapter describes first the current theories on the origin of petroleum; second, how petroleum becomes *trapped* or pooled within rock formations; and last, the several types of G&G exploration methods.

ORIGIN OF PETROLEUM

The earth is made up of a core over 4,000 miles in diameter surrounded by the earth's mantle, which is approximately 2,000 miles thick. The earth's surface is underlain by the lithosphere, a relatively thin layer, some 125 miles in thickness, that is composed of the crust and upper mantle. Commercial oil and gas are found only in the crust of the earth. *Geology* is the science that studies the planet earth—the materials of which it is made, the processes that act on these materials, the products formed, and the history of the planet and its life forms since its origin. Most geological studies are focused on aspects of the earth's crust because it is directly observable and is the source of energy and minerals for today's modern industrial societies. *Geophysics*, the science that studies the earth by quantitative physical methods, is used in conjunction with geology in the exploration for oil and gas.

PLATE TECTONICS

Most geologists believe the earth initially formed from molten rock, or magma, and cooled into solid *igneous rocks*. During the cooling and contraction processes, some rock solidified beneath the surface. *Plate tectonics*, now a widely accepted theory regarding mountain formation and the development of oceans, suggests rock on the surface cooled and developed into rigid *lithospheric plates*. There are now 20 such plates that slowly drift across the relatively dense mantle. As plates bump into and slide past each other along plate boundaries, many geological activities occur, such as earthquakes, volcanoes, and increased erosion and sedimentation. Plate boundaries can be one of three types: compressional, extensional (rift), or transverse (strike slip or wrench). Compressive boundaries occur where plates collide head-on. The Himalayas formed in such a fashion when the Indian plate collided with the Eurasian plate. Rift boundaries occur when plates are pulled apart. The Atlantic Ocean is underlain by a rift boundary formed as the North American plate moved away from the African plate. Transverse boundaries occur when plates slide past each other, like two conveyor belts moving in opposite directions. The San Andres fault is the most well known example of a transverse or strike-slip boundary. The history of earthquake activity along the San Andreas fault is well known and demonstrates the intense geological forces that can develop along plate boundaries.

THE ORIGIN OF ROCKS AND PETROLEUM RESERVOIRS

As plates have migrated over geological time, the surface of the earth has changed dramatically with the plates sometimes gathering into enormous supercontinents and at other times breaking up into smaller land masses; these changes are continuing today. Three types of rocks are generally discussed. *Igneous rocks* discussed above, result from cooling and solidification of molten rock, or magma. *Sedimentary rocks,* such as sandstone, developed as a direct result of erosion, transport, and deposition of pre-existing rock. Eroded particles are carried to low areas and are deposited into sedimentary layers through the action of wind and water. Under appropriate conditions, sedimentary rocks, such as limestones, can be directly precipitated from water by either living organisms or changes in water chemistry. *Nearly all significant oil and gas reservoirs are found in sedimentary rocks.*

Metamorphic rocks develop when igneous or sedimentary rocks are subjected to heat and pressure resulting from the weight of overlying rocks and/or tectonic stresses. With enough heat, pressure, and time, sedimentary shale and sandstone can be converted into metamorphic slates and quartzite. As extreme heat and pressure are increasingly applied, these slates and quartzites are recycled into magma that will ultimately cool into igneous rock. The accumulation of oil or gas in igneous or metamorphic rocks is very rare; however petroleum can be reservoired in these types of rock under certain albeit rare conditions. The extreme heat and pressure associated with these types of rocks drives off or burns any organic material or hydrocarbons.

The various changes in the earth's crust do not, by themselves, explain the evolution of oil and gas. Over the last two centuries, two theories—the inorganic theory and the organic theory—have been advanced to explain the formation of oil and gas. Although no one theory has achieved universal acceptance, most scientists and professionals believe in an organic origin of petroleum.

INORGANIC THEORY

The inorganic theory recognizes that hydrogen and carbon are present in natural form below the surface of the earth (diamonds, for example, indicate the presence of carbon in the earth's mantle). Different related theories explain the combination of the two elements into hydrocarbons. These include the alkali theory, carbide theory, volcanic emanation theory, hydrogeneration theory, and the high temperature intrusion theory. Except for the intrusion theory, most of the inorganic theories have been largely discounted. The intrusion theory argues that high temperatures applied to carbonate rocks can produce methane gas and/or carbon dioxide. This theory applies only to gas, not to the heavier hydrocarbons (oil).

ORGANIC THEORY

Based on abundant direct and indirect evidence, most scientists accept the organic theory of evolution of oil and gas. The basic premise is that oil and gas are formed from chemical changes taking place in plant and animal remains. Most hydrocarbons are believed to be derived from tremendous volumes of plankton, algae, and bacteria common in ocean basins and lakes.

According to geological research, the earth was barren of vegetation and animal life for roughly one half of an estimated five billion years of the earth's existence. Approximately 600 million years ago, an abundance of life in various forms began in the earth's oceans. This development marks the beginning of the Cambrian period in the Paleozoic era. Nearly 200 million years later (in the Devonian period), vegetation and animal life had spread to the landmasses. The Paleozoic, Mesozoic, and Cenozoic eras have been labeled as successive and definitive geological time periods by geologists, which brings us up to the present. These time periods are shown in Figure 5-1.

Through the process of erosion and transportation, sediments are carried from the land down the rivers and, together with some forms of marine life, settle into the ocean floor. The sedimentation process can be observed even within an individual's lifetime. For example, the delta area at the mouth of a large river is formed by sedimentation. Layer after layer of silt, mud, particles of sand, and plant and animal life are deposited on the ocean floor, with a great portion of the plant and animal life coming from the ocean itself.

Figure 5-1: Geologic Time Periods

Era	Period	Approx. Duration in million yrs.	Indicative New Life Forms
Cenozoic "Modern Life"	Quaternary	3	Large mammals
	Tertiary	63	
Mesozoic "Middle Life"	Cretaceous	71	Large Dinosaurs
	Jurassic	54	
	Triassic	35	
Paleozoic "Ancient Life"	Permian	55	Early Reptiles, Amphibians, and Fish
	Carboniferous	65	
	Devonian	50	
	Silurian	35	
	Ordovician	70	
	Cambrian	70	
Crypotozoic or Precambrian		4,000	Bacteria, Algae, and Jellyfish

Approximate age of the earth 4,600,000,000 years

For oil and gas to form, it is essential that the aerobic bacterial action cease because normal decomposition in the presence of oxygen destroys both the organic material and hydrocarbons. In addition, there must be an impervious layer both below and above the accumulation of organic material to prevent the hydrocarbons from migrating vertically once the material has been buried deeply enough to commence hydrocarbon generation.

Accordingly, under the organic theory, it is essential that organic rich sediment be protected from oxidation or decay to preserve its potential to generate hydrocarbons upon subsequent burial, commonly to depths of about 9,000 feet to generate hydrocarbons. Anaerobic bacteria in the sediment aid in breaking up the organic material and releasing oxygen, nitrogen, phosphorus, and sulfur from the organic material, leaving the balance with a much higher percentage content of hydrogen and carbon and, thus, a more petroleum-like composition.

With increasing sedimentation, higher pressures and temperatures are created. As a result, sedimentary sandstones, shales, limestones, and dolomites are formed. These rocks have open pore spaces between individual grains. With increasing pressure and temperature, compaction forces hydrocarbons that had been formed from plant and animal remains into the rock's pore spaces. At the same time, the overlying or trapping mud is compacted into an impervious layer forming a seal to prevent hydrocarbons from leaking to the surface. If the seal is inadequate, seeps occur. Seeps at the surface are often used as indicators of potential hydrocarbon reservoirs in the subsurface. Hydrocarbons are known to have been preserved for hundreds of millions of years such as the Late Precambrian petroleum in eastern Siberia. Some areas are generating hydrocarbons today. The process of hydrocarbon formation is undoubtedly continuing, but much more slowly than is the rate of consumption of hydrocarbons.

Evidence supporting the organic theory of oil and gas formation includes the facts that (1) sedimentary beds are rich in organic matter, (2) some of the chemical components of oil are the same as those found in plants and animals, and (3) the chemical composition of oils and gases derived from so called source rocks match the observed composition of oils and gases in nearby reservoirs. The matching of oils and source rocks has become increasingly sophisticated to the point that certain chemical characteristics of oils called biomarkers point to the specific conditions of formation of the source rocks such as its climate and organic make-up. Numerous examples of petroleum generated within source rock (such as coalbed methane) clearly link source rocks and hydrocarbons. In addition, the close association of most significant conventional oil and gas fields with sedimentary rocks of marine origin provides indirect evidence regarding the organic theory of oil and gas.

MIGRATION AND TRAPPING OF HYDROCARBONS

All oil and gas fields require several elements working together to form an accumulation. The combination of adequate *source rocks* to generate the petroleum, an adequate *reservoir* to accommodate the petroleum and an impermeable *seal* to prevent the petroleum from leaking are critical to forming oil and gas fields thus forming a *trap* for hydrocarbons. All of these elements may exist in a region and yet remain unproductive if the rocks have not been buried to a sufficient depth for source rocks to commence generation of petroleum, i.e., to form a petroleum system.

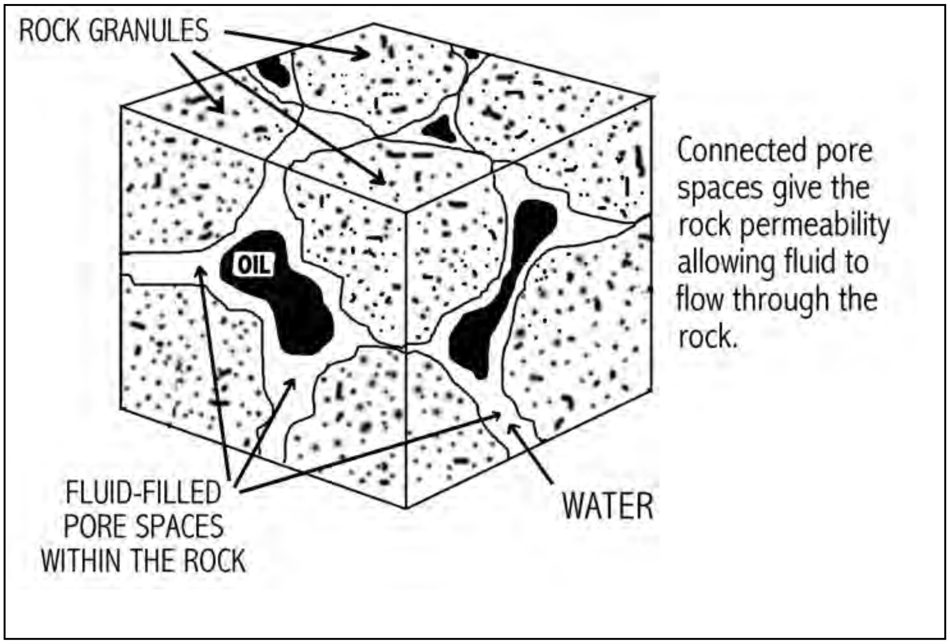
Source rocks are commonly marine or lacustrine shales, coals, or other fine-grained sedimentary rocks that contain abundant organic material to provide a source of hydrocarbons. Generally marine and lacustrine source rocks generate oil whereas coal source rocks commonly generate natural gas. A *seal* is an impermeable rock layer that will not allow vertical fluid migration. In contrast, a *reservoir* is a rock formation with adequate porosity and permeability (defined below) to allow oil and gas to migrate to a well bore at a rate sufficient as to be economic. A *trap* is a three-dimensional arrangement of the source, seal, and reservoir rocks that results in a concentrated hydrocarbon accumulation. To search for new oil and gas fields, geologists and geophysicists devote their efforts to understanding the distribution of rocks that could be sources, seals, and reservoirs in an attempt to develop locations for potential traps within petroleum systems.

While it can be shown that oil and gas are formed through the sedimentary process, this does not necessarily mean that the oil and gas have remained in the source beds or places of origin. The formation of oil and gas deposits involved four main steps. Initially, there was an accumulation of source material, particularly in fine-grained sediments on top of an impervious layer. Then came partial decomposition caused by anaerobic bacterial action within the source beds. Pressures are believed to have caused a primary migration of the oil and gas from the source beds to reservoir rocks with characteristics favorable to their accumulation. Common characteristics of these rocks include *porosity* and *permeability*. Porosity is a measurement of the volume of pores, or tiny open spaces, between individual granules making up the rock; none of the sedimentary rocks are completely solid. It is within the pore spaces that the oil and gas initially accumulated, together with some water called *connate water*. The characteristic of porosity is illustrated in Figure 5-2.

The pore spaces may constitute up to 30 percent of the volume of the reservoir rocks that are relatively close to the surface. As depths increase, the porosity of the formation tends to decrease as the result of compaction from the weight of the overlying layers of sediment.

Permeability measures the relative ease with which the oil and gas can flow through the rocks and is expressed in *millidarcies*. The flow of oil and gas through a reservoir takes place in microscopic channels between pore spaces. In some cases fractures are also present that provide greater permeability. If there is high permeability, oil and gas can move through the formation with relative ease. Low permeability will decrease or even block the movement of fluids through the formation.

Figure 5-2: Porosity within a Reservoir Rock



We can assume that oil and gas are formed over large areas in the presence of formation water (connate water similar to marine brines). The natural tendency of lighter oil and gas is to rise above the water through the mechanism of buoyancy, migrating upward within a given sedimentary bed until they reach an impermeable layer or seal. In some instances, oil and gas migrate directly to the reservoir area. More often, however, movements in the earth's crust caused additional shifting, folding, bends, and fissures, and a secondary migration of the oil and gas took place through porous layers until another impermeable seal was reached. This may occur when an area is subjected to new tectonic forces.

CLASSIFICATION OF OIL AND GAS TRAPS

There are many classification schemes for different types of hydrocarbon traps. Although a thorough classification of trap styles is beyond the scope of this book, some discussion is necessary to better understand the nature of oil and gas accumulations. Traps differ in size, shape, and type primarily because of the manner in which they were formed. A simple classification for conventional oil and gas includes (1) *structural traps*, (2) *stratigraphic traps*, (3) *truncation traps*, and (4) *combination traps*. Unconventional petroleum accumulations commonly cross lithologic boundaries and can extend across very wide regions. The likelihood of finding hydrocarbons in conventional traps is higher than for unconventional accumulations. The risk in unconventional hydrocarbon accumulations is that the producing rates may be low and may not be economic.

Structural traps were formed by geological structures resulting from horizontal and/or vertical movement in the earth's crust, directly or indirectly related to plate motions. The most common types of structural traps are *anticlines*, *faults*, and *domes*.

Anticlines are formed by folding of the strata into a dome as the result of upthrusts from below or by lateral compressive forces. Anticlines, which retain hydrocarbons, are covered with a cap rock or an impervious layer. The anticline was filled by the movement of water, oil, gas, or some combination of these through porous strata until movement was halted by the seal or cap rock. Figure 5-3 is a simplified illustration of an anticline. Historically, anticlines have been the most significant traps containing oil and gas reserves. It has been estimated that approximately 80 percent of the world's oil has come from anticlines. An example of an anticlinal reservoir is the giant Sadlerochit reservoir at Prudhoe Bay field in Alaska.

A *fault* is another type of structural trap. Faults are formed by the breaking or shearing of strata as the result of significant shifting or movement of the earth's crust. When faulting occurs, the relative placement of the strata is changed to the extent that a porous bed holding hydrocarbons can be sealed off by an impermeable formation, thus establishing a seal or trap. Most individuals think of faults in connection with earthquakes, yet few realize that these shifts have resulted in the accumulation of oil and gas deposits. A typical fault is illustrated in Figure 5-4. Faults provide traps and important pathways for petroleum migration.

Figure 5-3: Anticline

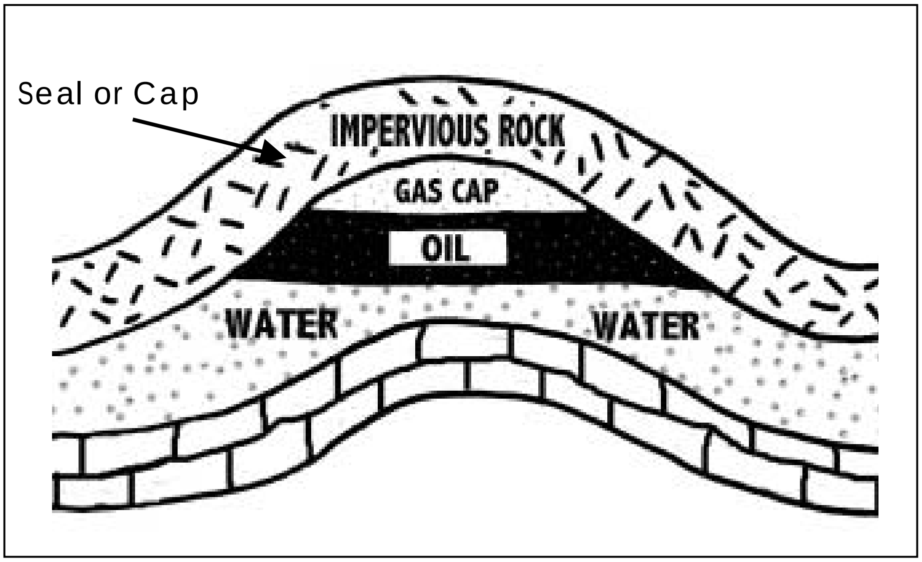
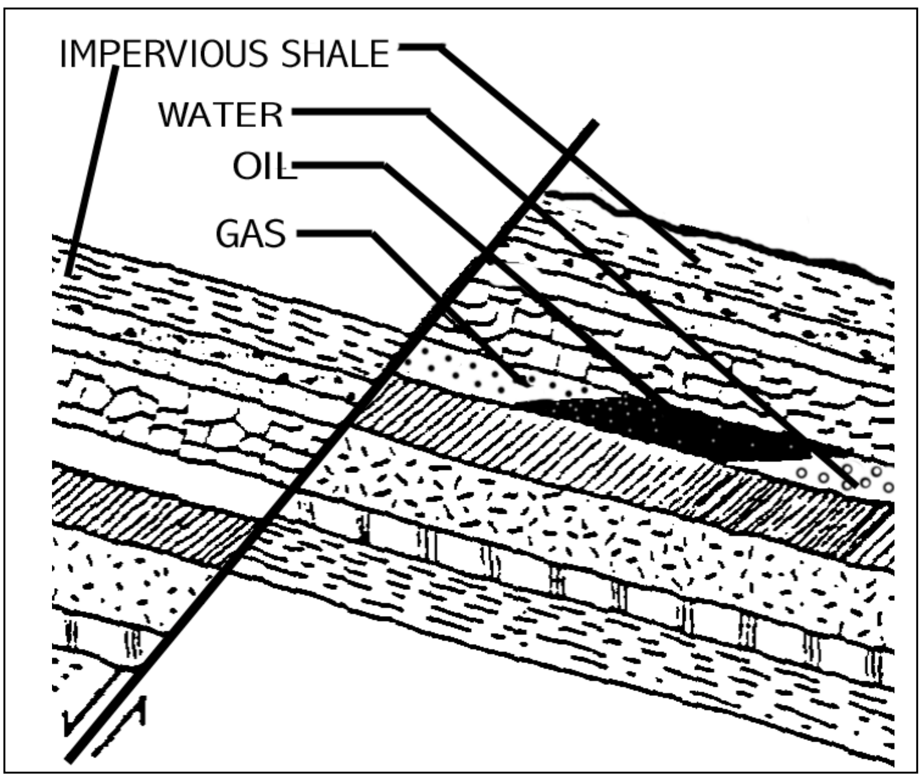


Figure 5-4: Simple Fault

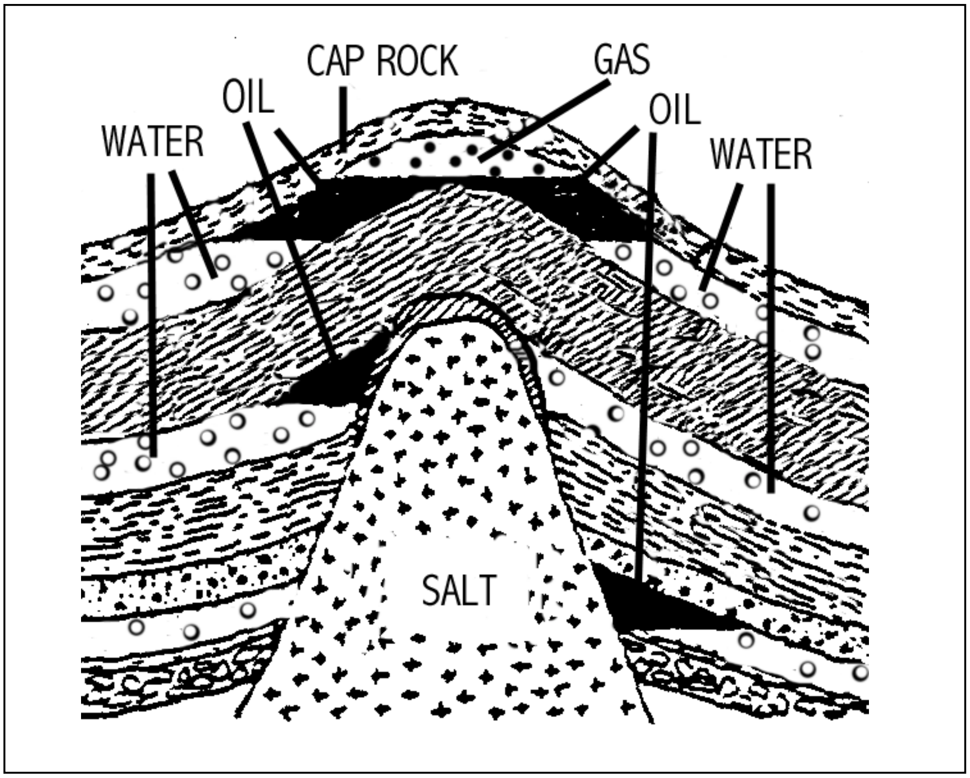
[Shifting of the earth's crust caused a porous bed to become abutted to an impermeable layer, causing a possible entrapment of hydrocarbons.]



Domes are another form of structural trap and were among the first formations to be associated with the accumulation of oil. Salt domes typify this type formation. A nonporous bed of salt, which is less dense than surrounding rocks, pushes upward and pierces or otherwise deforms weak points in the overlying formations. Where there has been a piercing of one or more formations, faults are effectively formed on each side of the salt dome. When upper strata are merely deformed or lifted, anticlines or domes become part of the overall formation. This is generalized in Figure 5-5. Some of Texas' most famous oil fields were formed around salt domes.

Figure 5-5: Piercement Salt Dome

[Illustrating the creation of faults in the lower layers and a domal formation above the salt plug]



Oil can be trapped above salt domes since an anticline is formed, or trapped alongside salt domes or in some cases beneath salt pillows or salt sills where oil is trapped beneath the salt. The presence of salt is considered very favorable for oil provinces in many regions because of its inherent instability causing domes or anticlines to form, and its high sealing potential for migrating hydrocarbons. Subsalt formations in the Gulf of Mexico provide an important area for exploration today.

Stratigraphic traps are formed by differences in the characteristics of strata at various points where oil and gas are trapped in the porous portions of the formation and are surrounded by nonporous sections. Examples of stratigraphic traps include abrupt changes in the porosity of the formation, irregular depositions of sand and shale, and changes in some of the carbonate rocks. Some of these are termed *lens-type* traps because the reservoir resembles a lens—thick in the middle but thinning on the sides. Typical stratigraphic traps are illustrated in Figures 5-6 and 5-7.

Figure 5-6: Stratigraphic Trap

[Created by grouping of porous sand formations surrounded by impermeable, or significantly less permeable, rock]

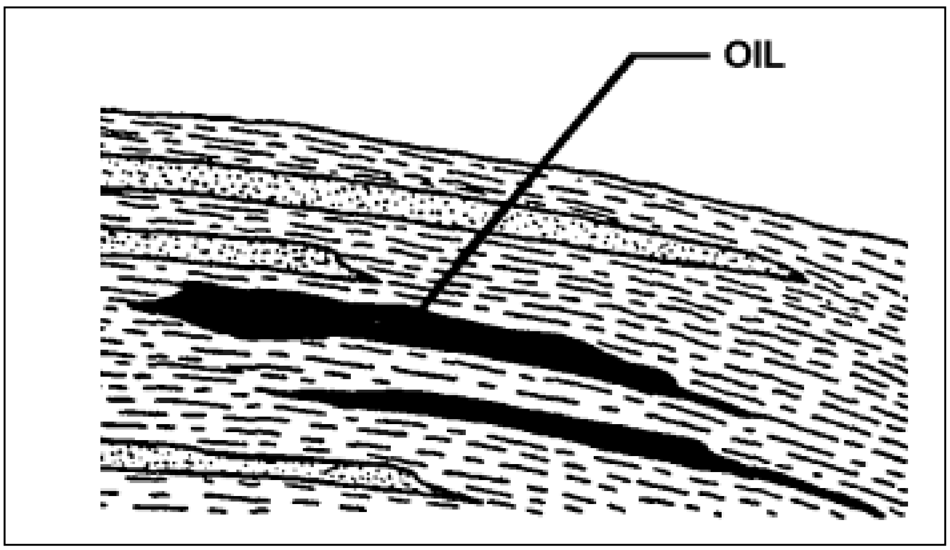
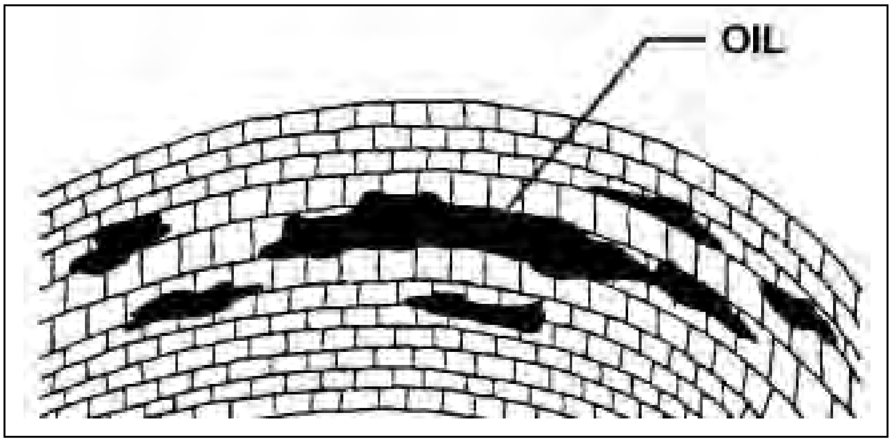
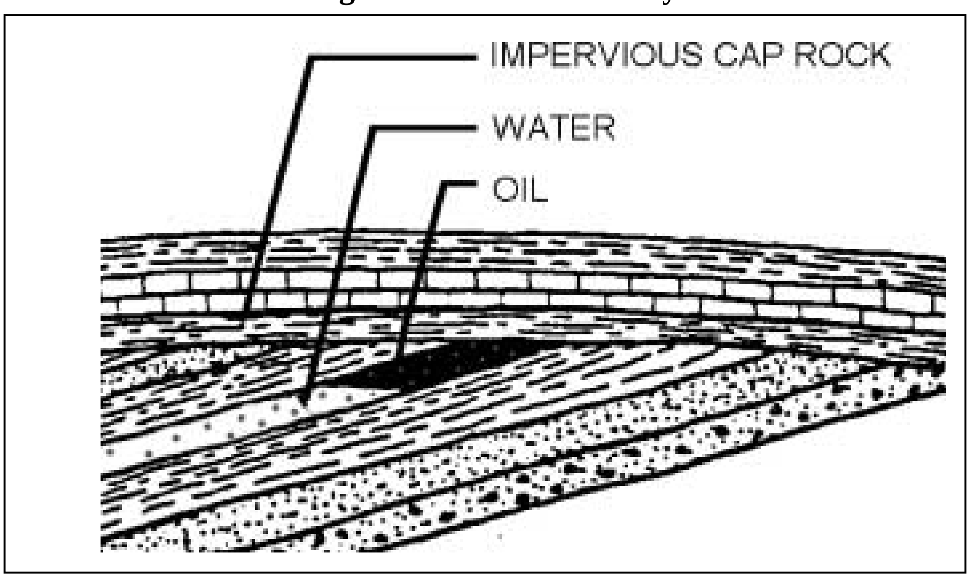


Figure 5-7: Stratigraphic Trap
[Of the type that might be formed within limestones where certain areas are of high porosity]



Some stratigraphic traps are called *truncation traps* or *unconformities* because they are associated with erosional unconformities in the strata. Erosion may have cut off portions of sedimentary strata. Subsequently, an impermeable cap rock was deposited over this cutoff (Figure 5-8). As oil and gas migrated upward through the permeable and porous strata, the movement was halted by the cap rock on top. The classic example of truncation traps is the East Texas field. Others include the West Edmond field in Oklahoma and part of the Central Kansas Uplift.

Figure 5-8: Unconformity



Many of the world's largest accumulations occur due to enhanced porosity development along unconformities or sealing or underlying porous reservoir truncated and overlain by sealing rocks. Examples include the major oil fields of Saudi Arabia such as at Ghawar, the world's largest oil field (porosity enhancement), and the largest oil field in the United States, Prudhoe Bay (truncation) along major unconformities.

Combination traps are formed as the result of two or more types of formations being combined because of folding, faulting, and other conditions in the subsurface. These often involve a stratigraphic or truncation trap being combined with a structural trap. The Oklahoma City field is an example of this type of reservoir. Rangely oil field (>1 billion barrels of recoverable oil) in Colorado is also an example of a combination stratigraphic/structural trap.

CONTINUOUS FORMATIONS

Chapter One introduced the 1990s development of gas production from tight sands and coalbeds—two types of *continuous* formations that were generally uneconomic to develop prior to the 1990s. This important new type of hydrocarbon resource has caused significant new exploration in areas previously considered unlikely for recoverable hydrocarbons, such as in the deeper centers of petroleum basins (Figure 5-9). Some studies argue that such continuous gas reserves will exceed conventional gas reserves by the year 20l0.

Substantial quantities of oil and gas are contained in *tight* formations with typically poor permeability. The formations may be vast and continuous, but the oil and gas are locked inside and do not flow naturally. To encourage development of such non-conventional sources of energy, in 1980 the U.S. government granted special tax credits for production of *tight sands* gas from wells begun prior to 1993 (as further discussed in Chapter Twenty-Six).

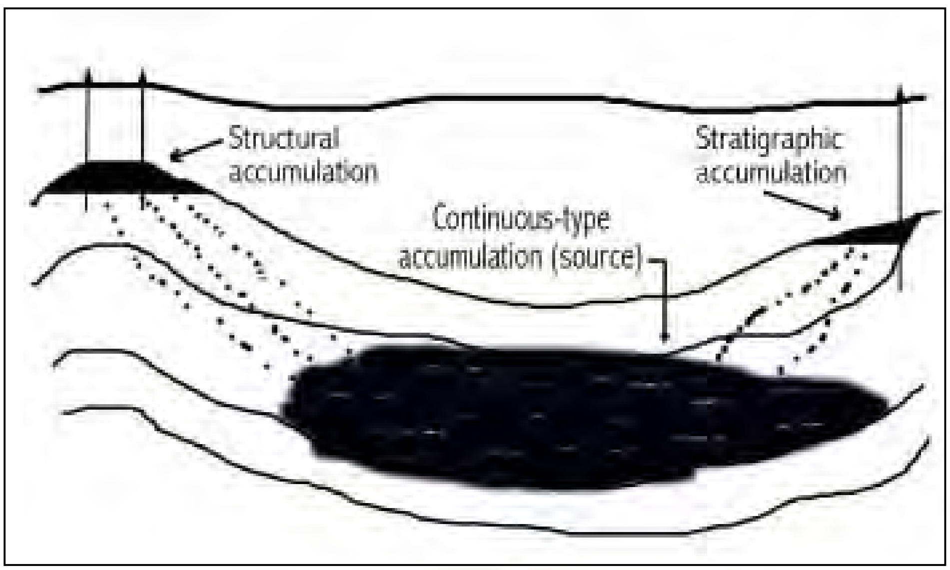
Similar tax credits were given for methane production from coalbeds. Beginning in the mid 1980s, thousands of wells were drilled to produce tight sands gas and coalbed methane in the U.S., and sparked development of similar resources in other countries. New wells no longer qualify for the credit, but the industry now has the experience and know-how to profitably develop tight sands gas and coalbed methane fields without special tax incentives.

Example of tight sands are the Codell and Niobrara formations in northeastern Colorado which produce gas and some condensate from thousands of wells drilled over the past 18 years. Such formations are opened up by fracturing the rock with fracing material temporarily pumped under high pressure into the reservoir. Flow may now be enhanced by horizontal drilling (described in Chapter Eight) whereby the well bore starts vertically but runs horizontally through the reservoir, sometimes for several hundred feet, to expose much more of the reservoir to the well than traditional drilling.

The Austin Chalk formation in southeastern Texas and Louisiana, characterized by faulting, is an example of a continuous oil producing formation that has been rejuvenated in the 1990s by horizontal drilling.

The two largest U.S. coalbed methane producing basins are the giant San Juan Basin in southern Colorado and New Mexico and the Black Warrior Basin in Alabama. Litigation has arisen as to whether the coal rights owner or the oil and gas mineral rights owner has the right to lease rights to produce coalbed methane.

Figure 5-9: Conventional vs. Continuous Accumulations



GEOLOGICAL AND GEOPHYSICAL EXPLORATION METHODS

The goal of oil and gas exploration is to locate new hydrocarbon reserves that can be produced at a profit. However, the geologist, geophysicist, or reservoir engineer cannot look directly for oil and gas. Hydrocarbons are usually found only through drilling. Nevertheless, geological and geophysical (G&G) exploration is undertaken to locate areas (on which the operator may or may not have acquired ownership of mineral rights) where it is believed that the conditions are favorable for the accumulation of oil and gas. Many different techniques to explore both the surface and the subsurface are used for this purpose. These techniques may employ geology (the study of the structure of the earth's crust), geophysics (the study of earth physics), geochemical and sometimes satellite imagery techniques. The dominant form of exploration relates to an integrated geologic—seismic approach.

SURFACE TECHNIQUES

Surface techniques include the evaluation of surface indications that oil or gas exists or that formations capable of containing oil or gas may be underground. Such techniques as searching for traces of oil or paraffin on the surface (seeps), aerial photography, topographical mapping, and geochemical surveying are commonly used.

Oil Seeps

The most reliable surface evidence of oil is a seep through which tiny amounts of petroleum migrate to the surface. References to oil seeps are present throughout much of written history. In a completely new area, onshore or offshore, the evaluation of oil seeps through soil chemistry may constitute one of the first steps in petroleum exploration. Although additional work is necessary to gain more information prior to the actual drilling of wells, some of the largest fields in the world have been discovered as a result of this very simple technique.

Aerial Photography and Satellite Surveys

Imaging radar on an airplane transmits high-frequency radio waves that are bounced off the surface and returned to the radar. Although the return echoes give only a low-resolution image, geologists find the information useful.

Aerial photography and satellite imaging radar enable geologists to obtain information about unexplored areas covering many thousands of square miles. From these data geologists can select a specific site or sites for more intensive study.

Aerial photography is expensive and often produces pictures of variable quality. Therefore, scientists now use data generated by Landsat satellites launched by the United States government for mapping and crop forecasting. Landsat 4 uses infrared bands that allow geologists to locate various deposits, such as clays, that are often associated with mineral deposits. When the images received by Landsat are enhanced by computer, one can identify land characteristics of areas as small as 100 feet in diameter. Of course, traditional exploration data are still needed to identify more specifically the likely locations of commercial deposits of minerals. However, many petroleum companies believe that Landsat's most important value lies in the elimination of areas unlikely to hold mineral deposits.

The U.S. government sells data from Landsat; the cost per square mile surveyed is much lower than the cost per square mile of aerial photography.

SUBSURFACE TECHNIQUES

The objective of subsurface exploration techniques is to provide a reasonable interpretation of the distribution of source, seal, and reservoir rocks in order to identify a trap.

Subsurface Mapping

Subsurface mapping, utilizing seismic surveys (discussed later in this chapter) and well data, is widely used today in oil and gas exploration and development. The advantage of newer seismic methods is a way of viewing, albeit with a somewhat fuzzy focus, the actual properties of the rock rather than a hypothetical interpretation. Several types of subsurface maps or multi-dimensional models may be created with this seismic data, each providing different information about the subsurface.

Structural Surface Maps

Structural surface maps depict the subsurface *topography* of the potential reservoir in the same way that topographic maps show contours of the earth's surface. Structural maps may be developed through a variety of methods, but the use of well logs and seismography (discussed later in this chapter) is most important. For conventional hydrocarbon accumulations, the locations of subsurface highs define the areas of greatest potential for hydrocarbon accumulations.

Cross-section Mapping

Cross-section mapping is also extremely important in oil and gas exploration, especially in areas with complicated structure and stratigraphy. In the past, cross-sections were generally developed on the basis of information obtained through well logs. More recently, new geophysical techniques and sophisticated computer simulations have enabled the compilation of cross sections without the necessity of first drilling numerous wells and are integrated into software packages that permit integration of seismic, well, and outcrop data.

Isopach Maps

Isopach maps show variations in the thickness of a particular sedimentary bed and can indicate the interval or spacing between sedimentary beds. Maps of this type are especially useful in the developmental stages.

In combination, these maps add much to the knowledge of the subsurface. Important as they are, however, their significance should not be overvalued since only actual drilling and testing will determine the presence or absence of *commercial accumulations* of hydrocarbons that can be profitably produced.

Subsurface Geophysical Measurements

Geophysics involves measurement of forces, or changes of forces, inherent in the earth itself and the measurement of energy forces induced by geophysical crews into the earth's crust using either dynamite (less common today) or large vibration generating machines ("vibroseis") which has less environmental impact. These seismic surveys are the predominant means today of identifying potential reservoirs prior to drilling. Offshore seismic records are acquired trailing large arrays of instruments behind ships. A device generates energy that passes through the water column into the subsurface and energy is reflected back to a series of recording devices reflecting properties of the rocks. Measurement of natural forces employs gravimetric and magnetic surveys. Measurement of human-generated forces primarily involves seismic surveys. Surveys of all these types can be either regional in nature or conducted within an individual borehole.

Gravimetric Surveys

The gravity meter measures exceedingly small variations in the gravitational pull of the earth. Because different types of rocks have different densities, they generate different gravitational forces. Larger masses of dense rocks exert a heavier gravitational pull. Where the denser formations are closer to the surface, the gravitational pull is greater. For example, in the case of a cap rock overlying an anticline, the gravitational pull will be greater over the top of the structure than it will be *off the structure*.

Gravimetric surveys are relatively inexpensive and are frequently used for broad reconnaissance-type surveys. If the results indicate potentially favorable structures, the gravimetric study will be followed by more detailed surveys, often including seismic work. Correlation and comparison of gravity measurements at multiple locations will yield useful knowledge about the subsurface.

Magnetic Surveys

Just as there are differences in the gravitational pull at different locations on the earth's surface, there are also deviations from the normal pattern of the magnetic fields. These differences arise because of granite concentrations, heavy intrusions of igneous rocks, and structures containing high magnetic concentrations. Magnetic surveys measure these differences. It is possible that these types of rocks may trap petroleum. However, if such formations appear to be fairly close to the surface, the results of the survey may indicate an area to avoid in drilling operations. Today, most magnetic surveys are conducted from aircraft and cover hundreds of square miles per day as part of general reconnaissance work.

Seismic Surveys

The word *seismic* means *of, or having to do with, an earthquake or earth vibration*. In the oil industry, the term relates specifically to oil and gas exploration by measurement of man-made sound waves that are reflected from subsurface formations. The quality of seismic results can be quite variable between areas, making a confident interpretation somewhat difficult.

Many years ago those sound waves were created by the detonation of an explosive charge (dynamite) at the earth's surface. Today, these waves are often initiated by vibrating a heavy, specially designed seismic truck or vehicle. This method, *vibroseis*, does not possess the inherent dangers of explosive charges and can even be used along roadways or city streets without producing a significant hazard. Similarly, *air blasts* are frequently used to generate the sound waves.

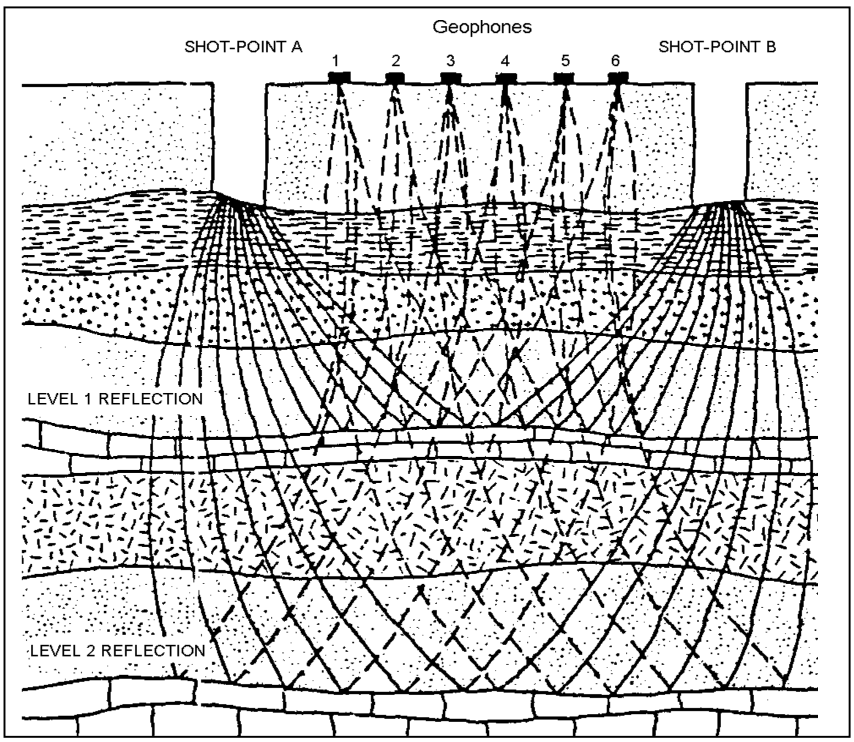
No matter what source of energy is used, the sound waves that are created travel downward through the earth's crust. Upon striking a hard or dense layer, a portion of the pressure wave is reflected back to the surface. The reflected seismic waves are detected at the surface by devices called *geophones*. These reflections are then amplified many times and recorded on a moving strip of recording tape, forming a *seismic record*.

Commonly several *shot points* are used, and for each detonation several geophones are placed in a predetermined pattern on land or trailed behind ships in specific patterns offshore. Since the seismic waves travel at a known rate of speed, measurement of the time taken for them to travel can reveal the distance traveled. The recorder will pick up three types of signals. The first signal marks the exact time of the detonation. The next signal is a refracted wave that has gone through the thin surface layer and traveled along the first hard bed and then back up to the geophones. The last signal gives reflections from the various horizons.

Knowledge of the travel time, velocity, and distance between the shot point and the geophone enables the geophysicist, using the results of several patterns, to plot the contours of the subsurface strata and indicate anticlines, faults, and other formations that may have the potential for containing oil and gas. Properties of the formation itself are commonly interpreted from higher resolution seismic data, for example, determinations of relatively more porous horizons, perhaps the presence of hydrocarbons within a rock interval, etc.

Processing and analysis of seismic data today almost exclusively are carried out through the use of sophisticated computer programs. For example, cross sections representing a graphic portrayal of a vertical slice of the earth's crust along a given line can now be developed and used to plan the exact location of wells. Additionally, modern technology uses radio telemetry devices instead of long strings of electrical cables between the remote units and the recording truck. These new devices permit detailed exploration work in areas that were previously inaccessible with conventional methods. Figure 5-10 demonstrates the sound wave reflection process.

Figure 5-10: Seismic Surveys



There have been numerous advances in the use of seismic data by geophysicists. Tremendous amounts of research are continually conducted in an attempt to develop a method to detect the presence of oil and gas without having to conduct exploratory drilling, an expensive process. One method of interpreting seismic data, termed *bright spot*, focuses on blank or bright spots on seismic cross sections. Not all of the bright spots indicate formations containing hydrocarbons, and even if hydrocarbons are present, they may exist in some form other than oil or gas. The method has been most successful in detecting shallow formations containing gas offshore in the Gulf of Mexico.

Three-Dimensional (3D) Seismic. Generally, seismic data provides a picture of subsurface beds using acoustic energy. Conventional two-dimensional (2D) seismic data are collected by stringing geophones in a line along the earth's surface or trailed behind a ship. The 2D method provides a limited, two-dimensional cross-sectional view of subsurface beds and structures illustrated in Figure 5-11, compared to the three-dimensional color images made possible by 3D seismic surveys and the improved power and performance of computer workstations. Figure 5-12 illustrates the 3D view.

Figure 5-11: Imaged Data from a Two-Dimensional Seismic Survey

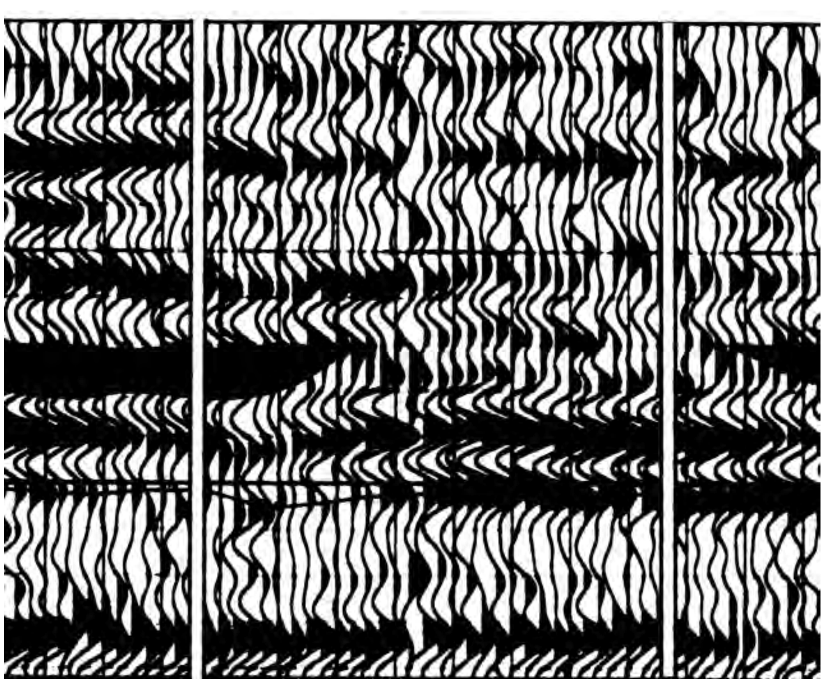
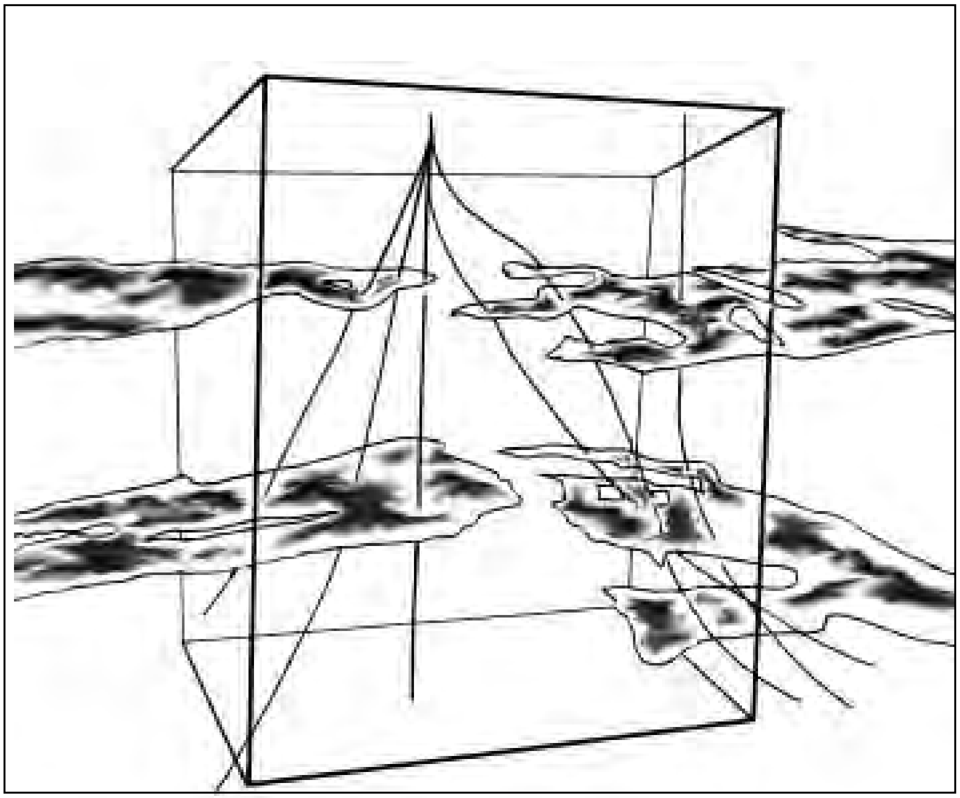


Figure 5-12: 3D Image from a Three-Dimensional Seismic Survey (showing four productive formations penetrated by directional drilling)



3D seismic data are collected using geophones in a closely spaced grid rather than a single line. The 3D method provides three-dimensional views of the formations and gives dramatically higher resolution than conventional 2D because it captures 10,000 times more data. Importantly, the implementation of 3D seismic has confirmed to the industry that subsurface structure and stratigraphy are generally more complex than previously believed. This new perspective has revived the industry's interest in old fields that were thought to have been exhausted. In addition, the increased resolution of the subsurface serves to significantly reduce the risk of drilling dry holes. An important exploration application of this technology is the Horse Shoe Atoll Reef trend in West Texas, where small pinnacle reefs can now be resolved by 3D seismic. In some cases, 3D seismic can also distinguish the type of fluid in a reservoir. This new technology is called *amplitude variation with offset* (or AVO).

Four-Dimensional (4D) seismic. This refers to shooting 3D seismic over time, the fourth dimension. 4D seismic may be useful in large reservoirs to evaluate whether new wells or new recovery programs can economically improve production. 4D programs are commonly used today to monitor waterflood fronts and oil migration within reservoirs.

Offshore Exploration. Offshore exploration uses most of the same techniques as onshore exploration, but with some modifications, especially when seismic exploration is involved. For environmental and other reasons, explosive charges cannot be detonated offshore. However, sonic waves must be generated so that their reflections can be metered and used to plot the structures beneath the ocean floor. Two principal substitutes for explosives have been developed. One substitute is the controlled detonation of a mixture of propane and oxygen within a rubber sleeve. The other is a powerful oscillator that continuously changes frequencies. The reflections from the formations are detected by listening devices that are towed behind an ocean-going vessel. Although the technology differs from onshore seismic work, the results are the same. Through computer analysis, the recordings of the seismic reflections allow geophysicists to plot subsurface structures, thus adding to the geological and geophysical knowledge of the formations beneath the ocean floor.

Offshore exploration is also complicated by the fact that many permits must be obtained from governmental agencies having jurisdiction over the area to be explored before any type of exploration may be conducted. Permits are necessary for reconnaissance-type surveys but are far more complicated if detailed surveys are to be used.

Geophysical (Seismic) Exploration Crews. A typical geophysical exploration party may involve 15 or more persons, depending on the type and location of the survey to be conducted. A party chief heads the crew, with persons having other specialties reporting to him. For example, there will be one or more geophysicists, a *permit man*, a surveyor, and observers, each having several persons within their individual subcrews. The costs of maintaining crews moving from project to project are obviously large. In some areas the cost of a crew may be as low as $1,000 a day, but in other areas, the cost may exceed $5,000 per day. As would be expected, offshore work is the most expensive on a per-day basis. However, offshore crew costs may, in the final analysis, be less expensive because an offshore crew can explore much more acreage per day than can its counterparts on shore.

Computer-Aided Exploration. Since the mid-1980s, the availability of low-cost yet significant computing power has changed the exploration and production) interpretive process with much greater efficiency in finding hydrocarbons. With computers, large amounts of well data can be stored and manipulated with greater accuracy and consistency than ever before. In addition, computer workstations can now manage seismic, geological, and engineering data for a given prospect or area. Interpretations of the subsurface now require a multidisciplinary approach that integrates geological, geophysical, and engineering professions. Maps and cross sections can now be managed and manipulated using advanced computer techniques that involve specialized statistical approaches. Advances in seismic such as 4D brings these disciplines into ever greater contact. The reservoir geologist and reservoir engineer can monitor in real time the effectiveness of their efforts to increase oil recovery by using 4D seismic and, in some cases, sophisticated new satellite imagery.

Chapter Six

ACCOUNTING FOR EXPLORATION COSTS

In this chapter principles and procedures used in accounting for exploration costs will be examined. General financial accounting principles are presented first; details of control systems, recording procedures, and special problems related to specific types of costs are then discussed. It is assumed in the discussion that the successful efforts method is being used. Under successful efforts accounting, all exploration costs except costs of exploratory wells are generally charged to expense as incurred. All exploration costs are capitalized by companies using the full cost method. However, accounting systems and procedures used by both types of companies are almost identical.

GENERAL TREATMENT OF EXPLORATION COSTS

Under the successful efforts method advocated by the FASB and adopted by the SEC in Reg. S-X Rule 4-10, *all* exploration costs are expensed when incurred, except those costs applicable to exploratory wells (including exploratory-type stratigraphic test wells) that result in the discovery of proved reserves. Some G&G costs are not in substance G&G exploration costs but rather lease acquisition costs or field development costs. Accordingly, such G&G costs generally are not expensed as incurred. Under the full cost method, all exploration costs are capitalized as part of the oil and gas assets in the cost center.

G&G costs and the cost of test-well contributions are discussed in this chapter. The costs of carrying and retaining nonproductive properties are discussed in Chapter Seven. Because drilling activities differ substantially from other types of exploration and because drilling costs may be accounted for differently, they are discussed in detail in Chapter Eight. However, the requirements of Oi5 in accounting for exploratory drilling costs by companies using the successful efforts method are summarized in the following paragraph.

Costs of drilling exploratory wells, including exploratory-type stratigraphic test wells, are initially capitalized as a work-in-progress deferred charge until the outcome of the well is known, at which time the costs are appropriately charged to expense or are capitalized. Costs of wells that result in finding proved reserves are capitalized as part of the cost of wells and related facilities. When exploratory wells are unsuccessful in finding proved reserves, their costs are charged to exploration expense. Special rules are used to determine the proper treatment of costs of exploratory wells in progress or of wells on which the drilling has been completed but for which it cannot be immediately determined whether proved reserves have been found.

The following example illustrates the financial accounting treatment of exploration costs. Assume that a broad exploratory study is undertaken at a cost of $150,000 on a project. As a result of the reconnaissance survey, two areas of interest, designated as Area *A* and Area *B*, are defined. Before attempting to acquire any acreage, the company undertakes detailed surveys on the two areas. Costs of the detailed surveys were $20,000 for Area *A* and $10,000 for Area *B*. The detailed exploration revealed little likelihood of the existence of oil or gas in Area *B*, and the area was abandoned. However, the results for Area *A* were positive, and two leases, one containing 320 acres and one containing 480 acres, were acquired.

Companies using the successful efforts method of accounting specified in Oi5 would charge all of these costs to current expense in entries that ultimately result in the following:

801 Exploration Expense (Geological and Geophysical)	180,000	
101 Cash		180,000

Detailed procedures, journal entries, and accounting records for the costs of geological and geophysical exploration are discussed in subsequent pages.

GENERAL TAX TREATMENT OF EXPLORATION COSTS

Exploration costs are defined differently for federal income tax purposes than for financial accounting purposes. These costs are also treated differently. For federal income tax purposes, exploration costs do not include carrying costs, test-well contributions, drilling of exploratory wells, and drilling of exploratory-type stratigraphic test wells.

The basic philosophy of the Internal Revenue Service is that G&G expenditures are essentially capital in nature and are not to be considered as expenditures that are *per se* immediately deductible. For tax purposes, geological and geophysical expenditures that are part of broad reconnaissance-type surveys undertaken to find smaller areas of interest must be allocated equally to each area of interest found. If no area of interest is found, the costs are considered as an expense of the year in which it is determined that there is no area of interest. The reconnaissance survey costs allocated to an area of interest, along with the cost of any detailed survey on that area, are capitalized to any leases acquired in the area. If more than one lease is acquired in an area of interest, the deferred charges are allocated among the leases in proportion to the acreage in each lease. The costs applicable to projects and to areas of interest include an allocable portion of overhead, apportioned on some logical and consistent basis. These capitalized exploration costs, together with lease acquisition costs (for example, bonuses), become the leasehold cost for federal income tax purposes as further illustrated in Chapter Twenty-Six.

RECORD-KEEPING AND CONTROL PROCEDURES

The accounting system must provide information to be used in the E&P company's financial statements. But it must also furnish data to meet many other needs. In developing procedures and records to account for exploration costs, the following needs are typical of those that must be kept in mind.

1. Exploration activities center around specific projects undertaken to locate structures favorable to the accumulation of hydrocarbons. Management must know the costs of each project in order to determine its ultimate profitability.
2. Development of the exploratory budget is dependent on the accounting system for information.
3. Cost control depends on an adequate accounting and reporting system.
4. Regulatory agencies, such as the Department of Energy, impose specific requirements necessitating appropriate classification and accumulation of data.
5. The treatment of various costs for federal income tax purposes differs markedly from that for financial reporting purposes, requiring additional detailed records.
6. Frequently, detailed historical cost records are required for legal and contractual purposes.

Thus the accounting and record-keeping procedures must be designed to serve a multitude of persons and users. No single system will serve the needs of all companies; however, the procedures discussed in the following pages are typical.

THE AUTHORIZATION SYSTEM

Most exploration is undertaken on a *project* basis, with work on a project sometimes extending over a considerable period of time, frequently several years. Approvals are usually required because of the large expenditures incurred, the length of time involved, and the need to maintain tight control over cash expenditures. Depending upon company policy, approvals for specific expenditures in excess of some specified amount are necessary. Endorsements and approvals are usually required from one or more individuals having functional responsibilities. The procedure for giving written approval for large expenditures may require an a*uthorization for expenditure* (AFE), containing a description of the project, a listing of proposed expenditures, and spaces for appropriate approvals.

Many companies in the industry reserve the term *AFE* for those expenditures involving the drilling of exploratory or developmental wells. They use other procedures and forms, such as *project approvals,* for other activities. The procedures involved are basically the same; therefore, no attempt is made in this chapter to distinguish between the different types of authorization. In any case, an expenditure of a major amount requires approval of one or more individuals in any organization and, for a joint venture, approval by all working interest owners. Accordingly, the term AFE is used in this book for any planned expenditures where approval is required.

For example, assume that Our Oil Company is contemplating exploration in an area and that the estimated amount of direct expenditures involved is $50,000, requiring an approved AFE before work can commence. The form illustrated in Figure 6-1 has been initiated by a district geologist.

The detailed items specified on the exploration AFE correspond to the subsidiary accounts for exploration expense, discussed later in this chapter. The amount for overhead is simply an estimate (in this case, 20 percent of direct costs) and does not indicate expected cash expenditures on the project.

Approval of the AFE does not require an entry in the formal accounting records; its purpose is for internal control of expenditures. Even though exploration budgets are somewhat flexible, the AFE encumbers some portion of the budget. Costs are accumulated for each project to be compared with the amounts authorized. The columns entitled Actual Cost and Variance provide the means for making comparisons between estimated and actual costs when the project is completed, as shown in Figure 6-1.

Figure 6-1: Completed AFE

AUTHORIZATION FOR EXPENDITURE – EXPLORATION

REQUEST FOR AUTHORITY — AFE NO. 99008
J. Smith, Exploration Dept. — DATE 05/12/00

LOCATION: T7N, R21E, Haskell Co., Oklahoma

PURPOSE: To conduct exploration activities for possible leasing and subsequent drilling and development in area.

ITEM	ESTIMATED COST	ACTUAL COST	VARIANCE
01 – G&G Contract	$40,000	$38,000	$2,000
02 – G&G Services – Other	0	0	0
03 – Field Party Salaries	7,000	7,400	(400)
04 – Field Party Supplies	0	0	0
05 – Field Party – Other	1,000	1,200	(200)
06 – Support Facilities	0	0	0
07 – Shooting Rights and Damages	2,000	2,300	(300)
08 – Mapping Expense	0	0	200
09 – Equipment Rental	0	0	0200
10 – Other Geological and Geophysical Costs	0	0	0
11 – Purchased Geological and Geophysical Data	0	0	0
TOTAL DIRECT	$50,000	$48,900	$1,100
12 – OVERHEAD	10,000	9,780	220
TOTAL	$60,000	$58,680	$1,320

APPROVALS: (signed M. Jones) 05/20/00

ACCOUNTS AND SUBACCOUNTS FOR EXPLORATION EXPENSE

The accounting system must ensure the proper recording of transactions. It must also accumulate information that will enhance internal control, facilitate analyses of operations for management, and provide data for the correct filing of federal, state, and local tax returns and regulatory reports. Thus the elements of each transaction typically are not classified merely by the general ledger accounts involved but by various other categories. In order to facilitate the proper classification of data, it is customary for oil and gas producing companies to use a complex coding system in their recording procedures.

The exact details of classifying and recording data in transactions depend on the desires and needs of management, on the organizational structure of the company, and on the nature and scope of operations. In this chapter a typical *coding system* used to facilitate classification of data will be illustrated. Because such a system is cumbersome to demonstrate, the system is not used consistently through the remainder of this book.

Under Oi5, a company using the successful efforts method must charge all exploration costs to expense as incurred except for costs of successful exploratory wells, wells in progress, and certain G&G costs incurred to acquire a property interest.

The general ledger accounts used by Our Oil Company, listed below, are used to record exploration expenses. They correspond generally to the categories described in Oi5.108.

801 Geological and Geophysical Costs
802 Carrying and Retaining Undeveloped Properties
803 Test-Well Contributions
804 Unsuccessful Exploratory Wells
805 Unsuccessful Exploratory Stratigraphic Wells

The various subaccounts related to carrying and retaining undeveloped properties (Delay Rentals, *Ad Valorem* Taxes, Legal Expenses, and Record Maintenance Costs) are discussed in Chapter Seven.

Those accounts related to exploratory drilling activities (Unsuccessful Exploratory Wells and Unsuccessful Exploratory Stratigraphic Wells) are examined in Chapter Nine. The other accounts related to exploration activities are examined in this chapter.

G&G SUBACCOUNTS

Costs related directly to G&G exploration are charged by Our Oil Company to account 801, Geological and Geophysical Costs, regardless of whether the amount involved is associated with an AFE.

Subsidiary accounts are maintained to provide information for analysis and control of costs. Our Oil Company has the following detailed accounts:

801	001	Geological and Geophysical Contract Work
	002	Geological and Geophysical Services Other
	003	Field Party Salaries and Wages
	004	Field Party Supplies
	005	Other Field Party Expenses
	006	Charges for Support Facilities
	007	Shooting Rights and Damages
	008	Mapping Expenses
	009	Equipment Rental
	010	Other Geological and Geophysical Costs
	011	Purchased Geological and Geophysical Data
	012	Overhead

Obviously, the nature and degree of detail for subsidiary accounts needed and desired will vary from company to company.

Although companies using the full cost method capitalize all G&G costs, most companies will maintain subsidiary accounts similar to those above in order to control and analyze costs.

CHARGING COSTS DIRECTLY TO G&G EXPENSE

All costs associated with each AFE are identified and can be accumulated through that identification. This is accomplished in the coding of charges and credits. The costs can be immediately charged to the expense accounts in the general ledger by a company using the successful efforts method or to the asset account by a company using the full cost method or can be entered in a work-in-progress account and deferred.

To illustrate the first procedure, suppose that an invoice for $38,000 covering seismic work on AFE 99008 (which was shown in Figure 6-1) was received, vouchered, and assigned voucher number 02098. Coding for the charges included in the invoice might be as follows:

801-001-02098-99008	G&G Expense	38,000	
301-742-02098-99008	Vouchers Payable		38,000

Explanation of the account coding:

- 801 indicates that the general ledger account charged is G&G costs.
- 001 is a sub-account that shows the charges are for G&G contract work.
- 02098 specifies that the charge is from voucher number 02098, the 98th voucher number assigned in February.
- 99008 indicates that the costs are incurred on the project covered by AFE 99008, the 8th AFE approved in 1999.
- 301 is the account number for Vouchers Payable.
- 742 is the vendor number.

When vouchers are prepared for G&G costs that are not covered by an AFE, the number 00000 is assigned to the AFE code block. For example, a payment of $2,000 was made on voucher number 02099 to a geologist to analyze well abandonment records filed with the state regulatory commission for an area in which the company is not presently operating. No AFE was prepared for this job since the amount involved was below the cutoff point at which authorization was required by company policy (for example, $20,000). This expenditure would be recorded as follows:

801-002-02099-00000	G&G Expense	2,000	
301-750-02099-00000	Vouchers Payable		2,000

This entry indicates that a charge has been made to G&G expenses (G&G Services—Other), that no AFE is involved, and that the voucher number is 02099 (coding numbers and details of subsidiary records will not be used in subsequent illustrations in this book).

Periodic computer runs show the costs accumulated for each AFE. When a project is completed, a comparison is made between approved and actual costs for each subaccount. This comparison for AFE 99008 is shown in Figure 6-1. The costs related to the completed project are then removed from the active AFE file and transferred to a completed AFE file.

CHARGING COSTS TO WORK IN PROGRESS

Some companies prefer to charge costs incurred under an AFE to an asset (deferred charge) account entitled Work in Progress (or Exploration in Progress). The costs pertaining to each AFE are accumulated in one account. When the work covered by the AFE is complete, the G&G costs are charged generally to Exploration Expense and credited to the Work in Progress account. This procedure offers additional internal control in that all of the costs pertaining to an AFE are located in one general ledger account until the AFE is complete, as opposed to being spread among multiple accounts. Furthermore, as long as the amounts are included in Work in Progress, it is evident that the project is not yet complete.

If this method is followed, for statement purposes an entry must be made at the end of each period to adjust the accounts by closing all Work in Progress Exploration accounts. A successful efforts company will close the account into Exploration Expense. To illustrate this method of accumulating costs incurred under a particular AFE, assume that Our Oil Company uses this procedure. For the charges indicated on voucher number 02098 (see the previous example) the charge would have been recorded as follows:

240	Work In Progress — Geological and Geophysical Exploration	38,000	
	301 Vouchers Payable		38,000

Note that the only difference in the recording of this charge is that it is being carried in a Work in Progress account (account 240) rather than being charged directly to an expense account as in the previous example. If the project has not been completed at the end of the accounting period, an adjustment is required to close the accumulated costs into exploration expense for financial statement presentation, as has been pointed out. For example, if at the end of the accounting period $45,400 of costs have been accumulated on an exploration project but the project has not been completed, the following entry would be made:

801	Geological and Geophysical Expenses	45,400	
	240 Work In Progress — Geological and Geophysical Exploration		45,400

Since the project has not yet been completed, a successful efforts company must reverse the above entry at the beginning of the following accounting period in order to continue the project in progress.

240	Work In Progress — Geological and Geophysical Exploration	45,400	
	801 Geological and Geophysical Expenses		45,400

Additional costs under the AFE will be accumulated in the Work in Progress account in the usual manner until the project is completed.

The two preceding entries could be eliminated if the chart of accounts and the general ledger simply classified the G&G Work in Progress accounts within the Exploration Expense section (accounts 800 to 899). This practical approach is not unreasonable since G&G costs are almost always expensed as incurred under successful efforts.

To complete this example, let us assume that later this AFE has been completed and is ready to be closed. The entry to close the AFE and to record the exploration expense under the successful efforts method is as follows:

801	Geological and Geophysical Expenses	58,680	
	240 Work In Progress — Geological and Geophysical Exploration		58,680

Each of the subsidiary accounts under a Work in Progress account would also be credited.

This entry records completion of the project and the charging of all costs to expense. The analysis of estimated and actual costs can now be prepared for managerial use with a greater assurance that all charges applicable to this particular AFE have been included.

While other procedures will be used for some illustrations in this book, the use of a Work in Progress account for all AFEs will be assumed to be standard policy for Our Oil Company. As previously observed, some companies do not use AFEs for exploration projects but nevertheless do control expenditures through proper approvals and accumulate costs related to specific activities.

SPECIAL PROBLEM AREAS IN ACCOUNTING FOR EXPLORATION COSTS

Although Oi5 clearly defines exploration costs and explains how they are to be accounted for, certain problems of interpretation do arise. Some of the most common of these problems are discussed below.

EXPLORATION PERMITS (SHOOTING RIGHTS)

Exploration may be carried out either prior to or after mineral leases are acquired. In most cases, if exploration is to be conducted before a lease is obtained, an exploration permit, commonly called *shooting rights*, must be obtained from the property owner. If offshore exploration is involved, a permit that does not usually require the payment of a fee must be obtained, normally from the U.S. Department of Interior's Minerals Management Service (MMS). In either offshore or onshore activities, permission is required to conduct exploration.

Onshore exploration rights may take one of two forms. Under a *shooting rights only* contract, the rights holder is allowed to enter onto the property and conduct exploratory activities, up to but not including the drilling of an exploratory well. The costs involved with such a contract are properly classified as exploration expense under successful efforts. The entry to record exploration permits obtained under AFE 99008 (assuming the use of a Work in Progress account) would be:

240.007	Work in Progress — Shooting Rights and Damages	2,300	
	301 Vouchers Payable		2,300

In other cases the contract not only may grant shooting rights but also may contain an option for the grantee to lease all or any part of the mineral acreage covered by the contract for a specified sum, usually expressed as so much per acre. Acreage selection options are examined below.

ACREAGE SELECTION OPTIONS

An option agreement may specify the amount applicable to the shooting rights and separately state the cost of the option. In that case the cost of the exploration rights will be treated in the same manner as any other exploration cost. However, if no division of the cost is made in the contract, the entire payment should be treated as applicable to the option to acquire acreage. Accounting for option payments is discussed in greater detail in Chapter Seven, but at this point it should be noted that if none of the acreage covered by the option is leased, the entire amount of the option cost is charged to expense, both for financial accounting purposes by a company using the successful efforts method and for tax purposes. If all of the acreage is leased, all of the option cost is capitalized as cost of the mineral rights; if only part of the acreage is leased, either all or part of the cost, depending on company policy, is capitalized by a company using successful efforts accounting. A full cost company will capitalize all option costs in every case.

TEST-WELL CONTRIBUTIONS

Frequently the owner of a property will agree to contribute cash to the operator of a nearby lease to defray a portion of the drilling costs of a test well and will be entitled to receive certain specified information, such as cuttings, core samples, and logs obtained in drilling the well.

In the case of a dry-hole contribution, funds are paid to the drilling party only in the event that the well is dry or does not result in completion as a producer. Bottom-hole contributions are paid upon the drilling party's reaching the proposed depth or a specific geological formation, regardless of the outcome of the well.

For financial accounting purposes, the recipient of the test-well contribution treats the amount received as a reduction in well costs. For federal income tax purposes, the Internal Revenue Service now requires the recipient to include the amount received as income.

The payor treats both types of test-well contributions as exploration costs for financial accounting purposes. For example, a dry-hole contribution of $10,000 not covered by an AFE might be recorded as follows by Our Oil Company, which uses successful efforts accounting.

803	Test Well Contributions Dry Hole Costs	10,000	
	301 Vouchers Payable		10,000

Under full cost all test-well contributions are capitalized as part of the cost pool. The costs may be allocated to individual nearby properties or may be charged to account 261, Unallocated Exploration Costs.

For federal income tax purposes, all contributions must be capitalized and added to the cost of other acreage owned by the contributor in that area.

EXPLORATION PERFORMED IN RETURN FOR ACREAGE

An operator owning lease rights in unproved acreage may agree to contribute an interest in that acreage (either an undivided interest in the entire acreage or divided interest in a fractional share of the tract) to another company in return for the latter agreeing to carry out specified exploration work on the acreage. Accounting for this *pooling of assets* is addressed in Oi5.138(c). A successful efforts company performing the exploration will charge the costs incurred to exploration expense, while a full cost company will capitalize such costs. The company assigning the acreage will record its total acreage cost as the cost of its retained interest. Of course, proper notations of the reduction of ownership in the acreage will be made in the land department records of the assignor of the interest.

Assume that Our Oil Company holds leases on 5,000 acres in Hardin County, Texas, that were acquired at a total cost of $800,000. A contract is entered into with Outside Company, a successful efforts company, under which the latter agrees to conduct specified exploration activities. On completion of the work, regardless of whether the outcome is successful, Outside Company is to be assigned a one-fourth interest in the property. Outside Company spends a total of $360,000 for the exploration activities. Outside Company would record the exploration costs and the earning of an interest in the properties as follows:

801	Geological and Geophysical Expense	360,000	
	301 Vouchers Payable		360,000

To record the cost of work performed for an interest in Our Company's leases in Hardin County, Texas.

Outside Company assigns no cost to the leasehold interest acquired (although most companies would assign some nominal amount, such as

$1, to the property for control purposes). If this were done, in the above example $1 would be charged to Unproved Leaseholds, Account 211, and $359,999 would be charged to Geological and Geophysical Expense. Our Oil Company would make no entries in the accounting records. It would, however, record the new reduced interest in the properties in the detailed lease records.

Under a different type of arrangement, the contract may specify that the party performing the work will acquire an interest in the property *only* if the work indicates the existence of reserves. This is a *conditional pooling of assets*. However, once again, the accounting treatment required for a successful efforts company performing the work is to charge all costs to exploration expense and for the party owning the property to make no entry. The entry required by Outside Company to record the costs incurred would be the same as in the preceding example and, again, Our Oil Company would make no accounting entries.

A third type of exploration arrangement is accorded special treatment by Oi5.111. G&G studies may be conducted on a property owned by another person in exchange for an interest in the property if proved reserves are found or for reimbursement of the costs if proved reserves are not found. In such cases the G&G costs shall be accounted for as a receivable when incurred by the party performing the services, and if proved reserves are found, the G&G costs shall become the cost of the unproved property acquired.

A literal interpretation of this rule is shown by the following illustration. Our Oil Company owns a lease covering 10,000 acres. An agreement is entered into with Outside Company under which the latter agrees to conduct certain exploration activities on the property. If proved reserves are found, Outside Company is to be assigned one-sixth of the working interest in the property. If no proved reserves are found, Our Oil Company is to reimburse Outside Company for the costs incurred. Outside Company's total cost of the project is $80,000.

Outside Company would charge the costs incurred to a receivable account:

130 Accounts Receivable	80,000	
301 Vouchers Payable		80,000

If no proved reserves are found, Our Oil Company would reimburse Outside Company for the $80,000. Outside Company would record receipt of the payment as follows:

101	Cash	80,000	
	130 Accounts Receivable		80,000

On the other hand, if proved reserves are found, Outside Company would record the receipt of the mineral interest as follows:

221	Proved Leaseholds	80,000	
	130 Accounts Receivable		80,000

Our Oil Company would make no entry if proved reserves are found but would merely reduce the share of ownership in the property. If no proved reserves are found, the reimbursement of costs to Outside Company would be recorded as an exploration expense by Our Oil Company as follows:

801	Geological and Geophysical Expense	80,000	
	301 Vouchers Payable		80,000

The treatment required by Oi5.111 in this situation is somewhat inconsistent. Presumably, exploration work would have to include exploratory drilling, because it would be rare for proved reserves to be discovered by other methods. However, if drilling is undertaken in return for an interest in a mineral property, the driller is required to treat the entire amount spent for drilling as the cost of wells and related facilities. If proved reserves are found, presumably that part of costs incurred for exploration other than drilling (and reimbursable if proved reserves are not found) would be treated as mineral property costs, while the drilling costs would be treated as the costs of wells and related facilities. If the well were successful, the costs of drilling and equipping should be capitalized, if the drilling is unsuccessful, the costs, net of any salvage would be charged to expense.

PURCHASED G&G LIBRARY

Sometimes oil and gas operators will purchase a *library* of G&G data. The library may relate to a specific area of interest, basin, or trend, or it may be a library of information about many areas. Oi5 would seem to require that the costs of all purchased exploration data be charged to expense at the time the costs are incurred. Nevertheless, some successful efforts companies have argued for treating such costs as deferred charges if the information is expected to be used over a period of years and to the extent the library itself can be resold and its capitalized costs readily recovered in cash (analogous to the exception in Oi5.111). Those companies argued that if the costs can be allocated to specific areas, the related costs may be charged to expense when the information is used. If the costs cannot be identified with information relating to specific areas, the deferred costs will be amortized over their estimated useful life (perhaps two or three years) using straight-line amortization. Such treatment would rarely, if ever, be appropriate. If this method is used, care should be taken to ensure that deferred costs are truly for a saleable library and recoverable by sale of the data; if not, such costs should be expensed at the time they are incurred.

3D SEISMIC FOR PROVED PROPERTY DEVELOPMENT

If 3D (or 4D) seismic studies are used to enhance or evaluate proposed development of a proved field, the G&G costs may be capitalized as development costs. If a seismic study is also for exploration and field extension, the cost should be allocated between development costs and exploration costs.

SUPPORT FACILITIES AND OVERHEAD COSTS

Expenses related to support facilities and activities should be allocated to those activities receiving benefits. Thus costs of depreciation, taxes, repairs, and operation of equipment (such as seismic equipment, construction and grading equipment, drilling equipment, vehicles, repair shops, warehouses, supply points, camps and division, district, or field offices) may relate in whole or in part to exploration work, and that part so identified should be treated as exploration cost. Procedures for apportioning, allocating, and assigning common costs to specific activities were discussed in Chapter Three. Under successful efforts accounting, only those costs directly related to activities whose direct costs are capitalized should themselves be capitalized.

Under the full cost method, *internal* costs that are capitalized are limited to costs, including overhead, that can be directly identified with acquisition, exploration, and development activities undertaken by the reporting entity for its own account. For example, costs of operating the undeveloped properties section, the cost of exploration management, and the costs of scouts and landmen would be properly capitalized; general corporate overhead or similar costs should not be capitalized. In many cases under both full cost and successful efforts accounting, the decision as to whether costs should be capitalized is judgmental.

Chapter Seven

UNPROVED PROPERTY ACQUISITION, RETENTION, AND SURRENDER

Petroleum companies are interested in securing the rights to drill for and produce subsurface minerals. The existence of minerals is uncertain until a drilling rig has probed the earth to the depth at which exploration information has suggested that deposits of oil and gas are likely to be found. Yet the company must negotiate with owners of mineral rights in the area in which minerals are thought to exist for permission to drill wells and to produce any minerals found. Sometimes these rights may be secured by the simply purchasing the fee interest in the property, which results in outright ownership of both surface and minerals. In almost every case, the right to explore and produce is obtained by means of an *oil and gas lease* or a *mineral lease.*

This chapter focuses on leasing in the United States. Chapter Twenty-Five addresses property rights outside the U.S.

In the U.S. mineral rights may be *divided* among, and owned by, more than one person. For example, one person or group of persons may own the minerals to a depth of 4,000 feet; another person may own the minerals from 4,000 feet to 8,000 feet, etc. In this situation, the potential lessee must negotiate with the owners of the subsurface footage in which the company is interested. Even more common is a situation in which many people (frequently heirs of a decedent) own *undivided* interests (e.g., 20 percent share) in mineral rights in a property, and agreement must be reached with all the owners in order to lease the mineral rights.

If mineral rights are obtained by lease, the rights conveyed from the mineral owner to the oil company are more extensive than merely the right to drill wells and to produce oil and gas. The typical lease agreement (illustrated later in this section) grants the oil company rights to explore; drill; survey; lay pipelines; build facilities for treating, storing, and producing oil and gas; dispose of salt water; and carry on many other activities. However, the basic and most important rights are those to drill for and produce oil and gas in the United States

If different parties own the surface and minerals, the oil company, after securing from the subsurface owner the rights described above, must then make a separate agreement with the surface owner. While the surface owner cannot legally deny the lessee access to the land above the minerals leased, the surface owner is entitled to payment for damages that may occur to the surface as petroleum operations are carried out. For example, roads may be constructed and areas will be cleared for drilling operations and for machinery. As a result, the oil company converts a portion of the surface from the landowner's use, and such conversion demands adequate compensation to the landowner. If compensation cannot be agreed upon, settlement in court may arise.

Obviously the acquisition of mineral rights is a crucial activity in a petroleum company. In most petroleum companies, the land department has responsibility for acquiring and retaining unproved properties. Among the specific duties of the land department are the following:

1. Contact other oil operators, lease brokers, and land and mineral owners for the purpose of obtaining leases and minerals.
2. Advise the exploration department on leasing activities.
3. Negotiate agreements for joint operating agreements with other operators.
4. Secure pooling or unitization agreements.
5. Negotiate the drilling of promotional test wells and farmouts.
6. Check lease contracts on all newly purchased leases for proper signatures, notarization, dates, etc.
7. Maintain a complete file on all properties, including leases, royalty agreements, fee lands, and any other rights.
8. Verify that title to a lease is clear before drilling is commenced.
9. Make proper and timely payment of all lease rentals as authorized.

THE LEASE CONTRACT

Oil and gas operators normally acquire rights in unproved mineral properties through mineral leases rather than through outright purchase of fee interests. Thus, it is essential that the accountant clearly understand the nature and content of mineral lease contracts in order to understand oil and gas accounting. For this reason, the most common provisions contained in mineral lease contracts are examined in detail in this chapter.

The mineral owner in a mineral lease contract is referred to as the *lessor*, while the entity acquiring the leasehold rights is referred to as the *lessee*. While lease forms vary, the illustrative lease form in Figure 7-1 provides a good example of a typical fee lease agreement. Typical forms for federal and state mineral leases are found in Appendices 6 and 7 of this book. Regardless of the printed lease form used, the lessor and lessee may strike or add to the printed words as they arrive at a final agreement. Nearly all U.S. leases contain the following basic provisions.

LEASE BONUS

The *lease bonus* is the cash or other consideration paid to the lessor by the lessee in return for the lessor's granting the lessee rights to explore for minerals, to drill wells, and to produce any minerals found. The actual amount of the bonus is not normally recorded on the lease form; instead, wording such as *$10.00 and other valuable consideration* will appear on the lease document. The amount of lease bonus paid is the result of bargaining between the parties and is affected by such factors as proximity of the property to proved production, the number of years in the *primary term* of the lease, competition among potential lessees, the amount of royalty retained by the lessor, and many other variables. The bonus is usually computed on a per-acre basis, and may range from a few dollars per acre in wildcat locations to thousands of dollars per acre for locations near producing properties.

Leases on state and federally owned properties are normally awarded as the result of a bidding process, with leases being granted to the highest bidder. Offshore tracts often cover 5,000 or more acres, and a lease bonus of millions of dollars for a single block is not uncommon. Some offshore bidding requirements include royalty or net profit bids in addition to or in lieu of bonus bids. Figure 7-1 illustrates a typical bonus provision and also contains a description of the property.

PRIMARY TERM

The maximum period of time allowed for the lessee to commence drilling a well is referred to as the *primary term*. The lessor is anxious for the oil company to drill as quickly as possible and, thus, prefers a short primary term. The company acquiring the rights would prefer a long period of time so that the property can be evaluated, the drilling budget reviewed, other property nearby obtained, etc. In a wildcat area, a five-year to seven-year term may be negotiated. If the property is located near producing properties, the primary term may be two years or less. In recent years, a two-year or three- year primary term has become very popular.

Article 2 of the illustrative lease agreement in Figure 7-1 provides for the primary term.

DRILLING OBLIGATION

Payment of the bonus and signing of the lease keeps the contract in force for one year. If drilling does not begin within that year, the lease will terminate (regardless of the length of the primary term) unless the lessee makes a specified payment to the lessor. In succeeding years the same drilling obligation exists but can be deferred (and the lease can be retained) for successive periods of one year each by an annual payment; however, no provision is made for the extension of the lease by payment of rents beyond the primary term. The drilling obligation is illustrated in Article 5 of the lease contract.

DELAY RENTALS

The payment made to defer commencement of drilling activities for an additional year is called a *delay rental.* The amount of the delay rental is stated on a per-acre basis and is normally much smaller than the lease bonus. For example, if a lease contract called for a lease bonus of $50 per acre, the delay rental might be $1, $2, or $5 per acre depending on the prevalent practice at that time in the given geographic area. A typical rental provision is shown in Article 5 of the lease contract illustrated in Figure 7-1.

ROYALTY PROVISIONS

The lessor retains a *royalty interest* in the minerals. The interest entitles the lessor to receive free and clear of all costs a specified portion of the oil and gas produced or a specified portion of the value of such production, except for the related state severance or production taxes and any costs necessary to get the product into salable condition. Historically, the typical royalty on oil and gas properties has been one eighth, although the fractional share will probably be larger if the property is located near existing oil or gas production. The royalty share is negotiable, and in the past many landowners have been able to negotiate leases calling for a royalty interest of one-fifth or more.

To illustrate the nature of the royalty interest, suppose that Our Oil Company has acquired a mineral lease on a property in which Lessor Jones retained a one-eighth royalty interest. During the current year the lease produced 4,000 barrels of oil, which were sold for $20 per barrel. The state severance tax is ten percent of the value of the oil. The purchaser will remit to Lessor Jones the sum of $9,000 (i.e., 1/8 of $80,000 x 90%), representing the net value of Jones' one-eighth royalty share after withholding severance taxes.

Our Company, the lessee, must pay all lifting costs and other production costs on the lease. The lease contract may call for the lessor to bear a proportionate share of costs to make the product salable. An illustrative royalty provision is shown in Article 3 of the lease contract in Figure 7-1.

PRODUCTION HOLDS LEASE

Once a successful well has been drilled and commercial production is obtained, the lease remains in effect for as long as there is production without extended and indefinite interruption. If production ceases, the operator must act in good faith to resume the extraction of oil or gas within a reasonable time (specified in the lease contract). Prolonged inactivity will result in termination of the lease, in which case all mineral rights revert back to the royalty owner. These provisions are in Article 6 of the lease contract illustrated.

SHUT-IN ROYALTIES

Many lease contracts provide for *shut-in royalties*, which represent payments by the operator to the royalty owner if a successful well has been drilled and completed and is capable of producing in commercial quantities but production has not begun within a specified time. Shut-ins frequently occur on properties containing gas and may be due to the absence of a market, lack of transportation, necessity to obtain permission from a governmental unit, or other reasons. Normally, shut-in payments cannot be recovered by the operator out of future amounts accruing to the royalty owner, but in some cases the amounts paid are recoverable. Frequently the lease contract specifies that the amount of shut-in royalties will be an amount equal to the delay rentals. The last part of Article 3 in the lease contract illustrated in Figure 7-1 contains a shut-in royalty provision.

RIGHT TO ASSIGN INTEREST

The lease contract typically grants each party the right to assign, without approval of the other party, any part or all of its rights and obligations. Federal leases are an exception as shown in section twenty of the federal lease form in Appendix 6. As will be seen in subsequent chapters, the right to assign is extremely important and is included in Article 8 of the lease contract illustrated in Figure 7-1.

POOLING PROVISIONS

Most leases contain a provision that permits the operator to combine (*pool* or *unitize*) the leased property with properties owned by others. After the properties are combined, each former owner of an interest in an individual property will own an interest in the total of the pooled minerals. Normally the share of ownership in the pooled undeveloped properties is in proportion to the acreage contributed. Because of more efficient development, unitized leases have the potential for producing more oil and gas than the individual properties could produce if developed separately. Pooling or unitization almost always results in savings in operating and development costs. In some instances governmental units require pooling as a conservation measure, but in any event the lessee should insist that a pooling clause be included. A pooling provision is illustrated in Article 4 of the lease contract shown in Figure 7-1.

RIGHTS TO FREE USE OF RESOURCES FOR LEASE OPERATIONS

The operator is customarily given the right to use, without cost or royalty payment, oil and gas from the land in carrying out all operations under the lease contract. However, the royalty owner is entitled to a royalty on oil or gas used by the operator in carrying out operations on other properties in which the royalty owner has no interest. This provision is illustrated in the last sentence of Article 3 in the illustrative oil and gas lease.

MISCELLANEOUS PROVISIONS OF LEASES

The foregoing provisions are standard in an oil and gas lease. However, many other provisions are inserted into lease agreements, giving the parties special rights or imposing special obligations on them. Some of these provisions are examined below.

Option Payment

Frequently a company will initiate a preleasing agreement with a mineral owner that gives the company a stated period of time within which to elect to lease the property. The payment made by the operator for this option may include the cost of rights to explore, or a separate payment may be required for those rights. Normally the option specifies the amount of the bonus per acre to be paid if and when the lease is subsequently executed.

Fixed or Mandatory Rentals

The lease contract may provide for rental payments that cannot be avoided even though the property is abandoned or drilling has begun. In effect these payments are deferred bonuses paid on an installment basis.

Offset Clause

A commonly found provision called an *offset clause* requires an operator to drill such offset wells on the property covered by the lease as a prudent operator would drill under similar circumstances. The offset clause comes into play when a successful well is drilled on adjacent land within a specified distance of the property covered by the lease contract. The last sentence of Article 6 of the lease contract contains a 150-foot offset provision.

Compensatory Royalties

Payments known as *compensatory royalties* are made by petroleum companies to royalty owners as compensation for the latter's loss of income during periods when the company has not fulfilled its obligation to drill. Examples of situations leading to compensatory royalty payments include failure to drill an offset well or failure to follow an agreed-upon plan for development of the property.

Guaranteed or Minimum Royalties

If leases are acquired on property having a high probability of being productive, the mineral owner may be able to negotiate a provision in the lease requiring the lessee to guarantee the mineral owner a specified *minimum royalty* payment each month or each year. If the royalty owner's share of net proceeds from production is less than the specified amount, the lessee must pay the difference. Guaranteed payments may be nonrecoverable or recoverable out of future royalties accruing to the royalty owner. This provision is typically found in federal leases only but may be negotiated in *fee leases*, i.e., leases of private lands as opposed to public or government-owned lands.

Right to Take in Kind

In instances when the lessor owns a significant amount of minerals and/or is involved in activities that might require consumption of a large quantity of oil or gas (manufacturing, farming, etc.), the lessor may reserve the right to take its *royalty in kind.* In other words, in lieu of accepting value for the production sold from the lease by the lessee, the lessor takes its royalty share of actual production and secures a market for its own account, or transports the product to its facility that consumes energy. This practice requires additional metering or volume monitoring by the operator of the lease.

Call on Production

In instances when the lessor is in the business of refining or purchasing oil or marketing gas, an *option to purchase* or a *call on production* may be negotiated in the lease contract. This provision guarantees the lessor the first opportunity to purchase production for terms equivalent to current market terms. This provision is often used by lessors that are integrated oil and gas companies.

Figure 7-1: Illustrative Oil and Gas Lease

OIL, GAS AND MINERAL LEASE

THIS AGREEMENT made this________day of_____________20__, between____________________________Lessor (whether one or more) whose address is____ and____Lessee.

WITNESSETH:

1. Lessor, in consideration of_________________Dollars ($______), in hand paid, of the royalties herein provided, and of the agreement of Lessee herein contained, hereby grants, leases, and lets exclusively unto Lessee for the purpose of investigating, exploring, prospecting, drilling, and mining for and producing oil, gas and all other minerals, laying pipe lines, building roads, tanks, power stations, telephone lines, and other structures thereon to produce, save, take care of, treat, transport, and own said products, and housing its employees, the following described land in __________ County, to wit:

This lease also covers and includes all land owned or claimed by Lessor adjacent or contiguous to the land particularly described above, whether the same be in said section or sections, grant or grants, or in adjacent sections or grants, although not included within the boundaries of the land particularly described above. For the purpose of calculating the rental payments hereinafter provided for, said land is estimated to comprise_____acres, whether it actually comprises more or less.

2. Subject to the other provisions herein contained, this lease shall be for a term of_____years from this date (called *primary term*) and as long thereafter as oil, gas, or other mineral is produced from said land or lands with which said land is pooled hereunder.

Figure 7-1: Illustrative Oil and Gas Lease (continued)

3. The royalties to be paid by Lessee are (a) on oil, one-eighth (1/8) of that produced and saved from said land, the same to be delivered at the wells or to the credit of Lessor into the pipeline to which the wells may be connected. Lessee may from time to time purchase any royalty oil in its possession, paying the market price prevailing for the field where produced on the date of purchase, in either case such interest to bear its proportion of any expense of treating unmerchantable oil to render it merchantable as crude; (b) on gas, one-eighth (1/8) of the market value at the well of the gas used by Lessee in operations not connected with the land leased or any pooled unit containing all or a part of said land; the royalty on gas sold by Lessee to be one-eighth (1/8) of the amount realized at the well from such sales; (c) one-eighth (1/8) of the market value at the mouth of the well of gas used by Lessee in manufacturing gasoline or other by-products, except that in computing such value, there shall be excluded all gas components thereof used in lease or unit operations; and (d) on all other minerals mined and marketed, one-tenth (1/10) either in kind or value at the well or mine, at Lessee's election, except that on sulphur mined and marketed, the royalty shall be fifty (50) cents per long ton. In the event that any well on the land or on property pooled therewith (or with any part thereof) is capable of producing oil or gas or gaseous substances in paying quantities but such minerals are not being produced, then Lessee's rights may be maintained, in the absence of production or drilling operations, by commencing or resuming rental payments (herein sometimes referred to as shut-in gas payments) as hereinafter provided in paragraph 6. Should conditions occur or exist at the end of or after the primary term or within sixty (60) days prior to the expiration thereof, Lessee's rights may be extended beyond and after the primary term by the commencement, resumption, or continuance of such payments at the rate and in the manner herein provided for rental payments during the primary term, and each anniversary date thereof shall be considered as a fixed rental paying date, and if such payments are made, it will be considered that oil or gas or gaseous

Figure 7-1: Illustrative Oil and Gas Lease (continued)

substance is being produced within the meaning of paragraph 2 hereof. Lessee shall have free use of oil, gas, coal, wood, and water from said land, except water from Lessor's wells, for all operations hereunder, and royalty on oil, gas, and coal shall be computed after deducting any so used.

4. Lessee, at its option, is hereby given the right and power to pool or combine the acreage covered by this lease or any portion thereof with other land, lease, or leases in the immediate vicinity thereof, when in Lessee's judgment it is necessary or advisable to do so in order to properly develop and operate said premises in compliance with any lawful spacing rules that may be prescribed for the field in which this lease is situated by any duly authorized authority, or when to do so would, in the judgment of Lessee, promote the conservation of the oil and gas in and under and that may be produced from said premises. Lessee shall execute in writing an instrument identifying and describing the pooled acreage. The entire acreage so pooled into a tract or unit shall be treated, for all purposes except the payment of royalties on production from the pooled unit, as if it were included in this lease. If production is found on the pooled acreage, it shall be treated as if production is had from this lease, whether the well or wells be located on the premises covered by this lease or not. In lieu of the royalties elsewhere herein specified, Lessor shall receive on production from a unit so pooled only such portion of the royalty stipulated herein as the amount of his acreage placed in the unit or his royalty interest therein on an acreage basis bears to the total acreage so pooled in the particular unit involved.

5. If operations for drilling are not commenced on said land or on acreage pooled therewith as above provided on or before one year from this date, the lease shall then terminate as to both parties, unless on or before such anniversary date Lessee shall pay or tender to Lessor or to the credit of Lessor in __________ Bank at ___________, (which bank and its successors are Lessor's agent and shall continue as the depository for all rentals payable hereunder regardless of changes in ownership of said land

Figure 7-1: Illustrative Oil and Gas Lease (continued)

or the rentals) the sum of ___________ Dollars ($______), (herein called rental), which shall cover the privilege of deferring commencement of drilling operations for a period of twelve (12) months. In like manner, and upon like payment or tenders annually the commencement of drilling operations may be further deferred for successive periods of twelve (12) months each during the primary term. The payment or tender of rental may be made by the check or draft of Lessee mailed or delivered to Lessor or to said bank on or before such date of payment. If such bank (or any successor bank) should fail, liquidate, or be succeeded by another bank or for any reason fail or refuse to accept rental, Lessee shall not be held in default for failure to make such payment or tender of rental until thirty (30) days after Lessor shall deliver to Lessee a proper recordable instrument, naming another bank as agent to receive such payments or tenders. The cash down payment is consideration for this lease according to its terms and shall not be allocated as mere rental for a period. Lessee may at any time or times execute and deliver to Lessor or to the depository above named or place of record a release or releases covering any portion or portions of the above described premises and thereby surrender this lease as to such portion or portions and be relieved of all obligations as to the acreage surrendered, and thereafter the rentals payable hereunder shall be reduced in the proportion that the acreage covered hereby is reduced by said release or releases.

6. If prior to discovery of oil, gas, or other mineral on said land or on acreage pooled therewith, Lessee should drill a dry hole or holes thereon, or if after discovery of oil, gas, or other mineral, the production thereof should cease from any cause, this lease shall not terminate if Lessee commences additional drilling or reworking operations within sixty (60) days thereafter or if it be within the primary term, commences or resumes the payment or tender of rentals, or commences operations for drilling or reworking on or before the rental paying date next ensuing after the expiration of 60 days from date of completion of dry hole or cessation of production. If at any time subsequent to sixty (60) days prior to the

Figure 7-1: Illustrative Oil and Gas Lease (continued)

beginning of the last year of the primary term and prior to the discovery of oil, gas, or other mineral on said land or on acreage pooled therewith, Lessee should drill a dry hole thereon, no rental payment or operations are necessary in order to keep the lease in force during the remainder of the primary term. If at the expiration of the primary term, oil, gas, or other mineral is not being produced on said land or on acreage pooled therewith, but Lessee is then engaged in drilling or reworking operations thereon or shall have completed a dry hole thereon within sixty (60) days prior to the end of the primary term, the lease shall remain in force so long as operations are prosecuted with no cessation of more than sixty (60) consecutive days, and if they result in the production of oil, gas, or other mineral, so long thereafter as oil, gas, or other mineral is produced from said land or acreage pooled therewith. In the event a well or wells producing oil or gas in paying quantities should be brought in on adjacent land and within one hundred fifty (150) feet of and draining the leased premises or acreage pooled therewith, Lessee agrees to drill such offset wells as a reasonably prudent operator would drill under the same or similar circumstances.

7. Lessee shall have the right at any time during or after the expiration of this lease to remove all property and fixtures placed by Lessee on said land, including the right to draw and remove all casing. When required by Lessor, Lessee will bury all pipelines below ordinary plow depth, and no well shall be drilled within two hundred (200) feet of any residence or barn now on said land without Lessor's consent. Lessee shall be responsible for all changes caused by Lessee's operations hereunder other than damages necessarily caused by the exercise of the rights herein granted.

8. The rights of either party hereunder may be assigned in whole or in part, and the provisions hereof shall extend to their heirs, successors, and assigns; but no change or division in ownership of the land, rentals, or royalties, however accomplished, shall operate to enlarge the obligations or diminish the rights of Lessee; and no change or division

Figure 7-1: Illustrative Oil and Gas Lease (continued)

in such ownership shall be binding on Lessee until thirty (30) days after Lessee shall have been furnished by registered U.S. mail at Lessee's principal place of business with a certified copy of recorded instrument or instruments evidencing same. In the event of assignment hereof in part, liability for breach of any obligations hereunder shall rest exclusively upon the owner of this lease or of a portion thereof who commits such breach. In the event of the death of any person entitled to rentals hereunder, Lessee may pay or tender such rentals to the credit of the deceased until such time as Lessee is furnished with proper evidence of the appointment and qualifications of an executor or administrator of the estate, or if there be none, then until Lessee is furnished with evidence satisfactory to it as to the heirs or devices of the deceased and that all debts of the estate have been paid. If at any time two or more persons are entitled to participate in the rental payable hereunder, Lessee may pay or tender said rental jointly to such persons or to their joint credit in the depository named herein; or, at Lessee's election, the proportionate part of said rental to which each participant is entitled may be paid or tendered to him separately or to his separate credit in said depository; and payment or tender to any participant of his portion of the rentals hereunder shall maintain this lease as to such participants. In event of assignment of this lease as to a segregated portion of said land, the rentals payable hereunder shall be apportionable as between the several leasehold owners ratably according to the surface area of each, and default in rental payment by one shall not affect the rights of the other leasehold owners hereunder. If six or more parties become entitled to royalty hereunder, Lessee may withhold payment thereof unless furnished with a recordable instrument executed by all such parties designating an agent to receive payment for all.

9. The breach by Lessee of any obligation hereunder shall not work a forfeiture or termination of this lease nor be cause for cancellation hereof in whole or in part save as herein expressly provided. If the obligation should require the drilling of a well or wells, Lessee shall have ninety

Figure 7-1: Illustrative Oil and Gas Lease
(continued)

(90) days after the receipt of written notices by Lessee from Lessor specifically stating the breach alleged by Lessor within which to begin operations for the drilling of any such well or wells; and the only penalty for failure to do so shall be the termination of this lease save as to forty (40) acres for each well being worked on or producing oil or gas, to be selected by Lessee so that each forty (40) acre tract will embrace one such well. After the discovery of oil, gas, or other mineral in paying quantities on said premises, Lessee shall reasonably develop the acreage retained hereunder, but in discharging this obligation it shall in no event be required to drill more than one well per forty (40) acres of the area retained hereunder and capable of producing oil, gas, or other mineral in paying quantities.

10. Lessor hereby warrants and agrees to defend the title to said land and agrees that Lessee at its option may discharge any tax, mortgage, or other lien upon said land, either in whole or in part, and in event Lessee does so, it shall be subrogated to such lien with right to enforce same and apply rentals and royalties accruing hereunder toward satisfying same. Without impairment of Lessee's rights under the warranty in event of failure of title, it is agreed that if Lessor owns an interest in said land less than the entire fee simple estate, then the royalties and rentals to be paid Lessor shall be reduced proportionately. Failure of Lessee to reduce rentals paid hereunder shall not impair the right of Lessee to reduce royalties.

11. Should Lessee be prevented from complying with any express or implied covenant of this lease, from conducting drilling or reworking operations thereon, or from producing oil or gas therefrom by reason of scarcity of or inability to obtain or to use equipment or material, or by operation of *force majeure*, or any federal or state law or any order, rule, or regulation of governmental authority, then while so prevented, Lessee's obligation to comply with such covenant shall be suspended and Lessee shall not be liable in damages for failure to comply therewith; and this lease shall be extended while and so long as Lessee is prevented by any such cause from conducting drilling or reworking operations on or from

Figure 7-1: Illustrative Oil and Gas Lease (continued)

producing oil or gas from the leased premises; and the time while Lessee is so prevented shall not be counted against Lessee, anything in this lease to the contrary notwithstanding.

12. The undersigned Lessor, himself and his heirs, successors and assigns, hereby surrenders and releases all rights of homestead in the premises herein described, in so far as said rights of homestead may in any way affect the purpose for which this lease is made as recited herein, and agrees that the annual drilling deferment rental payments made to Lessor as herein provided will fully protect this lease as to the full interests of the undersigned.

[Signatures of Parties]

Note: See Appendices 6 and 7 for other illustrative lease forms.

OPERATING AND NONOPERATING MINERAL INTERESTS

The lessee in a mineral lease has rights and obligations associated with drilling and equipping wells and producing the oil and gas found. Thus, the lessee is said to possess the *operating interest* or *working interest* in the property. On the other hand, the lessor has the right to receive a specified fractional share of the minerals produced from the property or the value thereof. The lessor or royalty owner has no right or obligation to carry out exploration, drilling, or production activities; the lessor bears no part of the costs incurred in such operations except a proportionate share of production taxes or severance taxes and, where applicable, a share of costs necessary to make the oil or gas salable. Thus, the lessor (royalty owner) is said to possess a *nonoperating interest*.

The basic royalty is not the sole nonoperating interest that may be created out of the *mineral rights* in a property. Three other types of nonoperating interests are found, all created out of the *working interest.*

These are (1) *overriding royalties,* (2) *production payments (oil payments or gas payments)*, and (3) *net profits interests*. These three nonoperating interests are examined in detail in later chapters but will be discussed briefly at the end of this chapter.

The terms *mineral rights* and *mineral interests* may be synonymous to a landman but not to a petroleum accountant. Mineral rights usually refer to fee ownership rights not created by lease. For purposes of applying FAS 19, 25, and 69, the term mineral interests means more than fee ownership and encompasses leasehold interests such as working interests, royalty interests, overriding royalties, net profits interests, and some production payments.

GENERAL LEDGER ACCOUNTS FOR UNPROVED MINERAL INTERESTS

All capitalized costs related to unproved mineral properties are charged to the appropriate unproved mineral properties accounts. A single general ledger account, Unproved Mineral Properties, may be maintained. In this event, the company would keep appropriate subsidiary accounts for each type of unproved mineral interest owned as well as detailed records for each individual property. On the other hand, separate general ledger accounts may be maintained for each major type of unproved mineral interest and subsidiary records kept for each individual property. The chart of accounts illustrated in Appendix 5 includes the following general ledger accounts for unproved mineral interests:

- 210 Unproved Property Purchase Suspense
- 211 Unproved Leaseholds (detailed by lease)
- 219 Allowance for Impairment of Unproved Properties
  (detailed by property or by groups of properties as appropriate)

Other separate, similar unproved property accounts may be used for other types of economic interests, such as #212 for fee interests, #213 for royalty interests, #214 for overriding royalty interests, #215 for net profits interests, and #216 for volume production payments.

ACCOUNTING FOR UNPROVED MINERAL LEASEHOLD ACQUISITIONS

Account 211, Unproved Leaseholds, reflects the capitalized costs of unproved mineral leaseholds. The costs involved are discussed in the following paragraphs.

BONUS PAYMENTS

The lease bonus, ordinarily the initial investment in an unproved lease, must be capitalized as part of the property cost for financial accounting purposes. For example, Our Oil Company acquires a lease on 640 acres from Landowner Smithers, paying a lease bonus of $100 per acre. The lease is assigned the number 24002. The $64,000 lease bonus becomes the initial capitalized cost of the lease. The acquisition of the Smithers' lease would be recorded as follows:

211	Unproved Leaseholds, Lease No. 24002	64,000	
	301 Vouchers Payable		64,000

To record lease bonus on acquisition of Smithers lease.

INCIDENTAL LEASE ACQUISITION COSTS

Oi5.106 and Reg. S-X Rule 4-10(a)(14) provide that the cost of a mineral property includes such incidental costs as "broker's fees, recording fees, legal costs, and other costs incurred in acquiring properties." For example, if legal fees of $400 were paid in connection with the acquisition of the Smithers lease previously discussed, the costs would be recorded as follows:

211	Unproved Leaseholds, Lease No. 24002	400	
	301 Vouchers Payable		400

To record legal fees incurred in connection with acquisition of Smithers lease.

Similar entries would, conceptually, be made for recording fees and other acquisition costs. However, if the amount of such fees is insignificant, many companies charge the costs to expense at the same time they are incurred because the additional burden of analyzing and properly allocating such costs may exceed the theoretical benefits derived from their capitalization. Most companies require a minimum amount (for example, $100) for an expenditure to be capitalized.

Oi5 is silent on the proper treatment of overhead costs related to activities involved in acquiring mineral properties in identifying and acquiring leases, an E&P company may incur interval costs for such functions as scouting, civil engineering, surveying and mapping. One of the problems faced in properly accounting for such costs, usually referred to as *leasing costs,* is that personnel in these functions are often engaged not only in lease activities but also in servicing leases already acquired, assisting in drilling operations, working in exploration activities, and even working on producing leases.

Conceptually, a successful efforts company could account for the costs incurred by its own leasing staff in one of three ways:

1. Expense all leasing costs at the time they are incurred.
2. Capitalize all leasing costs, allocating the costs on an acreage basis or equally to all leases taken during the period.
3. Capitalize those costs that can be associated with specific lease acquisitions, charging the balance to current operating expense.

From the viewpoint of accounting theory, the last method is perhaps the most desirable; however, the practical difficulties involved are great and in many cases prohibitive. If detailed time sheets are maintained for personnel, it might be possible to determine the labor costs directly applicable to specific leasing deals. Similarly, operating costs of equipment may be charged to individual properties if adequate records of use and costs are kept. However, the bulk of leasing costs are not directly traceable to specific leases and must be allocated on some predetermined basis if they are to be capitalized.

One possible procedure might be to accumulate in a suspense account all those leasing costs applicable to an area of interest, in much the same way that exploration costs are accumulated by areas of interest for tax purposes. Then the entire amount applicable to the area might be capitalized on an acreage basis to any leases acquired, or the accumulated costs might be allocated between acreage leased and that not leased on an acreage basis, with the former being capitalized and the latter charged to expense. Conceptually, too, it might be argued that all leasing costs should be capitalized, dividing the total outlay among all leases acquired during the year; however, this practice would certainly not be within the intent of Oi5 for companies using the successful efforts method.

Because of the practical difficulty involved, Our Oil Company treats all leasing overhead costs as current operating expenses. The *1999 PricewaterhouseCoopers Survey of U.S. Petroleum Accounting Practices* reports that 32 of 35 responding companies using the successful efforts method charge all internal land department costs to current expense. A full cost company would capitalize all overhead costs directly related to acquisition, exploration, and development activities. According to Reg. S-X Rule 4-10(c)(2):

> Any internal costs that are capitalized shall be limited to those costs that can be directly identified with acquisition, exploration, and development activities undertaken by the reporting entity for its own account, and shall not include any costs related to production, general corporate overhead, or similar activities.

OPTIONS TO ACQUIRE LEASEHOLD

An operator may not be sufficiently interested in an area to pay the bonuses necessary to acquire leases but may wish to acquire rights to shoot seismic with an option to lease any part or all of the acreage covered by the option. Oi5.108(a) requires that *shooting rights* be expensed but lease option costs be capitalized. Ideally, the option agreement would specify how much is paid for shooting rights and how much is paid for the lease option. Often the entire option payment covering all the acreage is capitalized as cost of any acreage leased, just as it is for federal income tax purposes. If none of the acreage is leased, the option's entire cost is charged to expense. This treatment can be illustrated by the following example.

On June 12, 2000, Our Oil Company pays Landowner Klien $1 an acre for the right to explore a 1,200-acre tract and $2 per acre for the right to take five-year leases within the next six months on any part of the 1,200 acres by paying a lease bonus of $50 per acre at the time the option is exercised. On December 12, 2000, Our Company exercises the option on 500 acres, acquiring one lease, assigned No. 24019, and allows the option on the remaining 700 acres to lapse.

The journal entries required if the entire option payment is to be capitalized as cost of any acreage leased would be as follows:

June 12:

210	Unproved Property Purchase Suspense	2,400	
801	G&G Expenses, Shooting Rights	1,200	
	301 Vouchers Payable		3,600

To record cost of lease option and G&G rights on 1,200-acre Klien tract.

December 12:

211	Unproved Leaseholds, Lease No. 24019	27,400	
	210 Property Purchase Suspense		2,400
	301 Vouchers Payable		25,000

To record lease of 500 acres from Klien. Option on 700 remaining acres allowed to lapse.

If no acreage had been leased by December 12, the entire amount held in suspense would have been expensed as follows:

806	Impairment, Amortization, and Abandonment of Unproved Properties	2,400	
	210 Unproved Property Purchase Suspense		2,400

To record lapse of options on Klien 1,200-acre tract.

Some successful efforts companies capitalize only that portion of the option cost applicable to the acreage leased, charging to Impairment, Amortization, and Abandonment of Unproved Properties the portion applicable to acreage on which the option lapses. Under this procedure, the entry to record the lease option exercise in the preceding example is as follows:

December 12:

211	Unproved Leaseholds, Lease No. 24019	26,000	
806	Impairment, Amortization, and Abandonment of Unproved Properties	1,400	
	201 Unproved Property Purchase Suspense		2,400
	301 Vouchers Payable		25,000

To record exercise of option on 500 acres of Klien property (No. 24019) and lapse of option of remaining 700 acres.

A full cost company would, of course, capitalize all option payments regardless of whether any acreage is taken.

ACCOUNTING FOR ACQUISITION OF FEE INTERESTS IN PROPERTY

Although an oil operator typically obtains mineral rights through an oil and gas lease, there may be occasions when the fee interest in a property (i.e., outright ownership of both minerals and the surface) will be obtained. In this case the purchase price (including incidental acquisition costs) should be equitably allocated between the minerals and surface rights. Theoretically, the allocation would be made on the relative fair market values of the two interests. However, as a practical matter, it may be simpler to allocate to that element whose value is more clearly determinable an amount equal to its value. The residual cost is then allocated to the other property interest.

For example, assume that Our Company paid $1,000 per acre for the fee interest in 500 acres, with the surface to be held for investment purposes. In recent transactions in the immediate vicinity of the property, surface rights in similar land without any minerals attached had sold for $900 per acre. The entry could be as follows:

184	Land	450,000	
212	Unproved Fee Interests	50,000	
301	Vouchers Payable		500,000

To record purchase of the fee interest in land and minerals.

ACCOUNTING FOR MAINTENANCE AND CARRYING COSTS OF UNPROVED PROPERTIES

In addition to the acquisition of leases, the land department has responsibility for maintaining adequate property records and assuring that leases are kept in force with good title until the property becomes productive or a decision is made to surrender or abandon the acreage. The principal maintenance costs are delay rentals, *ad valorem* taxes, legal costs for title defense, and clerical costs. Oi5.108 and .109 require such carrying costs to be expensed as incurred.

RENTALS

Normally no payment other than the bonus is necessary to keep the lease contract in force for a period of one year after the lease is signed. However, as discussed earlier in this chapter, on or before the first anniversary date of the lease, a rental (delay rental) must be paid for the privilege of deferring commencement of drilling operations for an additional year within the primary term. If operations have not commenced or the delay rental is not paid by the anniversary date, the lease automatically terminates on the anniversary date. Oi5 stipulates that for a successful efforts company delay rentals must be charged to expense as incurred.

For example, the 640-acre Landers lease No. 24078 calls for an annual delay rental of $1,280. Operations have not commenced on the first anniversary of the lease, but the company wishes to keep the lease in force, so it pays the rental. The entry to record the voucher payment of the delay rental is as follows:

802 Carrying and Retaining Undeveloped Properties-Delay Rentals, Lease 24078	1,280	
301 Vouchers Payable		1,280

To record annual delay rental expense on the Landers lease.

A full cost company capitalizes delay rentals as well as all other maintenance costs of unproved properties.

When unproved properties are bought or sold, it is important to realize that the industry accounting practices of fully expensing (successful efforts) or capitalizing (full cost) delay rentals are at odds with the economic substance of delay rentals being prepaid expenses. An acquired property's nominal price is typically increased for seller's *prepaid expenses* at the sales date. If the property's nominal price is to be adjusted upwards for delay rentals as prepaid expenses, the rental would typically be prorated over the 12-month rental period. For example, an unproved, undeveloped lease with an anniversary date of March 31 is sold for a $20,000 nominal price as of June 30. The $4,000 delay rental paid in the preceding February or March provides a $3,000 prepaid expense as of June 30, increasing the adjusted sales price to $23,000.

Unless clarified in the sales agreement, the property seller and buyer may disagree on whether prepaid expenses include rentals, since rentals are not expressly viewed as prepaid expenses under successful efforts or full cost accounting, only under general accounting theory and Canadian accounting practices. A sales agreement that calls for adjusting the sales price for rentals and other costs paid prior to the sales date but incurred or accruable after the sales date under GAAP can be confusing since GAAP has two or three ways to account for delay rentals.

If the sales agreement calls for adjusting the nominal sales price for prepaid expenses, including rentals, the buyer should be cautious that the nominal sales price has not already reflected the economic benefit and value of the prepaid rental.

Contrary to commentary in FAS 19, Paragraph 195, delay rentals can enhance the future benefits of the lease. Delaying drilling operations for several months by paying a delay rental can, under various circumstances, significantly reduce drilling costs, increase revenue, or allow current drilling and production activity near the property to provide valuable additional information on whether to drill and how best to drill.

Starting the drilling operations on the rental due date and continuing the drilling after the due date eliminates the need for paying the rental. A rental is thus prospective, not retrospective. From year to year, the accrual accounting for recurring, relatively small prepaid expenses (such as a typical E&P company's delay rentals as a group) would not be much different to the company's annual income than expensing such costs as incurred. Thus, the error in FAS 19 paragraph 195 as to the nature and economic substance of delay rentals does not significantly affect financial reporting practices. However, the issue can be significant to property sellers and buyers as to the adjusted sales prices of unproved properties.

PROPERTY TAXES ON UNPROVED LEASES

Many state and local government units levy property taxes on mineral interests as well as on the surface rights. A property tax on mineral rights owned by the lessee is merely another carrying cost of the property and is charged to expense. Note that the taxes involved in this situation are incurred *after* the lessee has acquired the mineral rights and are not to be confused with the delinquent taxes assumed by the lessee at the time of acquiring the lease (a situation illustrated previously). If the property tax assessed on the Landers lease is $500, the entry to record the expense is as follows:

802.002	*Ad Valorem* Taxes, Lease No. 24078	500	
301	Vouchers Payable		500

To record property taxes on the Landers lease.

OTHER CARRYING COSTS

Other types of lease maintenance and carrying costs, such as clerical costs and other recordkeeping costs and legal expenses for title defense, would be charged to expense under the successful efforts method in the same manner as delay rentals and property taxes; these costs would be capitalized under full cost.

ACCOUNTING FOR IMPAIRMENT AND ABANDONMENT OF UNPROVED LEASES

Generally between 70 percent and 90 percent of the unproved acreage acquired by an operator will be surrendered or abandoned without production having been obtained. A number of methods have traditionally been used to provide for these known or reasonably anticipated losses. Oi5 and Reg. S-X Rule 4-10 provide general guidance to be used by successful efforts companies (and in certain cases full cost companies as explained in Chapter Nineteen) to account for the diminution of value of unproved properties. The rules for impairment of unproved properties were specifically not changed by FAS 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of*.

Under Oi5, unproved properties must be assessed periodically, in no case less frequently than annually, to determine whether their book values have been *impaired*. If impairment has occurred, a valuation allowance should be established to reflect the diminution in value. Although Oi5 does not define impairment, Oi5.119 does suggest that

> [a] property would likely be impaired, for example, if a dry hole had been drilled on it and the enterprise has no firm plans to continue drilling. Also, the likelihood of partial or total impairment of a property increases as the expiration of the lease term approaches if drilling activity has not commenced on the property or on nearby properties.

The SEC's Codification of Financial Reporting Releases §406.01.c.i (see the Appendix 1 addendum) adds that ". . . unevaluated properties are required to be assessed periodically for impairment and to have value at least equal to their carrying costs (including any capitalized interest). . . ." but *value* is not defined.

There are two ways in which the impairment of value may be recognized, depending on whether the cost of an individual property is significant. The method used to record impairment also determines how the costs of abandoned leases and the costs of leases transferred to proved properties will be handled.

RECORDING IMPAIRMENT OF INDIVIDUAL PROPERTIES

If costs associated with an individual property are significant, impairment must be assessed on a property-by-property basis. Individual impairment may also be, but is not required to be, recorded on leases that are not individually significant. For successful efforts, it is unclear what are *individually significant* properties, but for full cost accounting the SEC has stated that *individually significant* generally means a property with capitalized costs exceeding ten percent of the net capitalized costs of the country-wide cost center.[15]

Responses to the *1999 PricewaterhouseCoopers Survey of U.S. Petroleum Accounting Practices* indicated that companies generally use various criteria for determining significance. Some major companies have established a specific dollar amount as a minimum cost for a property to be deemed significant. Presumably a company has arrived at a floor after considering the size of the company, its total assets, its total investment in oil and gas properties, its net income, and similar factors. Each year acquired leases are examined in light of the factors previously listed.[16]

The concept of impairment of unproved property introduced in FAS 19 is somewhat unusual in authoritative accounting literature. Unfortunately, neither the FASB nor the SEC has defined the term, nor has either clearly indicated how impairment of an individual unproved property is to be measured. However, the *1999 PricewaterhouseCoopers Survey of U.S. Petroleum Accounting Practices* found that companies considered various factors in assessing impairment. Over 90 percent of the respondents considered whether the company still intended to drill on the lease. The majority of respondents also considered (1) other wells drilled in the area, (2) the geologist's valuation of the lease, and (3) remaining months in the lease's primary term. Only 8 of 27 respondents considered the market value of similar acreage.

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[15] SEC's Codification of Financial Reporting Releases, §406.01.c.i, reproduced in Appendix 1, page App. 1-17.

[16] See Section C of the *1999 PricewaterhouseCoopers Survey of U.S. Petroleum Accounting Practices* for further insights.

Below are several examples of impairment assessment considering such factors:

- If the company has definite plans to drill on a lease, its assessed value might be equal to net book value whereby no impairment is recognized;
- If drilling is only likely, the company's assessed value of the lease may be significantly less than original cost;
- If the company has no plans to drill on a lease due to recent dry hole(s) on or close to the company lease, then that lease may have little or no assessed value and be substantially impaired; and
- A company's impairment policy might recognize partial impairment as time elapses on the primary term of each lease.

To illustrate impairment of significant leases, assume that a company has five significant leases for which no impairment has previously been recorded. Costs and assessed values on December 31, 2000, are as shown in the following table:

	Cost	Assessed Value	Impairment
Lease A	$100,000	$ 85,000	$ 15,000
Lease B	110,000	100,000	10,000
Lease C	400,000	300,000	100,000
Lease D	125,000	190,000	0
Lease E	45,000	500,000	0
	$780,000	$1,175,000	$125,000

Since each lease is deemed to be significant, the assessment must be made on a lease-by-lease basis. Even though the total value exceeds total cost, impairment of any single lease is still recognized.

The entry to record the impairment of value in the above instance would be as follows:

December 31:

806 Impairment, Amortization, and Abandonment of Unproved Properties	125,000	
219 Allowance for Impairment of Unproved Properties		125,000
To record loss on impairment of individual leases for the period.		

After impairment has been recorded, the net book value of unproved properties for the example above would be as follows:

Unproved Properties	$780,000
Less: Allowance for Impairment, Unproved Properties	(125,000)
Net	$655,000

Surrender of Impaired Significant Unproved Property

When an impaired significant property is surrendered, the net carrying value (capitalized cost minus valuation allowance) of that lease should be charged to expense under successful efforts or to Account 227, Abandoned Properties, under full cost. For example, assume that in 2001 leases *A* and *D* in the preceding example are abandoned. The entries, using Appendix 5's chart of accounts for Our Oil Company, would be:

219 Allowance for Impairment of Unproved Properties	15,000	
806 Impairment, Amortization, and Abandonment of Unproved Properties	85,000	
211 Unproved Leaseholds		100,000
To record surrender of lease *A*.		

806 Impairment, Amortization, and Abandonment of Unproved Properties	125,000	
211 Unproved Leaseholds		125,000
To record surrender of lease *D*.		

Subsequent Evaluation

After recording impairment, a company cannot record any recovery in value. For example, assume that on December 31, 2001, the company in the preceding illustration prepares the following schedule of unproved properties.

	Net Cost	Value	Calculated Impairment
Lease *C*	$ 300,000	$680,000	$ 0
Lease *E*	45,000	500,000	0
Lease *F* (new)	1,000,000	800,000	200,000

An impairment of $200,000 would be recorded on lease *F* acquired in early 2001 by the usual entry. Even though the value of lease *C* now exceeds its cost, the allowance for impairment of $100,000 set up on December 31, 2000, would not be changed. No *gains* on increases in value of such properties are ever recorded. On the other hand, if the value of lease *C* on December 31, 2001, had declined to only $235,000, it would be necessary to increase the related allowance for impairment from $100,000 to $165,000, recording an additional loss of $65,000.

RECORDING IMPAIRMENT ON A GROUP BASIS

For companies using the successful efforts method, Oi5.119 provides that:

> When an enterprise has a relatively large number of unproved properties whose acquisition costs are not individually significant, it may not be practical to assess impairment on a property-by-property basis, in which case the amount of loss to be recognized and the amount of the valuation allowance needed to provide for impairment of those properties shall be determined by amortizing those properties, either in the aggregate or by groups, on the basis of experience of the entity in similar situations and other information about such factors as the primary lease terms of those properties, the average holding period of unproved properties, and the relative proportion of such properties on which proved reserves have been found in the past.

In computing amortization to reflect impairment, all of an entity's unproved properties may be placed in a single group, or multiple groups may be used. If multiple groups are used, the aggregation may be based on geographic location (onshore, offshore, Gulf Coast, etc.); dollar cost ($500,000 or less, $500,000 to $1,000,000, $1,000,000 to $10,000,000, etc.); geologic area (Tuscaloosa Trend, Permian Basin, etc.); year of acquisition (2000, 2001, 2002, etc.); or some other logical basis. The basic intent should be to derive an overall estimate of impairment that reflects the impairment that has actually occurred on individual properties.

Several approaches are used to estimate the annual impairment provision on a group basis. They may be classified under two major headings:

1. Methods that emphasize the expense computation, based on the average holding period for properties in each group, and
2. Methods that emphasize the balance sheet valuation by maintaining the valuation account at some predetermined percentage of the unproved properties account.

Impairment Procedures Emphasizing Amortization Expense

Since the basic notion underlying group amortization is that properties that *will not* become productive over time should be *impaired* while properties that *will* become productive should not be impaired, it is necessary to estimate the portions of properties that will not become productive. This estimate should generally be based on the company's past experience. If the company's area of activities or strategy of exploration has changed or if the company has no previous experience, it may be appropriate to utilize industry-wide experience.

Straight-Line Amortization. If a company carried out drilling on a relatively even basis over the terms of its leases, it might be appropriate to record impairment of the expected worthless leases on a straight-line basis over the lease terms.

Some companies using straight-line amortization apply the rate to the balance of the unproved property account (which reflects additions, surrenders, transfers to proved properties, etc.). Others apply the rate to the net book value of unproved properties (the balance of unproved properties minus the balance of the allowance for impairment). However, since the amortization rate is usually based on the original acquisitions, that should be the basis for the computation. If a group includes properties acquired in more than one year, the amortization rate should be applied separately to the leases acquired each year.

To illustrate a simple application of the group method of recording impairment, using a straight-line rate, assume that a company includes all of its unproved properties in a single group and records amortization on that basis. Assume that as of December 31, 2000, the balances of the Unproved Leaseholds account and the Allowance for Impairment account were $4,000,000 debit and $1,980,000 credit, respectively.

The company keeps a record of leases acquired each year and makes a separate computation for each year's acquisitions. An analysis of leases acquired in only one year, 1999, shows that the acquired unproved leaseholds cost $1,200,000 and were charged, along with leases acquired in other years, to the Unproved Leaseholds account.

Experience indicates that ultimately 20 percent of the leases will become productive and that the average holding period of the remaining leases is four years. Thus $960,000 ($1,200,000 x 80%) of the leases acquired in 1999 will ultimately be abandoned over an average period of four years. Amortization of $240,000 may be recorded for the year 2001 as shown in the following entry:

806 Impairments and Abandonments of Unproved Properties	240,000	
219 Allowance for Impairment of Unproved Properties		240,000
To record amortization of unproved properties.		

Note that in this calculation the beginning balance in the Allowance for Impairment of Unproved Properties account is ignored.

Similar calculations would be made for leases acquired in each year, and the amortization recorded in the same way. Assume that amortization on other leases totaled $560,000 for the year 2001, so that the total amortization for 2001 was $800,000.

When impairment of individually insignificant properties is measured and recorded on a group basis, accounting for the surrender of unproved properties and transfers to proved properties is simplified. The original capitalized cost of a surrendered lease is charged to the Allowance for Impairment account and is removed from the Unproved Leaseholds account at the time of surrender. The Proved Leaseholds account is charged and the Unproved Leaseholds account is credited for the cost of a property that is proved during the period. For example, continuing the above illustration, assume that the following occurred in 2001:

1. Additional unproved properties were leased for $1,600,000.
2. Leases that cost $750,000 were surrendered.
3. Leases that cost $320,000 were proved.

The transactions would be recorded as follows:

211 Unproved Leaseholds	1,600,000	
306 Vouchers Payable		1,600,000
To record cost of leases acquired during year.		
219 Allowance for Impairment of Unproved Properties	750,000	
211 Unproved Leaseholds		750,000
To record cost of surrendered leases.		
221 Proved Leaseholds	320,000	
211 Unproved Leaseholds		320,000
To record cost of properties proved during the year.		

After these transactions have been entered, the Unproved Leaseholds account and the Allowance for Impairment account would appear as follows:

#211	Unproved	Leaseholds	
12/31/00 Balance	$4,000,000	2001 Surrenders	$750,000
2001 Additions	1,600,000	2001 Proved	320,000
12/31/01 Balance	$4,530,000		

#219 Allowance for Impairment of Unproved Properties			
		12/31/00 Balance	$1,980,000
2001 Surrenders	$750,000	2001 Amortization	800,000
		12/31/01 Balance	$2,030,000

The amortization for 2002 on leases acquired in 1999 would again be $240,000 and, assuming that the company's estimate of surrenders has not changed, amortization on leases acquired in 2001 would be $320,000 (1/4 x 80% x $1,600,000). Those amounts, along with amortization on acquisitions of other years, would be charged to Account 806, Impairment . . . of Unproved Properties, and credited to Account 219, Allowance for Impairment of Unproved Properties. If the allowance previously provided should be inadequate to absorb the cost of a surrendered lease, a loss equal to the difference between the cost of the property surrendered and the balance in the Allowance for Impairment account should be recognized upon the surrender of a property.

Amortization Based on Analysis of Yearly Surrenders. Another approach for computing amortization is to use annual rates based on past experience. In developing its experience pattern, the company should use at least one complete cycle of lease acquisition and exploration, using either all leases acquired during the base period, or a representative sample of leases. It may be appropriate to base the calculations on monetary amounts or, especially when leasehold costs per acre are fluctuating widely, on acreage. To illustrate this approach, assume that a company has analyzed its cycle for leases with primary terms of four years. A three-year recurring analysis as of early 2000, based on acreage, is shown below.

		Ultimate Cost Allocation				
		Property Found To Be Nonproductive In Year:				Ultimately Productive
Year Acquired	Total Cost	1	2	3	4	Property
1995	$ 45,000	*	*	*	$16,000	$ 4,000
1996	60,000	*	*	$21,000	20,000	6,000
1997	50,000	*	$ 8,500	17,000	10,000	6,000
1998	100,000	$ 7,000	14,500	31,000	**	**
1999	70,000	6,800	15,500	**	**	**
2000	80,000	7,500	**	**	**	**
Totals		$21,300	$38,500	$69,000	$46,000	$16,000
3 yr avg %***		9%	18%	33%	30%	10%

*Known but not part of the latest three-year average.
**Unknown at the time of analysis in early 2000.
***For example, 21,300/(100,000 +70,000 + 80,000) = 9%.

This history suggests that 90 percent of the costs relate to leases that are ultimately nonproductive and become partially impaired as time passes until the leases are found to be worthless. There are at least three ways to calculate the annual amortization rates for the 90 percent of costs expected to be found worthless. First, use a straight-line calculation over the four-year primary term whereby annual amortization is one-fourth of 90 percent or 22.5 percent as shown in Table 1 below. Second, calculate annual amortization rates by allocating costs over the properties' expected lives; e.g., for the 18 percent of costs related to properties expected to be found worthless and abandoned in Year 2, assume half is impaired and expensed in Year 1 and half in Year 2 as shown in Table 2 below. Third, calculate the amortization by allocating a specific portion (say 20 percent) in each year prior to the expected year of abandonment; e.g., for the 18 percent of costs related to properties expected to be abandoned in Year 2, assume 20 percent of 18 percent or 3.6 percent is impaired and expensed in Year 1 and 14.4 percent in Year 2 as shown in Table 3 below. The third approach should reflect management's judgment and experience that leases retain much of their value until the year found to be nonproductive.

Table 1:

Aban.	Allocated Straight-Line Over Four Years			
%	1	2	3	4
90.0%	22.5%	22.5%	22.5%	22.5%

Table 2:

Year after	Aban.	Allocated Str. Line Over Expected Life			
acquisition	%	1	2	3	4
1	9.0%	9.0%			
2	18.0%	9.0%	9.0%		
3	33.0%	11.0%	11.0%	11.0%	
4	30.0%	7.5%	7.5%	7.5%	7.5%
	90.0%	36.5%	27.5%	18.5%	7.5%

Table 3:

Year after	Aban.	Allocated at 20%/yr. Until Worthless			
acquisition	%	1	2	3	4
1	9.0%	9.0%			
2	18.0%	3.6%	14.4%		
3	33.0%	6.6%	6.6%	19.8%	
4	30.0%	6.0%	6.0%	6.0%	12.0%
	90.0%	25.2%	27.0%	25.8%	12.0%

Notice in the tables that first-year amortization varies from 22.5 percent to 36.5 percent but always exceeds the 9 percent of costs that is attributable to leases expected to be found worthless in Year 1.

For this example, one should not calculate first-year amortization as simply 9 percent of costs; otherwise, the accounting is merely expensing the estimated costs of worthless property in the year found worthless. Amortization is intended to reflect lease *impairment*, including partial impairment after one year for leases expected to be found worthless in Years Two, Three, and Four. First-year amortization needs to reflect both (1) the 9 percent of costs and (2) a portion of the 81 percent of total lease acquisition costs that will be found worthless in the primary term.

Impairment Procedure Emphasizing Asset Valuation

A simple approach to measuring the impairment of a group of unproved properties is to adjust the Allowance for Impairment account to some predetermined percentage of Unproved Leaseholds. Lease acquisitions, abandonments, and transfers to unproved properties are handled in the way described earlier.

For example, suppose that past experience of a company has indicated that approximately 80 percent of its unproved leases are abandoned, so the company has adopted a policy of maintaining the Allowance for Impairment account at 80 percent of the Unproved Leaseholds account. This approach is conservative in that for every $100 of new lease acquisition costs, $80 is immediately considered to be impaired. Some companies would adjust the allowance account to only 40 percent of the Unproved Leaseholds account on the theory that on the average only one half of the leases that will ultimately be worthless are impaired at any balance sheet date. For example, assume that as of December 31, 2000 the two balance sheet accounts involved were as follows before annual impairment was recorded:

#211	Unproved	Leaseholds
11/30/00 Balance	$10,000,000	
12/00 Acquisitions	5,000,000	
12/31/00 Balance	$15,000,000	

#219 Allowance for Impairment	of Unproved Properties	
	12/31/00 Balance	$4,000,000

Since the balance of the allowance account on December 31, 2000, is only $4,000,000 and a balance of $6,000,000 (40% of $15,000,000) is needed, the following entry would be necessary to adjust the account.

806	Impairment and Abandonment of Unproved Properties	2,000,000	
	219 Allowance for Impairment of Unproved Properties		2,000,000

To adjust allowance account to desired balance.

This simplified procedure would appear to be appropriate only if acquisitions and surrenders are relatively stable from year to year and the company has many unproved properties not individually significant.

MEASURING IMPAIRMENT OF INDIVIDUAL PROPERTIES UNDER FULL COST ACCOUNTING

Under full cost, companies *may* (but are not required to) exclude from the full cost amortization pool the acquisition costs of unevaluated properties and unevaluated exploration costs. If this procedure is followed, the entity is required, however, to begin immediate amortization on any amount of impairment. As in the case of successful efforts accounting, impairment of unproved properties *must* be on a property-by-property basis for properties that are individually significant. The SEC has stated that for full cost companies, *individually significant* means a property or project whose costs exceed ten percent of the net capitalized costs of the cost center.[17] Individual impairment is *allowed* for insignificant properties. This impairment for full cost companies is discussed further in Chapter Nineteen. Note that impairment of unproved properties does not give rise to an expense or loss for a full cost company; it merely accelerates the costs subject to amortization.

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[17]SEC's Codification of Financial Reporting Releases, §406.01.c.i, reproduced in Appendix 1, page App. 1-17.

UTILIZING POST-BALANCE-SHEET EVENTS IN ASSESSING IMPAIRMENT

Oi5. 130 provides that:

> information that becomes available after the end of the period covered by the financial statements but before those financial statements are issued shall be taken into account in evaluating conditions that existed at the balance sheet date, for example in assessing unproved properties [for impairment]. . . .

Suppose Our Oil Company owns a leasehold that is individually significant (cost $500,000) and has an estimated value on December 31, 2000 of $1,200,000. No impairment recognition seemed necessary on December 31, 2000. However, in February 2001, before the financial statements for 2000 were issued, another company abandoned as a dry hole a well drilled on a contiguous lease, resulting in the assessment that Our Company's lease is worth only $100,000. This *post-balance-sheet-date* information necessitates the recognition of an impairment loss of $400,000 in the 2000 income statement and establishment of an impairment allowance of $400,000 in the balance sheet as of December 31, 2000.

TRANSFERS TO PROVED PROPERTY

Transfers of unproved property acquisition costs to proved property acquisition costs take three forms:

1. An unproved property individually impaired has its net book value (NBV) transferred to proved property costs, e.g.:

219	Allowance for Impairment	10,000	
221	Proved Property Acquisition Costs	90,000	
	211 Unproved Leaseholds		100,000

2. An unproved property subject to a group impairment allowance has its gross acquisition cost reclassified, e.g.:

221	Proved Property Acquisition Costs	100,000	
	211 Unproved Leaseholds		100,000

3. A vast single property, such as a foreign concession, has reclassified only the portion of its costs (or NBV) deemed related to the proved reserves. For example, for a 50,000-acre concession including a 1,000-acre proved field, only two percent of an assumed $10,000,000 in unproved leasehold costs are reclassified:

221	Proved Property Acquisition Costs	200,000	
	211 Unproved Leaseholds		200,000

TOP LEASES AND LEASE RENEWALS

In some cases the operator may be unable to or unwilling to drill on an unproved property before expiration of its primary term but may wish to retain the property for possible future drilling. In this event, the operator may negotiate with the mineral owner to extend the primary term of the original lease or to sign a new lease contract. Under both full costing and successful efforts accounting, a bonus for signing a new lease is capitalized.

A new lease signed before expiration of the original contract is called a *top lease*. Under the successful efforts method, the book value of the original lease may be treated as a part of the capitalized cost of the top lease. If, however, the original lease expires and the lessee gives up all rights before obtaining a new lease, the expiration of the old lease should be treated as an abandonment.

Under full costing the cost of the original lease remains capitalized as part of the cost pool.

TAX TREATMENT OF UNPROVED PROPERTY ACQUISITION, MAINTENANCE, AND ABANDONMENT COSTS

For federal income tax purposes, the bonus payment and incidental acquisition costs, such as recording fees and broker's commissions, must be capitalized as depletable mineral costs. Historically, the operator has had a year-by-year and property-by-property election to either charge carrying costs, including delay rentals, to expense as they are paid or incurred, or to capitalize them as depletable leasehold costs. Almost universally, taxpayers have elected to charge carrying costs to expense.

However, the current IRS position is that delay rentals must be capitalized as depletable leasehold costs.

Costs of unproved properties must be charged off in the year they become worthless, which may be either at the same time or before the time they are abandoned or surrendered. For tax purposes, there is no deduction for partial worthlessness or impairment or for amortization of unproved property costs. When a property becomes productive, its costs become subject to depletion as the reserves are produced.

SPECIAL NONOPERATING INTERESTS CREATED OUT OF THE WORKING INTEREST

Earlier in this chapter, it was pointed out that the principal types of mineral interests are the royalty interest (a nonoperating interest) and the working interest (sometimes called the operating interest). The basic royalty interest retained by the lessor and the working interest of the lessee are created by, and limited to, the terms of the individual lease contract. However, the lessor, as owner of the permanent mineral interests, has the permanent right to negotiate new leases with new royalty terms when old leases expire.

The owner of the working interest may further divide the working interest into a number of different types of property rights and often does so in financing the development of the property and in spreading the risk of that development. Because these special property rights are of great importance in the petroleum industry and will be frequently referred to in the remainder of this text, some of the more common rights are described and explained at this point. It is important to keep in mind that these rights are created out of the working interest and that their life is, therefore, limited to the life of the working interest.

The nonoperating interests created out of the working interest may be either *retained* or *carved out.* A retained interest arises when the working interest owner transfers the basic right and responsibilities for developing and operating the property to another party and retains a special nonoperating interest created by the conveyance contract. A carved-out interest is created when the operator retains the basic working interest but grants to another entity the special nonoperating rights created by the agreement. In many cases two or more of these special nonoperating interests may be created out of the single working interest in a lease.

OVERRIDING ROYALTIES

The overriding royalty is very similar to the basic royalty interest except that it is created out of the working interest. The holder of an overriding royalty is entitled to a specific fractional share of gross production, and the overriding royalty owner has no obligation or responsibility for developing and operating the property. As in the case of the basic royalty interest, the only expenses borne by the overriding royalty owner are the royalty owner's share of production or severance taxes and sometimes costs incurred to make the oil or gas salable.

In an example of a carved-out override, Acorn Company holds a mineral lease of 500 acres in Wise County, Texas, with a 1/8 royalty interest retained by the landowner. Acorn sells an overriding royalty of 1/7 of its 7/8 working interest to Squirrel Company. As a result, Squirrel will receive 1/8 of total production (1/7 of 7/8) from the property as long as it is operated under the lease agreement. Squirrel does not bear any part of the development of operating expenses except production taxes.

To illustrate a retained override, assume that in the above case Acorn Company has assigned its working interest in the lease to Oak Company, but Acorn retained an overriding royalty of 1/8 of gross production (1/7 of the 7/8 working interest). Acorn Company will be entitled to receive 1/8 of the gross production from the property, free of any development and operating costs except, of course, the share of taxes applicable to it.

NET PROFITS INTERESTS

Net profits interests are similar to overriding royalties except that the amount to be received is a specified portion of net profit from the property. Net profit must be clearly defined in the contract. The net profits interest owner has no liability for development costs or operating expenses if production is inadequate to pay these costs. Net profits interests usually are retained interests arising from assignment of the working interest to another operator for development, but they may also be *carved out*.

An example of *retained* net profits interests follows. Acorn Company owns the working interest in a 500-acre lease. It assigns the working interest to Developco, retaining a net profits interest. Under the contract Acorn is to receive one-fourth of the net profit, as defined in the contract, that Developco realizes from operating the property. If there is no profit, Acorn will, of course, receive nothing. Under the contract Acorn will receive a share of net profit only after accumulated net losses have been offset by profits. However, Acorn has no liability for any losses incurred in operating the property.

To illustrate a *carved-out* net profits interest, assume that Acorn Company owns the working interest in the 500-acre lease in the above example, but it needs funds for developing the property. It assigns to Investor Company a one-fourth interest in the net profits of the lease for a consideration of $100,000. Procedures for measuring net profit are clearly spelled out in the assignment contract. Nothing is to be paid to Investor Company until all accumulated losses on the property have been recovered by Acorn.

A net profits interest may be limited to a specified time period or specified production volume. Such *term net profits interests* are economic interests similar to volume production payments described below.

PRODUCTION PAYMENTS

A production payment entitles its owner to recover a specified fractional part of the working interest's share of gross production until a specified sum of money or a specified number of units of mineral has been recovered or (less commonly) for a specified period of time. The production payment owner bears no part of development costs or operating expenses. As discussed in Chapter Twenty-Two, Oi5.134 provides that production payments, whose amounts are specified in money and are reasonably assured of satisfaction, are not considered to be mineral interests but are classified as receivables or payables. However, production payments whose amounts are specified in units of oil or gas (called *volume production payments*, *volumetric production payments* or VPPs) or payments specified in monetary terms but that are not reasonably assured to be paid out are classified as leasehold interests [Oi5.138(a)].

An example of a retained payment follows. Northern Oil Company owns a 500-acre developed property. It assigns the working interest to Eastern Oil Company for $100,000 cash and retains an oil production payment of $250,000. Under terms of the payment, Eastern will pay Northern $250,000 plus an amount equivalent to interest of 20 percent, payable out of the first 75 percent of the working interest's share of oil and gas produced. In the first year after the assignment, the working interest's share of production was $180,000. Of this amount $135,000 is paid over the year to Northern Oil Company. Roughly $40,000 of such payments represent interest, and roughly $95,000 represent principal repayments.

Under Oi5.134, this contract is treated as a liability by Eastern Company and a receivable by the Northern Company.

On the other hand, suppose that the production payment retained by Northern Company called for Eastern to deliver to Northern 10,000 barrels of oil out of the first 75 percent of the working interest's share of oil produced. In the first year after assignment, the working interest's share of production was 8,000 barrels, and of that amount 6,000 barrels were delivered to Northern Company (or the value thereof paid to Northern Company). Under Oi5.138(a), this production payment is treated for accounting purposes as a mineral interest owned by Northern.

To illustrate carved-out payments, assume that Northern Oil Company owns the working interest in a 200-acre producing lease. In order to get funds for operations, it carves out an oil production payment and assigns the payment to Eastern Finance Company for a cash contribution of $200,000. Under the contract Northern will pay Eastern $200,000, plus an amount equivalent to interest of 15 percent per annum on the unpaid balance of the oil production payment, payable out of the first 80 percent of the working interest's share of production. In the first year after the oil production payment was assigned, the working interest's share of production was $120,000. Of this amount, $96,000 is paid to Eastern Finance Company, $13,600 of which is interest, and the balance is a reduction of the principal amount of the oil production payment.

Figure 7-2 summarizes the creation of different types of nonoperating interests out of the working interest. Chapters Twenty-One and Twenty-Two provide additional information on conveyance of production payments, overrides, and net profits interests.

Unproved nonoperating interests are subject to the same general accounting rules governing impairment, abandonment, etc., as are mineral leaseholds.

Figure 7-2: Economic Interests Examples

1. Party A owns a mineral interest:

A Mineral Interest (MI)

2. Party A leases the property to B retaining a 1/8 Royalty Interest (RI):

1/8	1/8	1/8	1/8	1/8	1/8	1/8	1/8

A	**B**
1/8	100% Working Interest (WI)
RI	with 7/8 Net Revenue Interest (NRI)

3. Party B transfers the working interest to C and reserves a 1/8 overriding royalty interest (ORRI):

A	**B**	**C**
1/8	1/8	100% Working Interest (WI)
RI	ORRI	with 75% NRI

4. Party C carves out to D a volume production payment interest (VPP) of X quantity, payable out of 2/3rd of C's 75% NRI:

A	**B**	**D**	**C**
1/8	1/8	VPP out of 50% NRI.	100% WI &
RI	ORRI	After payout of X volume, the	25% NRI before
		50% NRI proceeds go to C.	pay out ("bpo")

5. Party C sells half the working interest to E, subject to ORRI & PPI:

A	**B**	**D**	**C**	**E**
1/8	1/8	VPP out of 50% NRI.	50% WI	50% WI
RI	ORRI	After payout of X volume, the	&12.5%	&12.5%
		50% NRI proceeds go to C&E.	NRI bpo	NRI bpo

Chapter Eight

DRILLING AND DEVELOPMENT

After subsurface formations that show potential for containing hydrocarbons have been located and leases have been acquired, actual drilling of one or more wells into the formation will be necessary to determine whether there are accumulations of oil and gas in commercial quantities.

PREPARING FOR DRILLING

Before drilling can commence, the well site must be determined and preparations made for drilling.

REGULATORY REQUIREMENTS

A permit to drill must be secured from the appropriate regulatory agency, either state or federal, before an oil or gas well may be drilled. Many jurisdictions require specific minimum *spacing* requirements, and many require that a permit be obtained before drilling can commence. In order to begin drilling, the operator must provide a minimum amount of information to the appropriate government agency, which usually includes the following:

- Proof of *financial assurance* supported by either a bond from an insurance company or a letter of credit from a bank.
- An *application to drill form*, which at a minimum requires the exact legal location (*staked* location) of the well, planned TD (total depth), spacing, target geological formation (reservoir), well type (oil or gas), distance to the nearest *completed* well in this reservoir, and lease name.
- A *plat*, which is a scaled diagram of the lease showing the proposed drilling location, spacing unit boundaries, distance to the nearest well in the same reservoir, northerly direction, scale of diagram, and legal name of the surveyed acreage.
- Payment of the applicable regulatory *drilling fee*, which usually varies by depth.

Offshore operations are far more complicated and are, therefore, discussed in greater detail at the beginning of Chapter Thirty. In many cases both a state government and the federal government have jurisdiction over an area. A great deal of information is required before a permit to drill offshore will be issued by the Minerals Management Service of the U.S. Department of Interior (MMS). Information required includes a description of the drilling vessels and platforms or other structures, along with various details about the equipment, including pollution control and prevention items, location of each well and targeted locations for directionally drilled wells, structural interpretations of exploration data, and any other information desired by the MMS.

Even though there are exceptions, a fairly common spacing in the continental United States is no more than one oil well per 40 acres and no more than one gas well per 640 acres. Greater spacing for gas wells is required because gas will move through the formation more easily than oil and thus fewer wells are needed to physically deplete a gas reservoir economically.

The total amount of oil and gas recovered (known as the ultimate recovery) from a reservoir may be only moderately affected by the number of wells drilled into the reservoir. However, the speed at which the reservoir is physically depleted is very definitely affected; and if production is accelerated beyond certain technical limits, ultimate recovery will be reduced. Given the time value of money, it can be assumed that sometimes more wells are drilled than are required to physically deplete the reservoir in order to accelerate cash flow from production, although the high cost of drilling deters overdevelopment.

ENVIRONMENTAL AND SAFETY REQUIREMENTS

Good business dictates that companies drilling for oil and gas operate in a safe and prudent manner protecting workers and the environment. As described in Chapter Thirty-Three, such practices are part of a company’s overall risk management program.

The United States Environmental Protection Agency (EPA), the Occupational Safety and Health Administration (OSHA), and state regulatory agencies have established many environmental and safety laws and regulations on all phases of the energy industry. In general, these rules promote safety and environmental protection while drilling, but some rules go so far as to prohibit drilling in certain areas of the United States such as off the coast of Florida.

Some of the regulations which affect the energy industry are the:

- Superfund Amendments Reauthorization Act (SARA Title III),
- Resource Conservation and Recovery Act (RCRA),
- Oil Pollution Act of 1990 (OPA '90),
- Comprehensive Environmental Response, Compensation and Liability Act of 1980 (CERCLA),
- Clean Air Act,
- Clean Water/Safe Drinking Water Acts,
- Emergency Response and Community Right-to-Know Act,
- Occupational Safety and Health Act's (OSHA's) Hazardous Communication Standard,
- U. S. Fish and Wildlife Service's Migratory Bird Treaty Act,
- Surface Mining Control and Reclamation Act (SMCRA), and
- State Radiation Regulations and Licensing of Naturally Occurring Radioactive Material (NORM).

The fines for noncompliance of some of the above regulations range up to $25,000 per day per incident. In some cases, criminal charges can be filed against the officers of the company with a maximum penalty of imprisonment for two years (five years for a second conviction) for knowingly and willfully failing to comply.

The difficult task of complying with the various requirements of these regulations is compounded by the fact that these regulations are constantly being changed by many different governmental agencies.

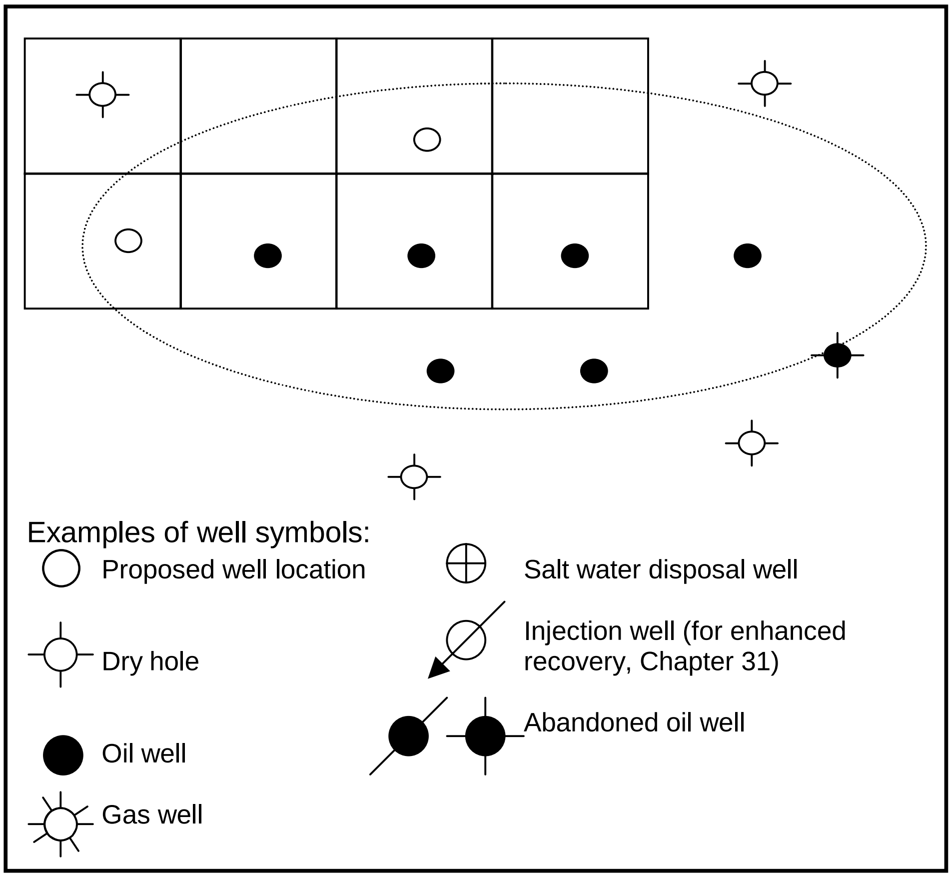
Therefore, it is extremely important to have environmental and safety studies performed on all oil and gas properties. It is also vital to have the studies continually updated in order to stay in compliance with any new and revised regulations.

The larger oil and gas companies have employees dedicated solely to environmental and safely compliance, while the smaller companies hire expert environmental and safety consultants for the same purpose.

WELL SYMBOLS

In showing well locations on maps, it is common to use symbols that depict the status of the well. Common symbols are (1) an open circle for a proposed well location or well in progress, (2) a simple black circle to indicate an oil well, (3) an open circle with eight spokes to indicate a gas well, (4) an open circle with four spokes to indicate a dry hole, (5) a circle encircling a cross to indicate a salt water disposal well, and (6) a half-black circle with spokes to symbolize a well producing both oil and gas. Figure 8-1 below illustrates the use of well symbols for a rectangular 320-acre lease having eight 40-acre drill sites, with three producing oil wells. These three wells plus three others on other lease(s) produce from an oblong reservoir. A seventh oil well produced but was later abandoned.

Figure 8-1: Field Map using Common Symbols for Wells



STAKING THE WELL

Even though necessary exploration work has been performed to justify acquiring or retaining the property, detailed geological work must be carried out to locate the well site. The most important factor to be considered is the subsurface structure. The geologists will determine the exact point in the structure that is the target area. In some broad structures this may not be of great importance, but in others it may be critical. The surface structure becomes significant only when it imposes constraints on drilling directly over the targeted area. This may be the result of natural phenomena, such as the presence of a body of water, marsh areas, hostile terrain, or other physical obstructions. Drilling constraints may also result from contractual clauses in the lease that preclude drilling within a specified distance of existing structures or within a municipality and similar restrictions. When there are surface constraints, the well site may be *staked*, or located, in a satisfactory location, and a directional well will be drilled in such a way as to *bottom out* at the targeted area.

In addition to the examination of the subsurface structure, particular attention must be given to lease and property boundaries to ensure that the well is actually drilled on the property on which the operator holds the working interest. There have been cases in which wells have been drilled on acreage owned by others; thus the importance of carefully locating the well cannot be overemphasized.

PREPARING THE LOCATION

After the well has been staked or the location determined and the necessary permits to drill have been obtained, the well site must be prepared. Several steps must be taken before actual drilling is commenced onshore. First, access to the location must be provided. In many areas, this is a simple matter; an access road is merely graded to the location. In other areas, gaining access to the location may constitute a major problem. Roads and bridges capable of handling heavy equipment may be required. For example, in swampy areas, such as portions of southern Louisiana, temporary roads may have to be built using heavy timbers. In mountainous terrain it may be necessary to bulldoze or blast roads through the mountains under hazardous conditions. After access has been provided, the well site itself must be prepared. A level site is needed for placement of the drilling rig, power supplies, mud pits, and other components. In some locations, setting up a structure to support drilling operations may be so complex that it is equivalent to building an offshore platform. A platform may actually be necessary in swampy areas and in Alaska or other Arctic areas where the permafrost must be protected from the heat generated by the drilling rig.

In offshore locations additional problems center around the requirements for carrying out the details of the drilling program originally submitted. Required navigational warnings must be installed, and environmental requirements must be met. Most offshore problems are related to transporting, installing, and positioning drilling rigs, rather than preparing the well site.

DAMAGES

Although the oil and gas lease gives the operator the right to explore for and produce oil and gas and includes the right of ingress and egress, the operator may need to pay for the use of the surface and will almost certainly pay for any damages to it. Most leases now include requirements to restore the surface to its original condition. Damage payments represent another cost of locating and preparing the well site prior to commencement of drilling operations.

DRILLING CONTRACTS

Oil and gas well drilling is generally carried out by independent drilling contractors. Because drilling contractors are specialists, they can normally drill more economically and efficiently than the oil and gas operator. Although there are many types of drilling contracts, three basic forms exist: footage rate, day rate, and turnkey. The type of contract to be used depends on the type of drilling to be done, the location of the well, and the environment expected to be encountered. In the early 1980s, demand for rigs exceeded supply, causing almost all contracts to be day rate. Although day rates are still common, footage contracts are the norm in some areas. On average, onshore U.S. drilling rig rental costs represent approximately 30 percent of total well costs. A typical day rate drilling contract is illustrated in Appendix 8 of this book.

FOOTAGE-RATE CONTRACTS

Under the usual footage-rate contract, the drilling contractor is paid a specified amount per foot of hole drilled. (There is no implication that it costs the same amount for each foot of hole drilled. Costs increase significantly as the depth of the well increases.) For example, in early 2000 approximate footage rates for three U.S. areas were:

- $8/ft for 7,000 foot wells in Colorado's Wattenberg field of tight sands gas wells,
- $8.50/ft for shallow wells in Appalachia, and
- $15 to $16/ft for 12,000 foot wells in the Permian Basin.[18]

The contract usually calls for drilling to a specified depth or to a

[18] Source of rates: Richard Mason, publisher of *Land Rig Newsletter*.

specified number of feet below a specific geological horizon, whichever comes first. The footage rate is determined by taking the total estimated costs to drill to that depth, adding a risk factor and profit, and then dividing the total by the targeted depth. The contractor furnishes the rig, the crew, services, and certain materials and supplies. The operator normally furnishes the well equipment and may provide the drilling mud. Certain activities are not included in the footage rate. For example, taking core samples, running various tests, and logging are usually treated as activities extraneous to drilling and are separately charged to the operator on a day-rate basis.

The drilling contract specifies the payment schedule for work performed. Payments under the drilling contract, including amounts owed for day work performed, may be required at specific time intervals or may be required when drilling has reached specific depths. The drilling contractor may require that a portion of the estimated total costs be prepaid. Except for factors outside the control of the drilling contractor, payment is usually contingent upon reaching the contract depth.

DAY-RATE CONTRACTS

The day-rate contract is conceptually simple. The drilling contractor is paid a specified amount for each day worked on the well, regardless of the number of feet drilled. The drilling contractor furnishes the rig and the crew. Unless the contract specifies otherwise, all materials, supplies, and other services are furnished by the operator. The method and manner of payment are stated in the contract. Usually the contract specifies two daily rates, one for time when the contractor is actually engaged in drilling and a lesser figure for *standby time*, during which the operator may be running tests or having other services performed.

The day-rate contract is used for virtually all offshore work. It is also used onshore in areas where geological conditions are not well known or the drilling and environmental conditions are considered hazardous.

Like footage rates, day rates vary, depending on the location and environment where the well is to be drilled. Day rates may also vary greatly over time with change in demand for rigs in the area. In onshore Texas operations, the average day rate in late 1999 approximated $6,800 per day for a 1,000 horsepower rig capable of drilling to 12,000 feet.

In late 1999, the Gulf Coast day rates for jackup rigs (150 to 300 feet of water) were volatile, approximating $24,000 per day in late November, up from $15,000 a month earlier. Rates for semisubmersible rigs in late 1999 included $35,000 per day for a rig rated for 2,000 foot water and $95,000 per day for a rig rated for 3,500 foot water. When one considers that the drilling of an offshore well may require over 100 days of drilling time, the magnitude of the total cost is readily apparent.

TURNKEY CONTRACTS

The turnkey contract has been in use for many years and originates from real property law in the United Kingdom. The basic feature of a turnkey contract is that the contractor performs specified services for a set price and the operator merely has to *turn the key* when the project is completed. For a specified sum, the drilling contractor performs all services and furnishes all materials required to complete the job. The operator has no liability until the contract requirements are met. Normally the turnkey contract specifies day rates for completion work.

There are advantages and disadvantages to the turnkey contract for both the contractor and the operator. This contract allows the contractor greater latitude in the way drilling is done and in the selection of the drilling mud and drill bits in order to drill the well in the most economical and efficient manner possible. The advantage to the operator is obvious: no matter what problems are encountered, the total cost of the well is the contract price.

The disadvantage for the drilling contractor is that the contractor must complete the well as specified regardless of the cost. Many things can happen in the drilling process to make the turnkey contract a costly risk to the contractor. The major disadvantage to the operator is that, because of unknown and unexpected drilling problems in wildcat areas, drilling contractors are usually reluctant to enter into a turnkey drilling contract in such areas. Because of the inherent risks of drilling and the need for the drilling contractor to charge for these risks, total costs will generally be higher under a turnkey arrangement than under other types of contracts.

OTHER ARRANGEMENTS

Other approaches may be used to arrive at the consideration for drilling and equipping a well. These arrangements usually represent modifications or combinations of the types of contracts discussed previously. One important method for compensating the driller or provider of other services is for the operator to transfer an operating or nonoperating interest in the lease to the driller or provider of services. For example, the drilling contractor may be given an overriding royalty interest in the drill spacing unit in return for providing drilling services and supplies.

THE DRILLING PROCESS

Two methods of drilling have been used in the U.S.: rotary-rig drilling and, many years ago, cable-tool drilling. The cable-tool method is one of the oldest mechanical means known for drilling into the earth's surface. Cable-tool rigs have long been used for drilling water wells and salt brine wells. A cable-tool rig was used in 1859 to drill the Drake well in Titusville, Pennsylvania; this innovation marked the beginning of the oil industry as we know it today. The rotary method came into significant use just prior to 1900, and rotary rigs are used to drill virtually all U.S. oil and gas wells today.

CABLE-TOOL DRILLING

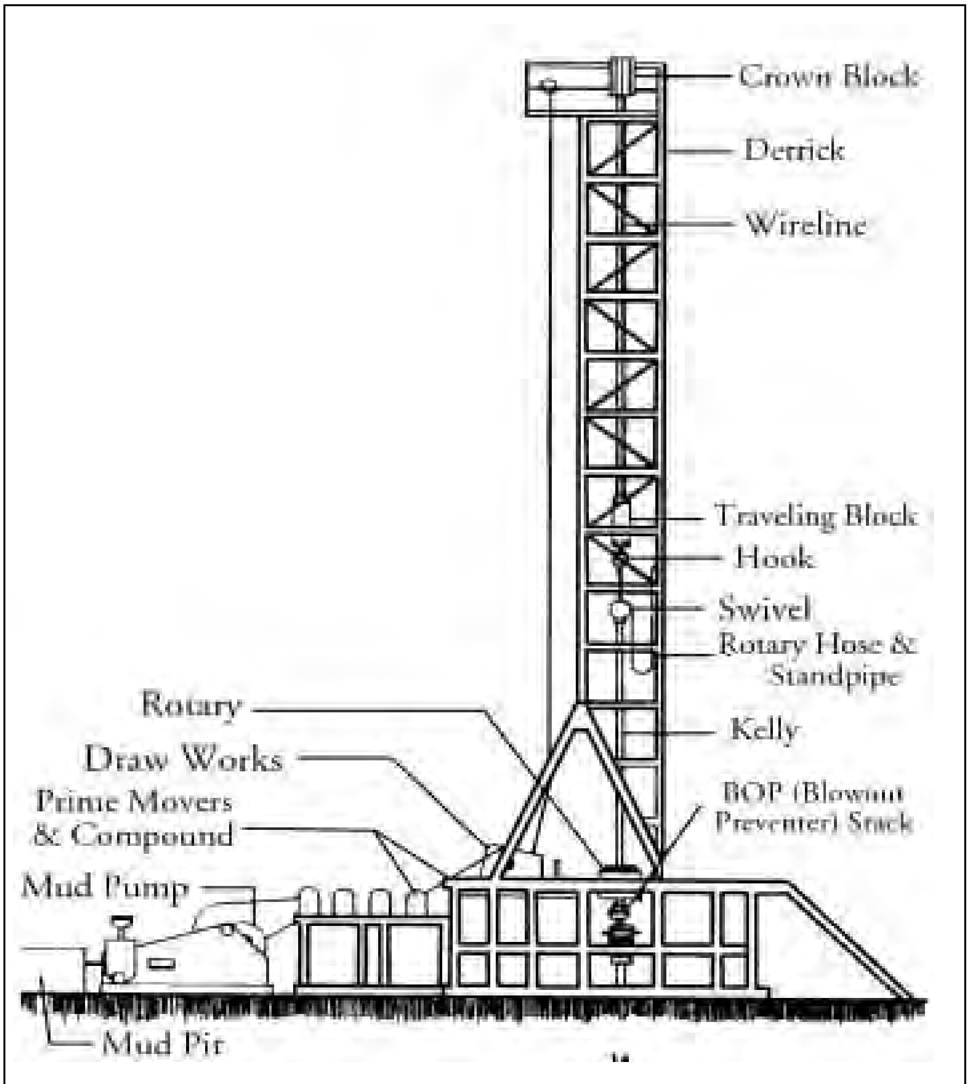
In the cable-tool method of drilling, a heavy piece of forged steel is lowered into the hole. The bit, which weighs several hundred pounds, is raised and then dropped in the hole, literally pounding a hole in the earth. Water is pumped into the hole to float the cuttings of rock away from the bottom of the hole. After drilling for a few feet, the bit is hoisted to the surface and removed; the bit is then replaced by a *bailer*, which is merely a length of pipe with a one-way valve at the bottom. With some raising and lowering of the bailer, formation chippings suspended in water are entrapped, raised back to the surface, and dumped. The bailer is then removed, and the drill bit is put back on and lowered back into the hole to pound through formation rock again.

The primary disadvantages of cable-tool drilling are that it is less than one-tenth as fast as a rotary rig and does not provide a means for controlling formation pressures. Uncontrolled pressure in underground formations may cause a *blow out* (or *blowout*) with oil or gas spewing upward out of the well, resulting in both economic waste and environmental damage.

ROTARY RIG DRILLING

Rotary drilling is by far the most widely used method of drilling for oil and gas today. In rotary operations, the hole is drilled by rotating a drill bit downward through the formations. The drill bit is attached to the bottom of the *drill string*, which consists of the bit, drill collars, drill pipe, and the *kelly*. *Drill collars*, attached between the bit and drill pipe, are heavy, thick-walled pipe that adds weight to the bottom of the drill string. The *kelly* is a hexagonal section of pipe that passes through a *rotary table* and is clamped to the table. Power is transmitted to turn the rotary table, which in turn rotates the kelly, the drill pipe, the drill collar(s), and the drill bit. As the drill bit rotates, it cuts or chips away pieces of the formation. The kelly, the drill pipe, the drill collars, and the drill bit are all hollow. As drilling progresses downward, additional sections of drill pipe are added to the string as needed. Drilling mud is circulated under pressure down through the drill string of pipe, out small holes in the drilling bit at the bottom of the hole, into the wellbore, and then up outside the string back to the surface, carrying with it the cuttings from the formation. Figure 8-2 illustrates the main components of a rotary rig.

Figure 8-2: Rotary Rig



In rotary drilling, operations normally continue around the requiring two or three drilling crews to maintain continuous operations The individual in charge of the rig is referred to as the *toolpusher* and has overall responsibility for the operations. Normally the toolpusher is on call 24 hours each day. A *driller* leads each crew. Crew members include a *derrick man* who works in the top of the rig when pipe is being placed into or being removed from the hole and two or more *roughnecks*, who work on the rig floor. A *motor man* may also be included in the crew to take care of the engines and power equipment, although this responsibility is sometimes given to the derrick man to perform while he is not working in the top of the rig. In onshore drilling it is normal for each crew to work an 8-hour shift (tower); but because of the logistics of offshore operations, the crews work 12 hours and are then off duty for 12 hours. Even when they are off duty offshore crews remain on the drilling platform for at least seven days and are then returned to shore for the same number of days. Since most drilling is now performed by independent drilling contractors, an engineer or geologist employed by the operator will also be present on location at all appropriate times.

The components of a typical onshore rig fall into five major groupings: the derrick or mast, the power system, hoisting equipment, the rotary system, and the mud system.

The Mast

The mast or derrick is the structure placed over the intended drilling location. The derrick floor houses much of the equipment needed for the drilling operation and serves as a base for the mast itself. For drilling shallow wells and for some workover operations, a self-contained rig mounted on a large truck may be used. In most onshore work, however, a *jackknife mast*, which consists of a series of modules that can be erected at the well site, is used. The derrick structure must be capable of withstanding great vertical stress. The drill string alone may weigh as much as 500,000 pounds when a deep well is drilled.

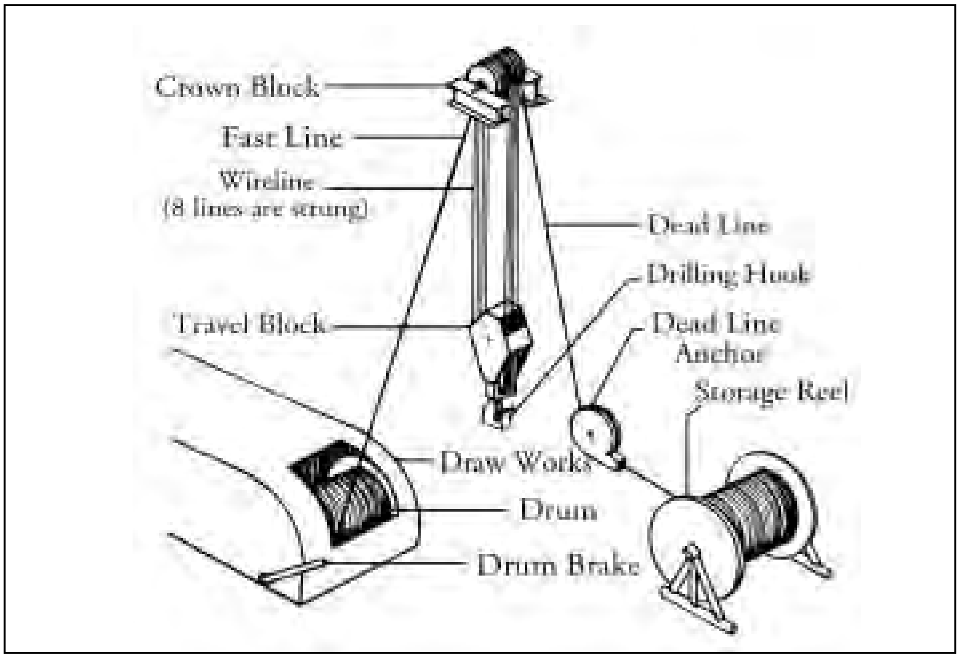
Power Supply System

The power system furnishes power for rotating the drill string and bit, hoisting operations, fluid circulation, compressed air, lighting, and other functions. Rigs capable of drilling only to shallow or moderate depths may require only 1,000 horsepower, while those capable of drilling over 20,000 feet may require more than 3,500 horsepower. Diesel, gasoline, diesel-electric, and other types of power sources are used.

Hoisting Equipment

The hoisting equipment must be able to bear heavy loads in supporting the drill string and moving strings into and out of the hole. An illustration of a hoisting system is shown in Figure 8-3.

Figure 8-3: Hoisting System

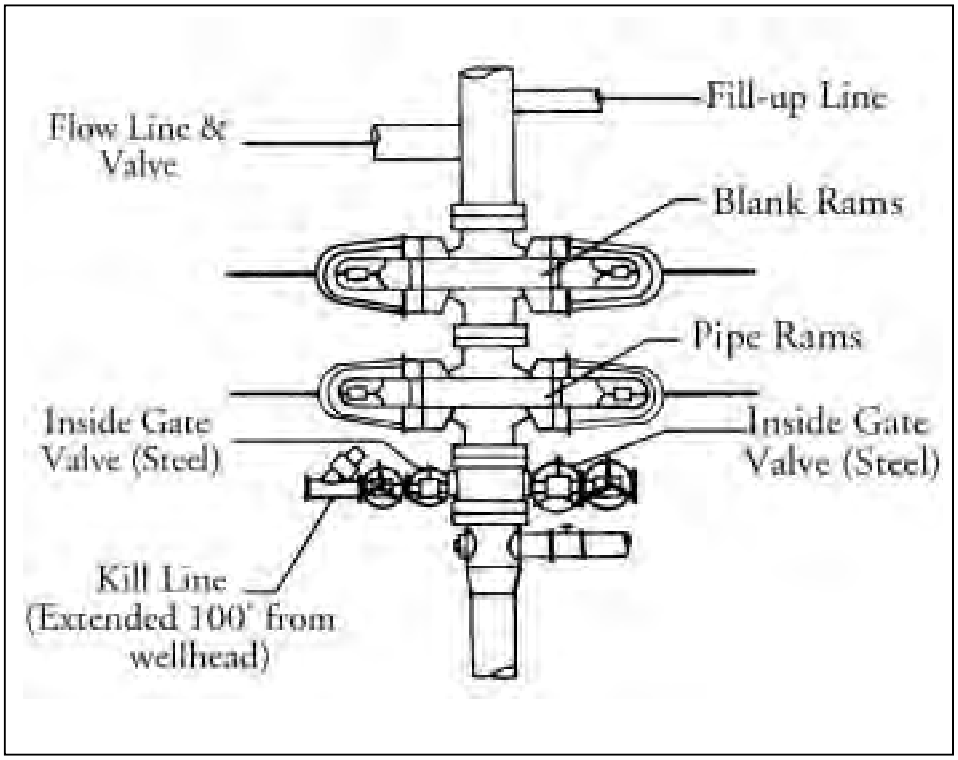


Rotary System

The rotary system begins with the *rotating swivel* at the top of the kelly and ends with the drill bit at the bottom of the hole. The swivel allows the entire system to rotate while being held by the hoisting system. Power is applied to the rotary table, and when the kelly bushing is engaged, the drill string, the collars, and the bit rotate so that the bit cuts into the formation.

While not actually part of the rotary system, very important parts of the drilling system are located under the rotary table. The *blowout preventers* are especially important. A blowout may occur when a formation containing gas, water, or oil is encountered if the formation pressure exceeds the pressure being maintained by the drilling fluid in the wellbore. To alleviate this danger, blowout preventers are used. These are two or more *stacks*, or large valve packages, capable of withstanding high pressures. One of these sets of valves is installed so that the well can be shut in while the drill string is in the hole, and the other is designed to be closed when the drill string is removed from the hole. Blowout preventers usually have two sets of controls, one located on the rig floor and the second located at a remote location. The placement of the blowout preventer stacks is shown in Figure 8-4.

Figure 8-4: Placement of Blowout Preventer Stacks



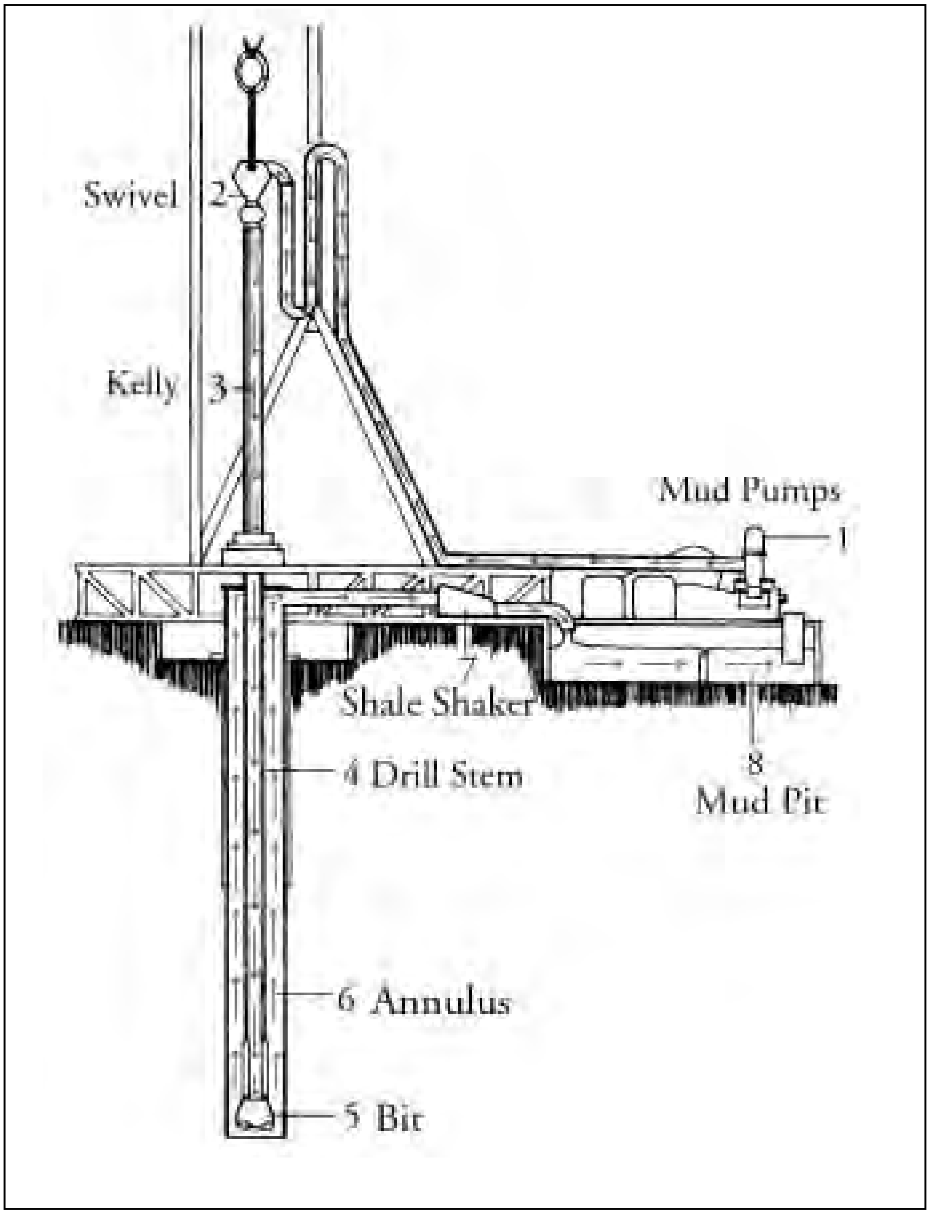
The Mud System

In rotary drilling, the fluid, or drilling mud, plays several important roles. The circulating drilling mud suspends and brings to the surface the cuttings of the formation being drilled through. These cuttings are analyzed to identify the formation and to determine the absence or presence of hydrocarbons. The drilling mud also lubricates and cools the drill bit and coats the wall of the well, sealing off the formations and making the well wall more stable. The weight of the drilling mud also helps in preventing blowouts caused by high pressures in the formation being drilled through. The fluid mixture and specific gravity are constantly monitored to provide optimal drilling conditions and control of the well. The mixture of materials used in the fluid determines the weight of the fluid column.

To achieve these objectives, many types of drilling muds are used. A commonly used mud is merely a mixture of clay and water. Various chemicals may be added or substituted for the clay, depending on the conditions encountered. The mineral barite is used to add weight to the drilling fluid; it is about 4.2 times as heavy as water. Certain types of formations could be damaged by water; in those formations an oil base is used for the drilling fluid. Even in drilling a single well, several changes in the drilling fluid may be made.

Figure 8-5 shows the path taken by the drilling fluid in circulating through the well. From the mud pumps (1) the fluid goes through the discharge line to the swivel (2), from the swivel down through the kelly (3), and through the drill pipe (4) to the bit (5). At the bit the drilling fluid washes the cuttings from the bit and the bottom of the hole and carries them back to the surface through the annulus (6). At the surface a pipe carries the cuttings in suspension through a shale shaker (7), which removes cuttings from the drilling fluid. From the shaker the drilling fluid goes to the mud pit (8) and the whole cycle starts again.

Figure 8-5: The Mud System of a Rotary Rig



DRILLING OPERATIONS

Many operational aspects of drilling have been mentioned above in the discussion of drilling rig components. Certain other aspects of drilling also need to be considered.

Directional and Horizontal Drilling

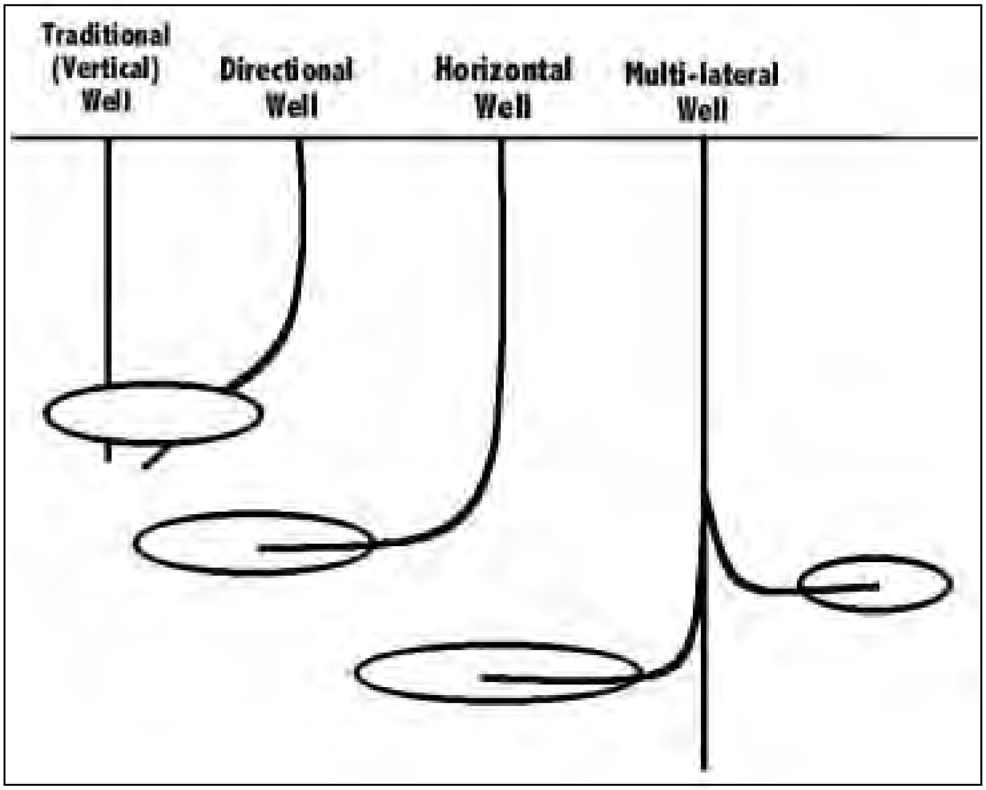
In the early days of the industry, wells drilled with cable tool equipment were assumed to be vertical. With the advent of rotary drilling, it was discovered that it is almost impossible to drill a truly vertical well. Changes in the angles of the rock formation layers, known as dip angles, differing rock strength, and drilling practices cause the drill bit to drift away from true vertical. Drillers later learned how to purposely drill in a certain direction, allowing them to access areas where the surface location didn't allow a rig to be set up, such as offshore Huntington Beach, California, and under the state capitol building in Oklahoma City, Oklahoma.

When offshore platforms were set in the Gulf of Mexico, even more emphasis was placed on *directional drilling*. The wells on a typical offshore platform go out in all directions, allowing each platform to drain a much greater area than would be possible with one well. The distance away from the platform that a directional well can *reach* depends on many factors, particularly the depth of the target formation, but a reach of one mile is not uncommon.

In a vertical well, the wellbore bisects the formation approximately at a right angle, resulting in a minimum of formation *section* being exposed to the wellbore (Figure 8-6). One of the main factors governing the rate of oil or gas flow into the wellbore is the length of section exposed to the wellbore. The industry has long recognized that if this section could be lengthened by drilling horizontally along the strata in the formation, production rates and ultimate reserves would be greatly increased. Advances in areas such as downhole rotating motors and bits, metallurgy, downhole gyroscopic steering tools, mud systems, and logging tools have made horizontal drilling a technical and economic reality.

A typical horizontal well starts out much the same as a vertical well. At some predetermined point above the target formation, the *kickoff point*, a special directional drillstring is run to start the turn from vertical to horizontal. The radius of the curve between vertical and horizontal depends on many factors but can be from a few feet to several hundred feet, depending on the design of the tools and the requirements of the situation. In a typical well, the wellbore path is designed to be horizontal at the time the target formation is encountered, and the wellbore is continued so that it remains within the target formation during the horizontal segment (Figure 8-6).

Figure 8-6: Vertical, Directional, and Horizontal Wells



The horizontal segment can extend a considerable distance. There are many wells with over one mile of horizontal section, and the limits are continually being extended. Although many advances have been made regarding problems with transmitting the necessary force to the drillbit, overcoming friction in pushing and pulling pipe and tools through the horizontal section, and keeping the heavy drill cuttings from settling out of the mud in the horizontal section, these factors will ultimately limit the distance that horizontal wells can reach. Recent technology has allowed multiple horizontal segments from the same vertical wellbore to radiate out in different directions, either in the same formation or at different levels in different formations. Such wells are called multi-lateral wells, and resemble the trunk and main branches of an upside-down tree. Hence, the vertical well shaft is called the trunk of the multi-lateral well.

Initially, horizontal wells were very expensive compared with vertical wells, by a factor of several times the cost to drill a vertical well. Experience and technological advances have brought the average cost down to about twice the vertical well cost. Improved production rates more than offset the higher costs. Multi-lateral wells may be less costly than drilling several vertical wells. Horizontal wells are not applicable everywhere; thick, fractured formations with limited horizontal permeability, such as the Austin Chalk formation prevalent in south central Texas, are the ideal candidates with oil zones generally being more economically feasible than gas zones. However, horizontal drilling has also been used in areas where environmental constraints restrict surface access, for minimizing undesirable gas or water coning, and to improve sweep efficiency in waterfloods and some tertiary projects.

Even though directional wells can reach as far as horizontal wells, they are still designed to go through the target formation at a relatively small angle rather than horizontally along it. Therefore, directional wells do not expose much more formation than a vertical well.

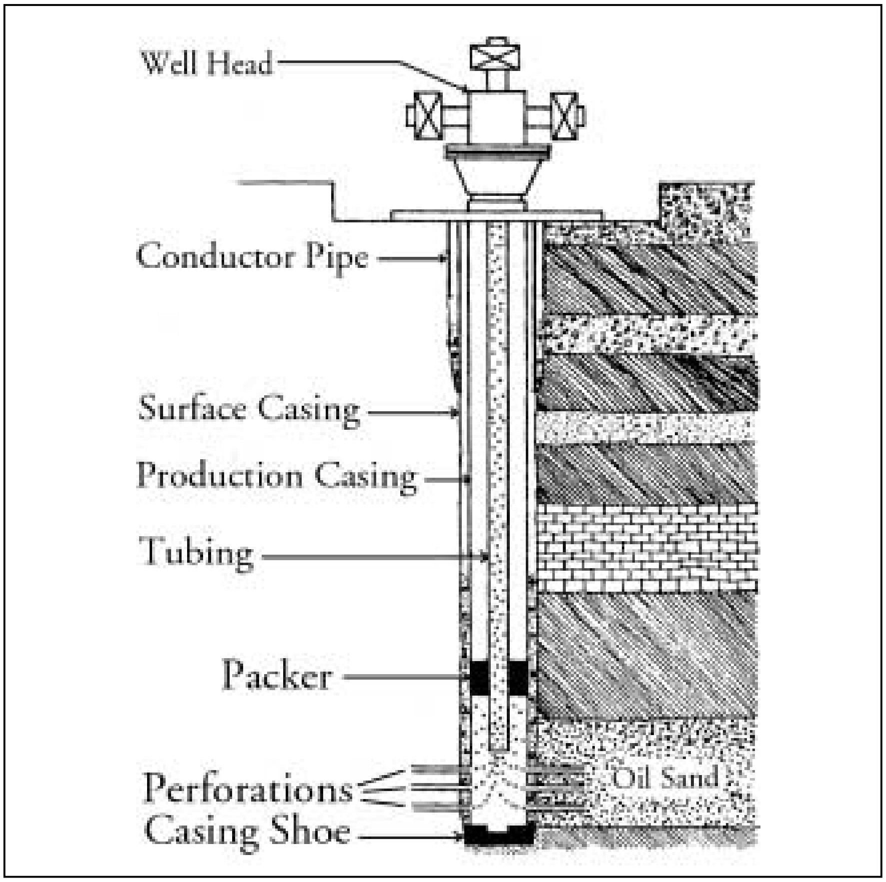
Well Site Preparation

After exploration work has been completed and the leases obtained, preparation for the actual drilling is begun. Completion of the geological work to locate the well site and to stake the well mark the commencement of drilling operations. Access to the location must be secured, and building roads and bridges may be necessary. The well location must be graded, mudpits dug, and the rig and other components moved to the well site.

Drilling

After the location is prepared and the rig is on location, the crew is ready for *spudding-in* (the commencement of drilling operations). An auger bit may be used for the initial drilling if the surface is soft; otherwise, a regular rotary bit may be used. The initial section of the hole is relatively large to permit the installation of casing that may be required by the drilling plan. Large conductor casing (often 20 inches in diameter) may be installed for a few feet at the surface to prevent caving in of the hole. Surface casing (perhaps 13 3/8 inches in diameter) will be installed and cemented to a point below all fresh water formations in order to prevent contamination of these formations. Additional strings of casing will be installed as needed. The various types of casing and pipe that are typically used in a well are shown in Figure 8-7.

Figure 8-7: Casing & Pipe in a Typical Well



Although drilling progresses rapidly near the surface, continuous attention is given to the drilling mud indicators, to the cuttings brought up from the bottom of the hole, and to the drilling speed. These observations give some indication of the condition of the drill bit. More importantly, they indicate the type of formations being drilled. When there are indications that the formation has changed significantly, or the drill bit has become worn and is not effective, the bit must be changed.

Depending on the formations being drilled and the type of bit used, a bit may last for only a few feet or for several hundred feet.

As the hole is drilled, additional pieces of drill pipe in 30-foot lengths are added to the string. When it is necessary to change the drill bit, all of the drill pipe must be removed from the hole, the old bit removed, the new bit attached, and all the drill pipe reinserted in the hole. This process is referred to as making a *trip* (*tripping-out* and *tripping-in*). The entire process is called making a *round trip.* In making a round trip, the drill string is disconnected and reconnected in *stands*, consisting of one, two, or three 30-foot sections of drill pipe, depending on the size of the rig. Because a round trip at a depth of 14,000 feet requires approximately seven hours, a considerable amount of time is spent merely changing bits during the drilling of a well.

Throughout the drilling process, different types of tests are performed. The drilling fluid is examined, pressures are watched, and cuttings from the well are sampled and examined with special instruments. Additional tests are run when appropriate in order to gain technical knowledge about the formations and their properties, including the possibility that the formations contain sufficient hydrocarbons to justify completion of the well.

When the cuttings indicate the presence of hydrocarbons, further information must be obtained. A larger sample may be taken from the formation by *coring*. The drill string is taken out of the hole, and in place of the drill bit a *core barrel* is attached; the drill string is then lowered back into the hole. The core barrel is a specially designed bit that has a hole in its center. The size of the core will vary, depending on the instrument used, but will be from about one inch to slightly over four inches in diameter. The core barrel permits the capture of the sample which is then brought back to the surface for evaluation. These cores are evaluated for such reservoir characteristics as porosity, permeability, saturation, and fluid content.

Additional information can be gained about a potential formation by running a *drill-stem test*. This test is essentially a temporary completion of the well. A *packer* is inserted into the hole and expanded to seal off the drilling mud from the formation being tested. The formation fluids are then allowed to flow upward through the drill string, and data about the fluid content, formation pressure, and other factors are gathered.

Certain tests, referred to as *well logging*, may be run at virtually any point during the drilling but are usually carried out when the approximate target is reached. The most common logging methods used are *electric logging* and *radioactive logging*. Each formation and each fluid responds differently to the tests made by the logging instruments. Proper interpretation of the well logs will indicate the type of formation and the fluids present at various depths.

The primary objective of the tests performed during drilling is to determine whether the well has the potential for being economically productive. The tests provide information at all depths to help the geologists decide whether to attempt completion of the well, to plug and abandon the hole, or to continue drilling.

Problems Encountered in Drilling

One potential problem that may be encountered in drilling is a high-pressure blowout, which has been referred to previously. If a blowout occurs, there is an economic and environmental loss. The well must be brought under control, even if it requires *killing* the well.

Losing equipment in the hole is another hazard often encountered. Part of the drill string may be twisted off and must be retrieved before drilling can continue. The driller must attempt to remove the obstruction by *fishing* for the pipe or other equipment that is loose in the hole. If the material cannot be retrieved, the hole may be *sidetracked* around the lost pipe if possible. In some cases the only solution is to move the rig and start a new hole (a *twin well*).

The drill pipe may also become stuck in the hole. A collapsed portion or sharp bends in the hole can cause stuck pipe. If the drill string cannot be removed, the only alternative is to cut off the string at the stuck point and proceed in the same way as when pipe is lost in the hole.

While drill pipe in 30-foot sections appears to be rigid, it becomes quite flexible when several joints of pipe are on a string. Deviations from a true vertical axis are normal, but the deviations must be controlled so that the hole is not drilled in an unacceptable direction.

Another problem encountered is *lost circulation* of the mud. This problem occurs when the drill bit breaks through into a cavern or into a formation having very large fissures or fractures; the mud then escapes into the formation. In this event the formation must be plugged up with cement and/or casing before drilling can continue.

Many other problems may be encountered in drilling a well, but the problems described above are common. In every case unexpected (but not unusual) problems can drastically increase the costs originally anticipated for drilling the well.

COMPLETING THE WELL

After drilling the well to final depth and evaluating the many tests that have been made during drilling, the operator is faced with the decision to abandon the well or to attempt completion. There is no fine line of demarcation that gives an automatic answer to the question of whether to abandon or to attempt to complete the well. The answer depends on whether the operator thinks there are enough hydrocarbons present to economically justify the additional expenditures necessary to complete, equip, and produce the well.

DRY HOLES

If, in the opinion of the operator, there are no reserves or if there is an insufficient quantity of reserves to justify completion, the well will be plugged and abandoned (P&A'd). If possible, equipment in the hole will be salvaged and either sold or returned to the warehouse if suitable for future use on another project. However, very little of the equipment installed in the hole, such as casing, can be salvaged, because of either physical reasons or regulatory requirements. Because of potentially high formation pressures or other factors, the entire casing string in some areas must be encased in cement; thus, no casing can be removed. In any event, the surface casing usually cannot be removed because almost all governmental regulatory bodies require that it be left cemented in the hole and a cement plug installed at the surface.

WELL COMPLETION

The operator may think there is enough evidence that the well can be completed as an oil well or gas well to justify the additional costs of completion. Completion of the well does not necessarily mean that the well will be profitable. Many wells are completed that will never recover all drilling, completion, and production costs. A well will be completed if anticipated revenues from production are expected to significantly exceed the anticipated completion and production costs. Therefore, even if the overall operation is not profitable, in the sense that all costs (including drilling costs) will not be recovered, completion of a well may be economically justified.

In completing the well, production casing is set and cemented into the hole, perhaps cemented only at the bottom of the well and at the surface. The casing and cement close off the formation. On the basis of well logs and other analyses, the potential hydrocarbon-bearing formation or formations will have been identified. Perforations in the casing must now be made to permit fluids from the formation to flow into the well bore. A perforating gun is lowered into the hole by means of a wire line. At the proper depth, the gun is fired and perforations are made through the casing and into the formation. Perforations may be made by firing projectiles through the casing and the cement or by using a jet or rocket charge that burns its way into the formation. Other techniques are also being developed for perforating casing. No matter which process is used, the purpose is to create a hole to allow the hydrocarbons to flow through the cement and casing into the well bore for flowing to the surface.

In some cases permeability of the formation is low and the oil or gas cannot flow from the formation into the well, so steps must be taken to increase permeability. Two methods used to increase permeability are *fracturing* and *acidizing*. The usual process in sandstone is fracturing. Coarse sand or synthetic beads, called the *proppant*, is mixed in a fluid and pumped down the well bore, through the perforations, and out into the formation under very high pressures.

This causes the formation to split or fracture. When the pressure is released, the fluid comes back into the well bore; the coarse sand grains continue to prop open the fractures and allow the hydrocarbons to flow into the well bore with greater ease. If the formation is a calcium carbonate material, the pumping of acid through the perforations (acidizing) will dissolve portions of the formation, creating channels through which the formation contents can flow.

If there is fluid (usually drilling mud) in the well and the pressure of the reservoir is low, it may be necessary to *swab* the well to remove the fluid. Swabbing is a relatively simple process. A small expandable packer is lowered into the well, and by swiftly pulling the packer back out of the hole the fluid is removed.

EQUIPMENT REQUIRED TO COMPLETE A WELL

The equipment used in completing a producing well depends in part on whether the well produces oil, gas, or both. Additionally, the equipment required depends on whether the well is flowing or being produced by some form of *artificial lift*. In either case, tubing and casing will have to be run into the well and the wellhead connections attached in order to control production.

As previously discussed, surface casing will be cemented through all fresh water formations to prevent contamination of these formations and to prevent cave-ins. A second string of casing, called the *intermediate string*, may also be required to control and seal off deeper formations. The production string is then generally run from the surface to or through the producing formation. Unless high pressures are involved, each of these strings will be cemented at its bottom. Oil and gas could be produced through casing, but a string (or strings) of *production tubing* through which the oil or gas will be brought to the surface is normally run into the well but not cemented. If repairs are later required, it is much easier to remove the production tubing than the casing.

Multiple completions in which two or more formations are produced through the same well are common. The procedures for preparing each formation for production are identical to those used for single completions. Cement and/or packers will generally be used above and below each of the producing formations so that the producing formations are sealed off to produce into the production strings. An illustration of a triple completion is shown in Figure 8-8. Valves and piping are attached at the surface to the well to form the *wellhead*, frequently referred to as the *Christmas tree*. The exact nature of the valves and piping depends on whether the well is flowing or if the product must be brought to the surface by artificial lift. A Christmas tree, used when the well is flowing from its own reservoir pressure, is shown in Figure 8-9. The Christmas tree for a well being produced by pumping is shown in Figure 8-10. Various gauges and meters are attached to the Christmas tree to measure the pressure and the flow of liquids.

Figure 8-8: A Triple-Completion in a Single Well

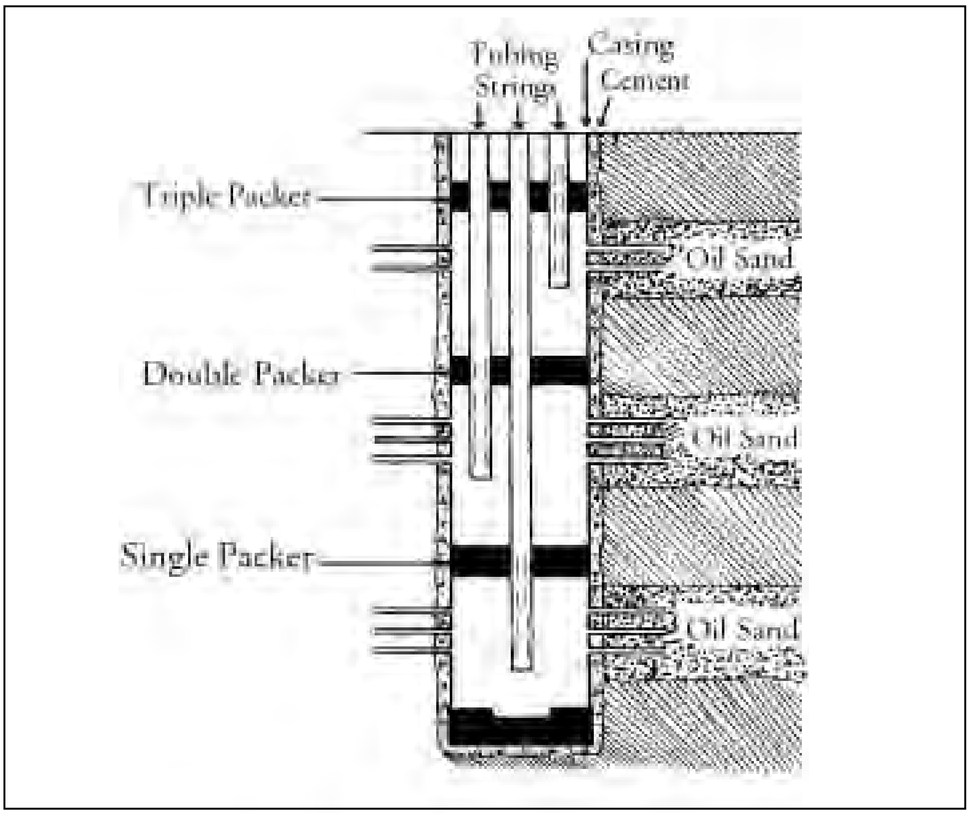


Figure 8-9: A Christmas Tree Valve to Control Production in a Flowing Well

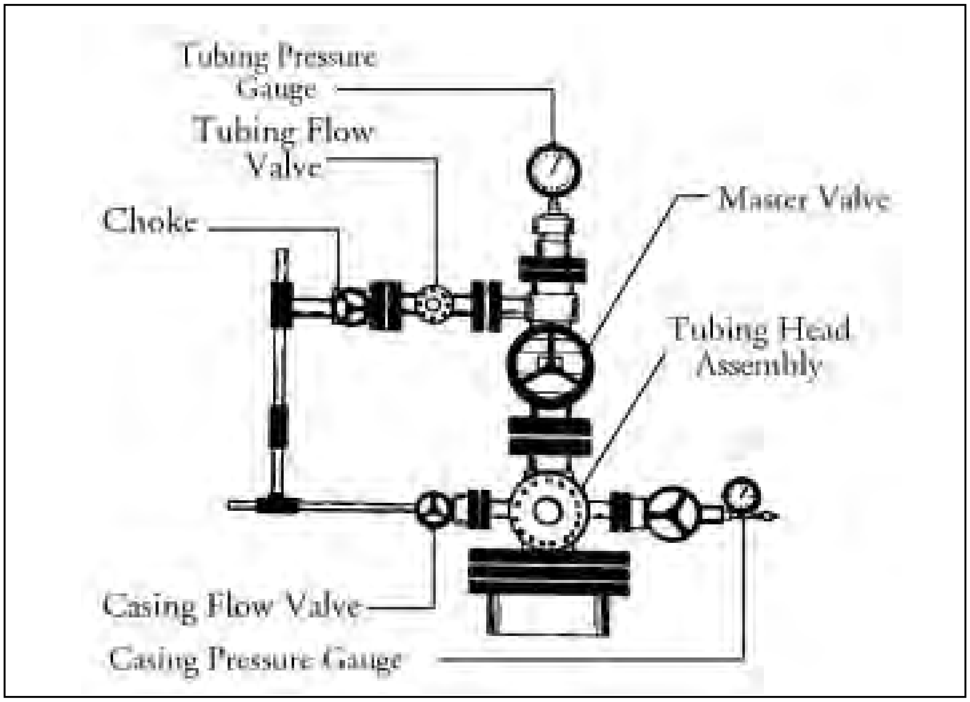
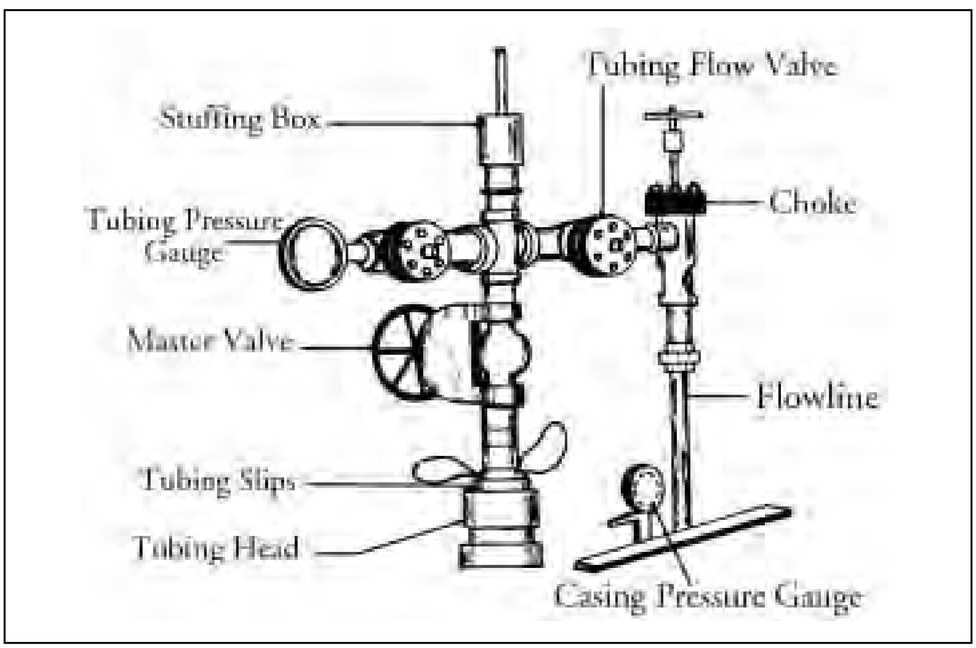


Figure 8-10: A Christmas Tree on a Well Being Produced by Pumping



If the formation is not capable of flowing as the result of formation pressure, some form of artificial lift or pumping unit must be employed. The most common form of pumping unit is the *walking beam unit*, depicted in Figure 8-11. The sucker rods are attached to the beam unit at the surface. Through the up-and-down movement of the beam unit, they actuate a simple lift pump located at the formation being produced.

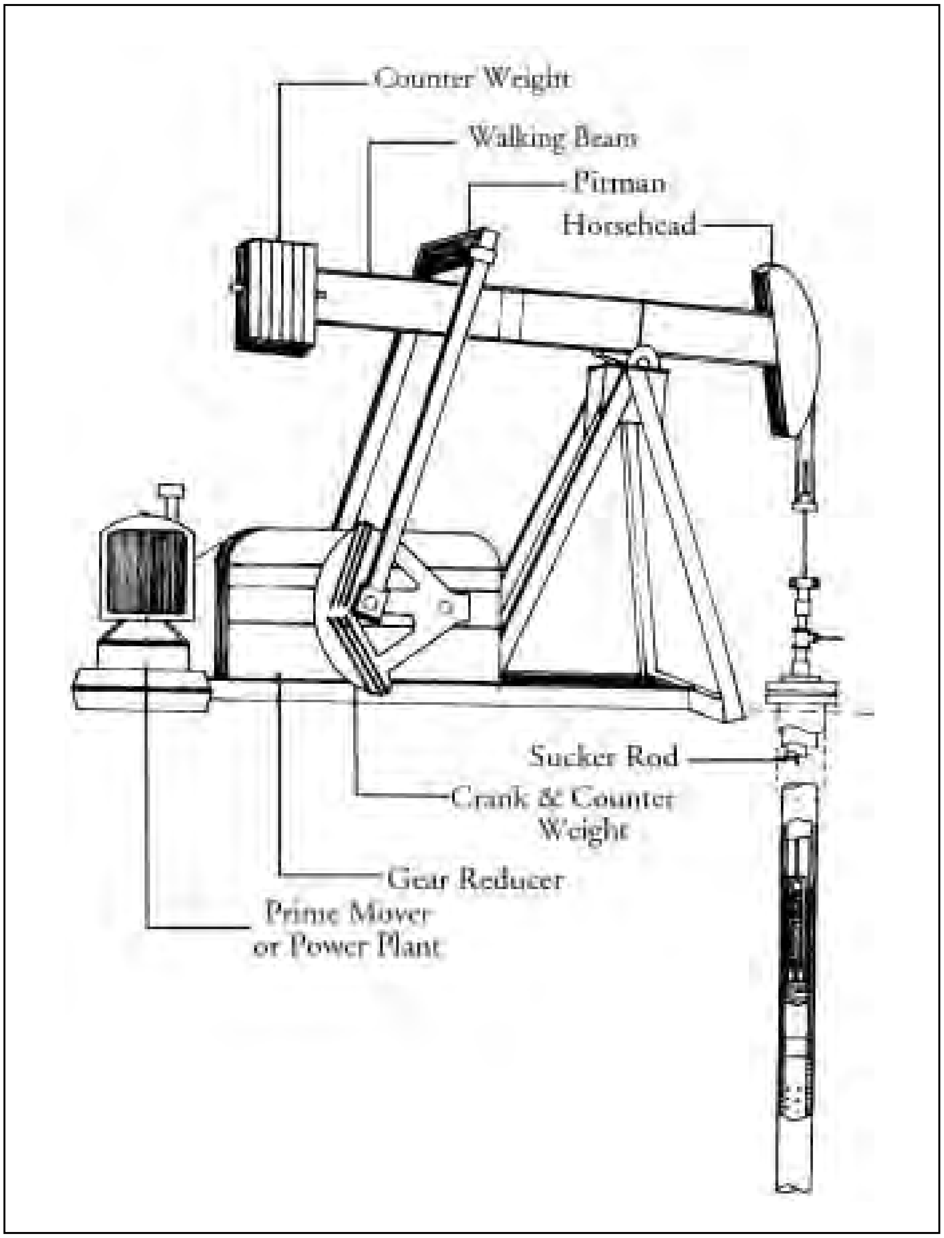
Getting the hydrocarbons to the surface is only one of the operations necessary for producing oil and gas. Other types of equipment are required on the lease, depending on whether the well produces oil and/or gas and on the amount of treatment required to process the output to prepare it for sale or use. This treatment is not a manufacturing process but rather involves the removal of impurities.

If an oil well is classified as oil only, the well produces no gas or only insignificant quantities of gas associated with the oil. When oil is predominant but a significant quantity of gas is present, the classification is an oil/casinghead gas well.

Casinghead gas (also called *dissolved gas* or *solution gas*) is dissolved in the reservoir's crude oil but bubbles out at the surface at normal atmospheric pressure. Gas in the gas cap overlying the oil is called *associated gas*. A gas reservoir with little or no oil is said to produce *nonassociated gas*. These terms are explained further in the Glossary.

To be classified as gas only, production from the well must have only insignificant amounts of liquid present. A gas/condensate well produces both natural gas and condensate. In the reservoir the gas and liquids are part of homogeneous hydrocarbons. When the gas is withdrawn from the reservoir and the pressure drops sufficiently, the lighter fluid fractions condense as discussed in Chapter One.

Figure 8-11: A Walking Beam Artificial Lift Installation



DEVELOPMENT OF THE RESERVOIR

Normally a single well does not constitute complete development of a reservoir. As discussed previously, even though additional wells may not significantly affect the quantity of hydrocarbons ultimately recovered, the number of wells definitely has an effect on the rate of extraction of the minerals and thus the *present value* of the income stream.

The amount of development of a reservoir is contingent on various factors. Even though the existence of production has been established through the drilling of the discovery well, the property may or may not have sufficient potential reserves to warrant the further expenditures required for complete development. The volumetric estimates of hydrocarbons in place can be prepared on an initial basis when the first well is completed. However, the samples are quite small. If a 4-1/2 inch core (a rather large core) is taken in a 40-acre spacing tract, the sample size is only one in over 13,000,000. Yet this sample, along with pressure tests, flow tests and rates, fluid analyses, and geological data, will be used in making the decision to continue with development. In spite of significant advances in technology, drilling provides the only final answer concerning the existence of hydrocarbons. Assuming that a successful well has been drilled, drilling and development will continue until the boundaries of the reservoir are delineated by dry holes or marginally economic wells on the periphery of the reservoir. Figure 8-12 illustrates the development process for a simple anticlinal structure.

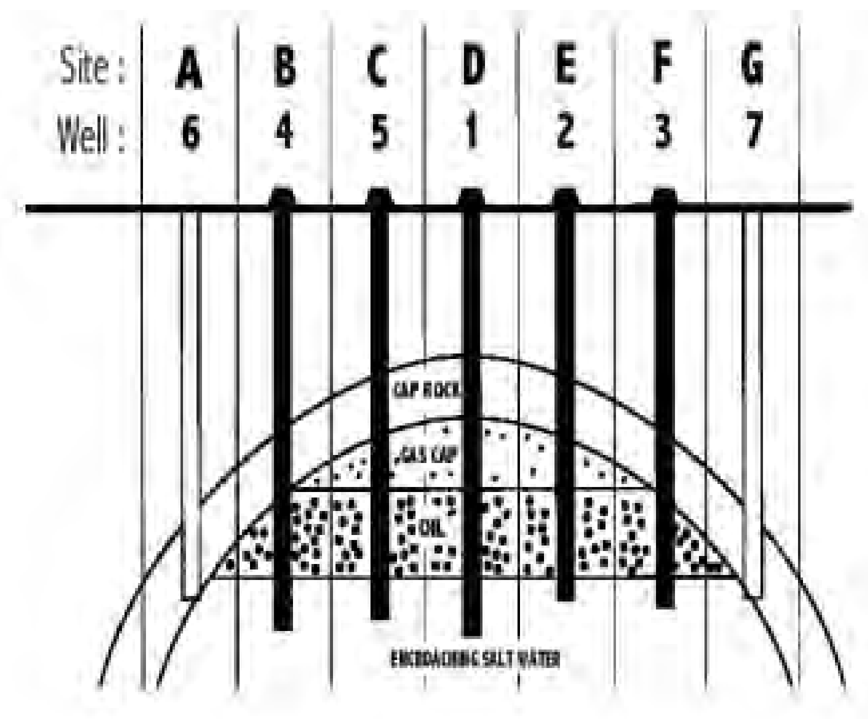
PLACING WELLS ON PRODUCTION

Various types of surface equipment are required to place the wells on production by collecting and gathering the production, treating the oil and gas to make them marketable, briefly storing the produced oil, measuring the volumes produced and the volumes sold, and removing the oil and gas from the lease. This process and the associated equipment are described in Chapter Eleven.

Figure 8-12: Reservoir Development

Site	Well	
D	1	Discovery, exploratory well establishes offset sites C and E as proved.*
E	2	Offset, development, producing well. Well 2 proves Site F.*
F	3	Offset, development producing well. Assume data does not prove Site G.*
B	4	Step-out, exploratory producing well on an unproved drill site. Assume data proves Site A.
C	5	Offset, development, producing well.
A	6	Offset, development dry hole. Costs remain capitalized as development costs. Well is plugged.
G	7	Offset, exploratory dry hole. Costs are expensed. Well is plugged.

*Proving a site means that geological and engineering data indicate with reasonable certainty that the site has sufficient reserves to economically justify (at current prices) drilling the site. Usually a successful well and G&G data prove only sites offsetting the successful well's site (as further discussed in Chapter Sixteen). The data may or may not prove all offset locations. See pages 208 to 211 and see the Glossary for definitions of discovery well, offset well, and step-out well.



WELL COSTS

The cost to drill and equip a well varies by such factors as the depth of the well, its general location, and industry economics that drive demand for drilling rigs in the immediate area of the well site. Figure 8-13 provides some general statistics on how much a well costs.

Figure 8-13: Costs to Drill and Equip U.S. Wells

For 1998	#of Wells Drilled	Per Well Averages Depth (feet)	Per Well Averages Cost ($)	Average Cost /foot
U.S. Total	22,590	5,825	$778,480	$133.64
Offshore (ex sidetrack wells)	747	11,187	$7,314,254	$653.66
Offshore, sidetrack wells	287	4,259	2,506,669	588.57
Onshore (ex sidetracks)	20,846	5,776	$635,000	$92.53
Onshore, sidetrack wells	710	2,260	366,524	162.18
Exploratory	2,364	7,043	$1,159,450	$164.62
Development	19,229	5,830	721,059	123.67
Oil Wells	7,322	5,014	$577,700	$115.22
Gas Wells	10,686	6,292	822,005	130.63
Dry Holes	4,582	6,032	997,818	165.43
Wells (ex sidetracks) by state:				
Texas	7,204	7,286	$741,174	$101.73
California	2,075	2,420	227,493	93.99
Appalachia	2,014	4,236	155,014	36.59
Oklahoma	1,781	6,872	547,088	79.61
Louisiana	1,516	9,405	3,422,732	363.92
Wyoming	1,212	5,745	588,586	102.45
New Mexico	1,074	6,769	537,191	79.36
Kansas	872	4,976	210,823	42.37
Colorado	706	4,826	314,220	65.11
Kentucky	480	2,595	102,417	39.47
Alaska	130	10,011	3,109,685	310.63
(Others,< 450 wells/state)				
Onshore (ex sidetrack wells) by depth (feet):	# as %			
<5,000	49%	2,571	$145,796	$56.70
5,000-9,999	35	7,250	493,241	68.03
10,000-14,999	13	11,789	1,419,389	120.40
15,000-19,999	2	16,770	4,180,657	249.30
20,000 & over	0.1	21,529	8,181,056	380.01

Figure 8-13 primary source: API's *Joint Association Survey on Drilling Costs* (November 1999)

Chapter Nine

ACCOUNTING FOR COSTS INCURRED IN DRILLING AND EQUIPPING OIL AND GAS PROPERTIES

Successful efforts accounting for drilling and equipping wells may be summarized as follows:

> Exploratory drilling costs are deferred until the outcome of the well is known. If an exploratory well finds proved reserves, the deferred costs are transferred to the company's Wells and Related Equipment and Facilities accounts. If the exploratory well does not find proved reserves, all deferred costs, net of salvage, of the well are charged to expense. *All* costs of wells drilled to develop *proved* reserves, along with all costs of equipment necessary to produce and handle the hydrocarbons, are capitalized (even if a development well proves dry).

Under full costing all drilling and equipment costs are normally capitalized and become part of the *cost pool* at the time they are incurred.

For income tax accounting, well costs are categorized as either intangible or tangible. The distinction is irrelevant for financial accounting but very important for income tax accounting and is often reflected in a company's Chart of Accounts. For determining taxable income, intangible drilling and development costs (IDC) are generally expensed as incurred, but tangible costs are capitalized and depreciated, as explained more fully in Chapter Twenty-Six.

SUCCESSFUL EFFORTS ACCOUNTING FOR EXPLORATORY WELL COSTS

Under Oi5, the drilling of exploratory wells is considered to be an exploration activity. Under successful efforts, exploration costs generally are expensed as incurred. However, the costs of an exploratory well in progress are capitalized. If the well finds proved reserves, the costs remain capitalized, subject to amortization, but if the well is a dry hole, the capitalized costs are written off. A more detailed discussion of the classification of reserves as *proved* may be found in Chapter Sixteen.

INITIAL RECORDING OF DRILLING IN PROGRESS

Oi5.110 specifies that costs of drilling an exploratory well are to be deferred until the outcome of the drilling is known:

> The costs of drilling exploratory wells and the costs of drilling exploratory-type stratigraphic test wells shall be capitalized as part of the reporting entity's uncompleted wells, equipment, and facilities pending determination of whether the well has found proved reserves.

Using the Chart of Accounts of Our Oil Company in Appendix 5, intangible drilling costs incurred on an exploratory well are charged to Account 241, *Work in Progress—Intangible Costs*, while the costs of tangible assets, such as casing, installed in an exploratory well are charged to Account 243, *Work in Progress—Tangible Costs*. (Many companies use only one general ledger account for Work in Progress, with separate subsidiary ledger accounts for intangible and tangible cost categories.)

For example, assume that Our Oil Company receives a statement for $98,000 from a drilling contractor for work performed on the first well on the Dorothy DiTirro lease. The effects on the general ledger accounts are shown by the entry below. (Subsidiary accounts and ledgers involved are discussed later in this chapter.)

241 Work in Progress—Intangible Costs	98,000	
301 Vouchers Payable		98,000
To record drilling costs on the DiTirro #1 well.		

In Our Oil Company, the costs of equipment, such as casing, installed in an exploratory well are accumulated in Account 243, *Work in Progress—Tangible Costs*. Thus, if an invoice for $45,000 for casing used in the exploratory well is received and vouched, the costs would be recorded as follows:

243 Work in Progress—Tangible Costs	45,000	
301 Vouchers Payable		45,000
To record cost of casing installed in the DiTirro #1 well.		

RECORDING OUTCOME OF EXPLORATORY WELLS

Oi5.110 requires that when the successful efforts method is used, the accumulated costs of an exploratory well shall be disposed of as follows:

> If the well has found proved reserves (refer to paragraphs .122 through .125), the capitalized costs of drilling the well shall become part of the enterprise's wells and related equipment and facilities (even though the well may not be completed as a producing well); if, however, the well has not found proved reserves, the capitalized costs of drilling the well, net of any salvage, shall be charged to expense.

When a well finds proved reserves, the appropriate accumulated costs are removed from the Work in Progress accounts and are charged to accounts and subaccounts for Proved Property Well and Development Costs:

231	Intangible Costs of Wells and Development	98,000	
233	Tangible Costs of Wells and Development	45,000	
	241 Work in Progress—Intangible Costs		98,000
	243 Work in Progress—Tangible Costs		45,000

To reclassify the costs of the successful DiTirro #1 well.

When an exploratory well is determined to be dry in Our Oil Company, the accumulated costs, less salvage value, applicable to the well are charged to Account 804, *Unsuccessful Exploratory Wells*, and removed from *Work in Progress—Intangible Costs* and from *Work in Progress—Tangible Costs*, as shown in the following entry for a second exploratory well on the DiTirro lease:

804.001	Unsuccessful Expl. Wells—Intangibles	100,000	
804.002	Unsuccessful Expl. Wells—Tangibles	40,000	
	241 Work in Progress—Intangible Costs		100,000
	243 Work in Progress—Tangible Costs		40,000

To expense costs of the unsuccessful DiTirro #2 exploratory well.

If any of the tangible equipment is removed from the hole and saved, the net salvage proceeds or net salvage value will be credited to the *Unsuccessful Exploratory Wells—Tangibles* account.

A major accounting problem facing companies using the successful efforts method is determining how long to defer costs applicable to an exploratory well that has been drilled but whose outcome is not ascertained. This problem is examined later in this chapter.

POST-BALANCE-SHEET EVENTS

Oi5.130 provides that post-balance-sheet events should be considered in determining the proper disposition of costs accumulated on exploratory wells in progress at the balance sheet date.

> Information that becomes available after the end of the period covered by the financial statements but before those financial statements are issued shall be taken into account in evaluating conditions that existed at the balance sheet date, for example, . . . in determining whether an exploratory well or exploratory-type stratigraphic test well has found proved reserves . . .

For example, assume that costs of $248,000 are accumulated on an exploratory well on which drilling is completed prior to December 31, 2000, the balance sheet date. However, on that date the results of the well are uncertain. On February 10, 2001 (before the financial reports are issued for the year ended December 31, 2000), the well is deemed not to have found proved reserves. Under these facts, even though the outcome is uncertain on December 31, 2000, the costs of $248,000 accumulated on December 31, 2000, should be charged to expense in 2000 for the period in which they are incurred.

A slightly different situation occurs when an exploratory well whose drilling was in progress at the year-end is found to be a dry hole prior to the date the financial statements are issued. In this event, a question arises as to not only the proper treatment of the costs incurred during the period ending on the balance sheet date but also the treatment of any costs incurred after that date. FASB's Interpretation No. 36 (see Oi5.130 in Appendix 3) requires that the costs incurred after the balance sheet date must be charged to expense in the period following the balance sheet date, while costs accumulated through the balance sheet date must be charged to expense in the period ending with the balance sheet date. Equipment salvage proceeds should be considered.

For example, suppose that Our Oil Company begins drilling an exploratory well in November 2000. During November and December drilling costs totaling $260,000 are incurred. During January and early

February 2001, additional drilling costs of $108,000 are incurred. The well is determined on February 13, 2001, to be dry. Financial statements for 2000 are issued on March 10, 2001. Under the requirements of FASB Interpretation No. 36, the $260,000 of costs incurred and accumulated through December 31, 2000, less expected related salvage proceeds, will be charged to expense in 2000, and the costs of $108,000 incurred in January and February, net of related salvage proceeds, are charged to expense in 2001.

DEFERRAL OF COSTS OF AN EXPLORATORY WELL WHOSE OUTCOME IS NOT IMMEDIATELY ASCERTAINED

Oi5.122 provides guidance on whether to expense or defer exploratory well costs when the well's success is not determinable at the time drilling has been completed:

> Occasionally, however, an exploratory well may be determined to have found oil and gas reserves, but classification of those reserves as proved cannot be made when drilling is completed. In those cases, one or the other of the following subparagraphs shall apply depending on whether the well is drilled in an area requiring a major capital expenditure, such as a trunk pipeline, before production from that well could begin:
>
> a. Exploratory wells that find oil and gas reserves in an area requiring a major capital expenditure, such as a trunk pipeline, before production could begin. On completion of drilling, an exploratory well may be determined to have found oil and gas reserves, but classification of those reserves as proved depends on whether a major capital expenditure can be justified which, in turn, depends on whether additional exploratory wells find a sufficient quantity of additional reserves. The situation arises principally with exploratory wells drilled in a remote area for which production would require constructing a trunk pipeline. In that case, the cost of drilling the exploratory well shall continue to be carried as an asset pending determination of whether proved reserves have been found only as long as both of the following conditions are met:
>
>   1. The well has found a sufficient quantity of reserves to justify its completion as a producing well if the required capital expenditure is made.

2. Drilling of the additional exploratory wells is under way or firmly planned for the near future.

Thus, if drilling in the area is not under way or firmly planned, or if the well has not found a commercially producible quantity of reserves, the exploratory well shall be assumed to be impaired, and its costs shall be charged to expense.

b. All other exploratory wells that find oil and gas reserves. In the absence of a determination as to whether the reserves that have been found can be classified as proved, the costs of drilling such an exploratory well shall not be carried as an asset for more than one year following completion of drilling. If, after that year has passed, a determination that proved reserves have been found cannot be made, the well shall be assumed to be impaired, and its costs shall be charged to expense.

Oi5.125 provides similar guidance for stratigraphic test wells:

Exploratory-type stratigraphic test wells are normally drilled on unproved offshore properties. Frequently, on completion of drilling, such a well may be determined to have found oil and gas reserves, but classification of those reserves as proved depends on whether a major capital expenditure, such as a production platform, can be justified which, in turn, depends on whether additional exploratory-type stratigraphic test wells find a sufficient quantity of additional reserves. In that case, the cost of drilling the exploratory-type stratigraphic test well shall continue to be carried as an asset pending determination of whether proved reserves exist only as long as both of the following conditions are met:

a. The well has found a quantity of reserves that would justify its completion for production had it not been simply a stratigraphic test well.
b. Drilling of the additional exploratory-type stratigraphic test wells is under way or firmly planned for the near future. Thus, if associated stratigraphic test drilling is not under way or firmly planned, or if the well has not found a commercially producible quantity of reserves, the exploratory-type stratigraphic test well shall be assumed to be impaired, and its cost shall be charged to expense.

Notice that the above quotations from Oi5.122 and Oi5.125 actually cover two types of situations. Oi5.122(a) and Oi5.125 address accounting for wells finding reserves, but classification of the reserves as proved depends on the success of additional well(s) being drilled or firmly planned. Oi5.122(a) applies to regular exploratory wells from which production of oil and gas is expected if reserves are found, while Oi5.125 applies to stratigraphic wells from which it is not feasible to secure production even if reserves are found. Oi5.122(b) covers all other situations in which the outcome of the well is inconclusive.

Two examples can be used to demonstrate the situation in which reserves are found but additional capital outlays are necessary before production can begin. Frequently, an exploratory well will discover natural gas reserves in an area where no pipeline is available. However, in order to justify building a pipeline, additional reserves will be necessary. Existence of these reserves can be determined only by the drilling of additional wells. In order to determine whether the costs of the discovery wells shall be deferred, the first test to be made is whether the well has found enough reserves to justify its completion if the necessary pipeline were in fact available. If the answer to this question is no, the accumulated costs will be expensed. On the other hand, if the answer is yes, the costs may be initially deferred. However, the second test must then be applied. Is the additional drilling either in progress or planned for the near future? If the drilling is, in fact, in progress or if there are concrete plans for near-term drilling, the costs may appropriately be further deferred. Otherwise, the costs must be charged to expense.

A second illustration of this concept is commonly found in offshore activities. A stratigraphic test well may be drilled to search for minerals. If oil or gas is found, it cannot be produced from the well, but its discovery will lead to the drilling of additional stratigraphic-type test wells, construction of a permanent platform, or drilling of wells to produce the minerals. Again the two tests must be applied: (1) Were enough reserves found to justify completion had it not been simply a stratigraphic-test well, and (2) Is drilling of the additional wells under way or planned for the near future?

Obviously, in the two situations described above, there is no great problem if the additional drilling is under way. However, interpretation of the phrase *firmly planned for the near future* is a subjective matter. What is meant by *firmly planned* and by *near future?* Clearly, *firmly planned* suggests that concrete action has been taken by responsible management to plan the necessary activities, including the appropriation of funds, development of a definite timetable of action, and communication of the plan to those in the company responsible for carrying out the plan. The term *near future* would appropriately be interpreted in light of all circumstances, including the *firmness* of plans, the availability of equipment and personnel, legal obligations and restrictions, and other factors.

Oi5.122(b) provides for a one-year limit on deferring the costs of an exploratory well when classification of associated reserves as proved or unproved is not dependent on additional capital outlays. If reserve classification is still uncertain after one year, the well shall be assumed to be impaired, and its costs charged to expense. This provision certainly does not suggest that costs of exploratory wells should be automatically deferred for one year. The deferral is proper only when reserve classification is uncertain. Costs of the well should be charged to expense when there is evidence that proved reserves were not found.

Paragraph 199 of FAS 19 clarifies that the intent of the FASB was to "prohibit the indefinite deferral of the costs of exploratory wells merely on the hope that the selling prices of oil and gas will increase or on the possibility that unplanned exploratory drilling activity in the indefinite future might find additional quantities of reserves."

FULL COST ACCOUNTING FOR EXPLORATORY WELL COSTS

Under full cost, all costs of exploratory wells, whether successful or dry, are capitalized. The Work in Progress account is used to accumulate costs of wells being drilled in the same way as for successful efforts companies. All accumulated costs may be closed into the wells and related facilities accounts at the end of each period, or they may be left in Work in Progress until the outcome of the well is known.

The Work in Progress account may be included in the amortization calculation, or it may be omitted from the calculation. In any event, as soon as the outcome of the well is known, its costs must be included in the amortization computation.

SUCCESSFUL EFFORTS ACCOUNTING FOR DEVELOPMENT WELL COSTS

For companies using the successful efforts method of accounting, all development costs are to be capitalized [Oi5.103(b)]. Development costs are defined in Oi5.112:

> Development costs are incurred to obtain access to proved reserves and to provide facilities (refer to paragraph .117) for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:
>
> a. Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
> b. Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
> c. Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.
> d. Provide improved recovery systems.

Reg. S-X Rule 4-10(a)(16) provides a similar definition of development costs.

Obviously, if the costs of exploratory dry holes and stratigraphic test wells that do not find proved reserves are to be expensed while all costs of development dry holes and all costs of development-type stratigraphic test wells that are not completed as producers are to be capitalized, the distinction between development wells (including development-type stratigraphic test wells) and exploratory wells (including exploratory-type stratigraphic test wells) becomes very important. Reg. S-X Rule 4-10 provides guidance in making this distinction by defining the terms *exploratory well*, *development well*, and *stratigraphic test well*:

> **Exploratory well.** A well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive or oil or gas in another reservoir, or to extend a known reservoir. Generally, an exploratory well is any well that is not a development well, a service well, or a stratigraphic test well as those items are defined below [This sentence is similar to the Oi5.402 definition of exploratory well].

Development well. A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive [identical to the Oi5.401 definition].

Stratigraphic test well. A drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intention of being completed for hydrocarbon production. This classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as (i) *exploratory-type*, if not drilled in a proved area, or (ii) *development-type*, if drilled in a proved area [quite similar to the Oi5.408 definition].

The definitions severely limit the types of wells to be considered development wells. For example, wells drilled to define the perimeters of a reservoir are exploratory wells, *not* development wells. A well drilled to a formation (horizon) in which no proved reserves have been found is classified as an exploratory well even if production has been secured from another horizon on the lease. Only if the well is drilled *within* the proved area and to the depth of a stratigraphic horizon known to be productive is it classified as a development well; thus, *outpost* wells or *step-out* wells are exploratory wells. There should be very few development dry holes; those that do occur are likely to result from faulting of the strata or from mechanical problems while drilling.

Assume that the well is drilled within the confines of a proved area with the intent to extract minerals from a currently producing formation. Costs were $6,000 for casing and $96,000 for drilling. The costs are charged to Work in Progress as they are incurred:

241	Work in Progress—Intangible Costs	96,000	
243	Work in Progress—Tangible Costs	6,000	
	301 Vouchers Payable		102,000

To record cost incurred for drilling and casing the DiTirro #3 well.

Before the well reached the stage of completion, a structure was encountered that made it impossible to continue drilling. The well was abandoned, and none of the casing was salvaged. The abandonment would be recorded as follows:

231	Intangible Costs of Wells and Development	96,000	
233	Tangible Costs of Wells and Development	6,000	
	241 Work in Progress—Intangible Costs		96,000
	243 Work in Progress—Tangible Costs		6,000

To record abandonment of the DiTirro #3 development well and transfer of costs to Proved Property Well and Development Costs.

The same entry would be made if production had been obtained from the development well.

The seemingly inconsistent treatment between costs of unsuccessful exploratory wells and costs of unsuccessful development wells is supported by FAS 19 (Paragraphs 204 through 207) on the grounds that once proved reserves have been found, development costs result in the creation of a producing system of wells and related facilities much like the production system of a manufacturing company. Paragraphs 204 and 205 of FAS 19 state:

> After discovery, all costs incurred to build that producing system, including the costs of drilling unsuccessful development wells and development-type stratigraphic test wells, are capitalized as part of the cost of that system. . . . There is an important difference between exploratory dry holes and development dry holes. The purpose of an exploratory well is to search for oil and gas. The existence of future benefits is not known until the well is drilled. Future benefits depend on whether reserves are found. A development well, on the other hand, is drilled as part of the effort to build a system of wells and related equipment and facilities. Its purpose is to extract previously discovered oil and gas reserves.

Refer back to Figure 8-12 for an illustration of distinguishing development wells from exploratory wells.

FULL COST ACCOUNTING FOR DEVELOPMENT WELL COSTS

The accounting principles and procedures used for development well costs are the same under full cost as under successful efforts.

SPECIAL PROBLEMS IN ACCOUNTING FOR DRILLING AND DEVELOPMENT

A number of situations frequently occur in drilling and development activities that give rise to more complicated accounting questions. Some of the problems result from the distinction between exploratory wells and development wells. Others arise because of a halt or delay in drilling activities. These situations do not create accounting problems for companies using the full cost method because all drilling and development costs are capitalized under that approach. Although different companies using the successful efforts method follow different procedures in accounting for many of these situations, the authors suggest that those offered below are logical.

DEEPER DRILLING BEYOND PRODUCING HORIZONS

If a well is drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive (a development well) and continues to be drilled deeper into unproven strata, is it a development well or an exploratory well? It seems unreasonable to regard the well as entirely either a development well or an exploratory well. Hence, it is considered reasonable to treat the well (i.e., the single long hole) as two wells for accounting purposes, whereby the cost to drill to the proven horizon is treated as development costs, and the incremental cost to drill deeper exploring for additional reserves is an exploratory cost.

Frequently, in drilling an exploratory well, the operator will discover oil in commercially productive quantities and will complete the well (or plan to complete the well) at that level but will then drill deeper in the same hole to explore another formation found to be noncommercial. The costs of drilling to the producing horizon are capitalized as the costs of a successful exploratory well, but the additional incremental costs of drilling deeper without finding additional proved reserves should be charged to expense as unsuccessful exploratory drilling cost.

Similarly, if the operator enters a producing well and drills deeper to an unproved horizon, the incremental costs should be charged to expense if no production is secured at the greater depth.

PLUG-BACK AND COMPLETION AT SHALLOWER DEPTH

The inverse of the situation described above also might occur. For example, suppose that the operator drilled an exploratory well, with a formation at 9,000 feet as the target. At 6,000 feet, a formation containing hydrocarbons was encountered. Drilling was continued to the 9,000-foot test depth, but no hydrocarbons were found at that level. The operator then plugged back to the 6,000-foot level and completed a producing well from that formation. The incremental costs applicable to the drilling between 6,000 feet and 9,000 feet should be charged to expense as unsuccessful exploratory drilling costs, and the costs of drilling to the producing horizon at 6,000 feet along with the completion costs should be capitalized as costs of wells and related facilities. Some companies also charge to expense a portion of the costs of drilling to the upper producing horizon on the basis that these costs were necessary to drill the lower portion of the well that had been abandoned.

Obviously questions will arise as to how drilling costs should be allocated between the portion of the well abandoned and the portion resulting in production. A mere per-foot allocation probably would not be appropriate. Preferably the incremental costs applicable to the abandoned portion should be the amount expensed. When this is impractical, a per-day apportionment might be satisfactory.

COSTS OF ABANDONED PORTION OF WELL

Sometimes in the drilling of an exploratory well with a specific formation or trap as an objective, difficult drilling conditions may be encountered, making it necessary to abandon the hole already drilled and to start a new well nearby. If the second hole is completed as a producer, the question arises for successful efforts as to whether the costs incurred on the abandoned hole should be charged to expense or should be capitalized as part of the cost of the completed well that found proved reserves.

It appears that the former treatment is preferable and that the costs applicable to the abandoned hole should be charged as an exploratory dry-hole expense because the abandoned hole added nothing to the utility or value of the well actually completed. If the well originally being drilled were classified as a development well under Oi5.401, all costs involved would be capitalized. If in drilling a well difficulties are encountered and it is necessary to abandon the lower portion of the well in order to *plug-back* and *side-track* to reach the same objective through directional drilling, the cost of the abandoned portion should likewise be charged to expense as dry-hole cost.

Some companies do, however, capitalize costs of an abandoned well if the target of the second well (or the sidetracking) is the same as that of the abandoned well. The second well (or *twin well*) and the sidetracking are simply unexpected additional costs, like *fishing* for stuck drill pipe, to get a well drilled to the target.

AFE SYSTEM FOR DRILLING AND DEVELOPMENT

It is necessary for management to exercise close control over expenditures, especially when large amounts are involved, if it is to achieve the goal of maximum profit realization. One tool commonly used for controlling drilling and development costs is the Authorization (or Authority) for Expenditures (AFE) system that has been illustrated in Chapter Six in the discussion of accounting for geological and geophysical exploration.

AFEs are a part of the overall capital budgeting process. An E&P company budgets for capital projects by assessing major capital needs and available financing for the coming year. In general capital projects are ranked as to expected internal rate of return, overall expected profitability, and other factors. Those projects with the highest rankings are financed first, tempered by the need to spread investment to several projects to reduce the risk of no success in the exploratory program. Some discretion is required because expected project profitability can change during the year and unexpected projects can arise that should be funded, such as major well repairs or development of a major new discovery. To finance unexpected capital needs, the E&P company maintains lines of credit and borrows funds when prudent to do so.

The AFE system uses an AFE form (Figure 9-1) to document (1) the expected costs of a project for review by management and joint venture partners and (2) their approval to proceed with the project. It is customary and desirable to require an AFE for all major projects in drilling and equipping oil and gas properties, purchasing drilling equipment and service units, and constructing field facilities and buildings. It is not practical, however, to obtain specific approval for minor capital items, such as minor equipment replacement or supplies that are bought in routine operations, so standing authorizations for small purchases are generally provided. The standing authorization simply gives the responsible department head authority to purchase specified items within limits of the budget for certain items without individual approval from higher management.

In most companies AFEs are not required for operating expenses other than for costs of well workover projects. Even for workover jobs, an AFE is usually unnecessary unless the total estimated cost is greater than some specified amount, for example, $20,000.

SUMMARY OF PROCEDURES USED FOR AFES

The following summary outlines AFE system procedures and suggests the nature of forms and records required to implement the system.

1. Asset acquisitions and construction are budgeted, where possible, at least one year in advance.
2. Even if an E&P company only has a small working interest in a well or project, the AFE system tracks and compares budgeted and actual costs for the full *8/8ths* or 100 percent working interest. The full project costs are simply easier for a petroleum engineer to review, compare, and evaluate than the company's net costs. However, the accounting ledgers and subledgers reflect the company's net cost for its share of the working interest.
3. Authority for carrying out a specific project is required by proper operating personnel, usually the district superintendent or division superintendent.
4. Approval is given by appropriate management officials for carrying out each project. The approval is in the form of an AFE (Figure 9-1). Each AFE is assigned a number, and the project it covers is identified by this AFE number. The AFE budgets by project and by subaccount cost category.
5. A project's costs are accumulated in Work in Progress accounts.
6. For each project, actual costs incurred are periodically compared by subaccount to budgeted costs. Differences are assessed and, depending on acceptable limits of cost overruns, a supplemental AFE may be required.

Figure 9-1: Illustrative AFE for Drilling

Authorization for Expenditure
for drilling wells

AFE # 00-017

Well Description:

Operator:	Our Oil Company	Well No. 1		Target Depth	12,000'
State:	Miss.			Target Formation (s)	Smackover
County:	Clark			Well Type	Oil
Prospect/Field	Wildcat				
Well Location	500' FWL & 1250'FNL of Sec. 33-T2N-R17E				

	Budgeted Costs:	Cost to Casing Pt.	Cost to Complete	Total Well Costs
	INTANGIBLE			
001	Footage (or Turnkey) Ft @ $ /ft.			
002	Day Rate: 37 and 12 days @ $5,200/day	$192,400	$62,400	$254,800
003	Site Preparation, roads, pits	89,800	3,500	93,400
004	Bits, Reamers, Tools	42,000	2,500	44,500
005	Labor – Company			
006	Labor – Other	1,500	1,500	3,000
007	Fuel, Power, Water	17,000	5,500	22,500
008	Drilling Supplies	1,000		1,000
009	Mud and Chemicals	50,000	5,000	55,000
010	Drill Stem Tests			
011	Coring, Analysis	4,000		4,000
012	Electric Surveys, Logs	40,000		40,000
013	Geological and Engineering	2,000	1,000	3,000
014	Cementing : Surface	21,000		21,000
015	Intermediate			
016	Oil String		20,000	20,000
017	Float Equipment, Centralizers, Etc.	4,000	2,500	6,500
018	Completion, Frac., Acidizing, Perforating		13,500	13,500
019	Rig Transportation, Erection, Removal, Other Transp.	54,500	10,000	64,500
020	Other Services	70,000	15,000	85,000
021	Overhead	2,000	700	2,700
022	Miscellaneous	25,000		25,000
	TOTAL INTANGIBLE COSTS	616,200	143,200	759,400
	TANGIBLE			
030	Casing			
031	Surface Ft 16" OD@ $/Ft	3,500		3,500
032	Intermed. 3,000 Ft 9 5/8" OD@ 16.00 $/Ft	48,000		48,000
033	Production 12,550 Ft 5 ½" OD@ 10.75$/ft		135,000	135,000
034	Liner Ft OD@ 10.75 $/Ft			
035	Tubing 12,300 Ft 2 3/8" OD@ 2.75 $/Ft		33,800	33,800
036	Rods Ft OD@ $/Ft			
037	Well Head and Subsurface	3,000	17,000	22,000
038	Pumping Units			
039	Tanks		5,300	5,300
040	Separators		20,000	20,000
041	Heaters – Treaters		3,000	3,000
042	Engines and Motive Power			
043	Flow Lines			
044	Miscellaneous Equipment		2,300	2,300
045	Installation Costs of Surface Equipment			
	TOTAL TANGIBLE COSTS	54,500	216,400	270,900
	TOTAL WELL COSTS	$670,700	$359,600	$1,030,300

Approvals

		Name	Date
	Prepared by	E.N. Gineer	4/10/00
Operator's internal approvals:	Division	T. Boss	4/10/00
	Corporate	T. Rex	4/12/00

Approvals of Working Internet Owners:

Owner	WI%	Costs to Casing Pt.	Costs to Complete	Approved By	Date
Operator	60%	$402.420	$215.760	See above	See above
ABC Oil Co.	40%	268.280	143.840	A.B. Cloud	4/16/00
Total	100%	$670.700	$359.600		

AFE EXAMPLE

Our Oil Company budgets drilling operations, insofar as possible, one year in advance. The company has made plans to drill an exploratory well during the current year on a 200-acre lease obtained from R. L. Jones in Clarke County, Mississippi. The budget calls for drilling one well to 12,000 feet on the property and, if the well is productive, installing necessary well and lease equipment. Estimated total cost of drilling the well is $616,200 for intangibles and $54,500 for well equipment associated with drilling. Estimated costs to complete and equip the well if it is successful are $359,600 (Figure 9-1).

The AFE form used for drilling activities is designed so that it can also be used for completion of wells, installation of production equipment, installation of lease equipment, and well workover jobs.

Companies typically prepare exploratory well AFEs showing estimated costs to both drill and complete the well. If the exploratory well finds reserves and is to be completed, a copy of the original drilling AFE is used as the form for the completion and equipping AFE. If the well is completed as a producer, the AFE form will have two numbers assigned to it, the first number being the drilling AFE covering amounts in the drilling cost money column (*costs to casing point*) and the second number being the completion AFE covering the amounts in the completion cost column. Total drilling and equipping costs can then be entered in a third column for completed well costs (see Figure 9-1).

The AFE numbering system used in Our Oil Company is a five-digit-number, the first two being the last two digits of the year and the last three numbers being the sequential numbers of the AFE for the year. The AFE in Figure 9-1 contains approval to drill an exploratory well. The AFE shows a detailed breakdown of the total expected drilling costs of $616,200 for intangibles and $54,500 for casing and other subsurface equipment. Authorization is complete when proper signatures have been affixed to the request. A time limit should be set for beginning the project, after which a new appropriation will have to be made for the project to start. This time limit helps the financial requirements to be better estimated and controlled.

The request for approval of expenditures is usually accompanied by statements showing in detail how the estimated costs were determined. In many companies, the supporting analysis indicates costs that will require cash outlays and those that will use items already on hand so that cash requirements may be readily ascertained.

SUPPLEMENTAL AFE

Periodically as the project progresses, expenditures actually incurred to date are compared with estimated costs. It may become evident as the work progresses that the amounts authorized for certain elements of cost will be insufficient. Company policy, the initial AFE, or occasionally the joint venture operating agreement may require a supplemental AFE for actual costs exceeding ten percent (or other stated percentage) of the original budgeted and authorized total project costs. The operating agreement does not normally require the joint venture operator to issue a supplemental AFE to the joint venture nonoperators. So the AFE may reflect the operator's preference that no supplemental AFE is required for budget overruns, or the AFE may contain language beneficial to nonoperators that the operator must issue a supplemental AFE for nonoperator approval for expenditures exceeding ten percent (some say 15 percent) of the initial AFE's approved budget.

Consideration should also be given to detailed analysis of over-expenditures by category of costs as opposed to only total AFE over-expenditures. Comparisons of authorized costs and actual costs help identify errors in accounting, vendor billing, and AFE budgeting.

INTEREST CAPITALIZATION

FAS 34 requires that a portion of interest costs incurred during the *construction period* of assets should be capitalized:

> .06 The historical cost of acquiring an asset includes the costs necessarily incurred to bring it to the condition and location necessary for its intended use. If an asset requires a period of time in which to carry out the activities necessary to bring it to that condition and location, the interest cost incurred during that period as a result of expenditures for the asset is a part of the historical cost of acquiring the asset. The term *intended use* embraces both readiness for use and readiness for sale depending on the purpose of acquisition.

Qualifying assets include assets that are produced for a company's own use, including oil and gas properties and facilities. The interest to be capitalized is conceptually the amount of interest cost that would not have been incurred if the project had not been undertaken. The appropriate interest rate (detailed in FAS 34) is applied to the average amount of capitalized cost of the project during the year. The total interest cost capitalized in an accounting period shall not exceed the total interest cost incurred by the enterprise in that period.

Interest costs are capitalized only during the period that three conditions are met:

1. Capital expenditures have been made.
2. Activities necessary to ready the asset for its intended use are in progress.
3. Interest costs are being incurred.

For oil and gas companies using the successful efforts method, the major questions relating to interest capitalization have centered around the time at which interest capitalization may begin and the time it must end. For example, assume the following activities were undertaken and carried out on the dates indicated.

January 2, 2000	Leases acquired on a prospect.
July 1-August 31, 2000	Seismic and other exploration work carried out on leases.
June 1, 2001	Exploratory drilling begun.
August 15, 2001	Exploratory well completed as a producer.

One might argue that FAS 34 permits capitalization of interest on the project only during the period, July 1, 2000, through August 31, 2000, and the period June 1, 2001, through August 15, 2001, because it was only during these periods that physical activities are being carried out. However, Paragraph 17 of FAS 34 provides:

> . . . The term *activities* is to be construed broadly. It encompasses more than physical construction; it includes all the steps required to prepare the asset for its intended use. For example, it includes administrative and technical activities during the preconstruction stage, such as the development of plans for the process of obtaining permits from governmental authorities; it includes activities undertaken after construction has begun in order to overcome unforeseen obstacles, such as technical problems, labor disputes, or litigation. If the enterprise suspends substantially all activities related to acquisition of the asset, interest capitalization shall cease until activities are resumed. However, brief interruptions in activities, interruptions that are externally imposed, and delays that are inherent in the asset acquisition process shall not require cessation of interest capitalization.

Because of this broad interpretation of *activities*, there is a wide variety of practices for choosing the starting date and ending date for interest capitalization by successful efforts companies. For that reason, there is a wide divergence in interest capitalization practices. For example, analyzing seismic charts, arranging financing, arranging for drilling rigs, and various other nonphysical activities have been deemed by some companies to be qualifying activities. Thus, some companies follow the practice of capitalizing interest on the average balance of unproved properties as well as on costs applicable to drilling and development in progress. The *1999 PricewaterhouseCoopers Survey of U.S. Petroleum Accounting Practices* found that nine of 31 respondents using successful efforts capitalized interest on unproved leasehold costs during ongoing activities.

In the authors' opinions, the following assets qualify for interest capitalization under FAS No. 34:

1. **Undeveloped leases.** Undeveloped leases qualify for interest capitalization as long as exploration activities necessary to get the lease ready for its intended use are in progress. Interest capitalization should begin with the first expenditure to explore the lease and should continue, assuming exploration activities are continuous, until the property is ultimately written off or until it is capable of producing and delivering oil or gas. Qualifying activities could include pre-field administrative and technical work, such as:

   - Work performed by internal or external geologists and engineers to identify areas that may warrant further examination and to examine specific areas that are believed to contain oil and gas,
   - Title opinion curative work, and
   - Obtaining work permits from regulatory agencies.

   The payment of delay rentals in itself seems inadequate evidence that exploration activities are being performed. In the case of an undeveloped lease that covers a large number of acres, the circumstances and activity must be carefully reviewed to determine whether the work being done on a portion of the acreage allows interest capitalization on the entire block of acreage.

2. **Shut-in properties.** As suggested by Oi5.122 and Oi5.125, occasionally an exploratory well may be determined to have found oil and gas reserves, but classification of those reserves as proved cannot be made until additional testing and evaluation can be done. Oi5.122(b) allows the well's capitalized costs to be carried as an asset for up to one year. In these circumstances, interest capitalization can continue up to the one-year limitation, assuming that exploration activities are continuous.

   Wells that are capable of production but are awaiting the construction of additional facilities (e.g., gas wells awaiting construction of a pipeline) are qualifying assets for which interest capitalization can continue as long as development activities on the pipeline remain continuous. However, wells that are shut in because of lack of a market or because of depressed gas prices do not qualify for interest capitalization.

3. **Drilling and development costs.** Costs of drilling and developing proved properties, including costs of unsuccessful development wells, should be capitalized as part of the cost of oil and gas properties. Assuming that development activities are continuous, development costs qualify for interest capitalization until the related property is capable of producing and delivering oil or gas.

   Significant development costs (e.g., an offshore production platform) are often incurred in connection with a planned group of development wells before all the planned wells have been drilled. Oi5.126 allows exclusion of a portion of those development costs in determining the unit-of-production amortization rate until additional development wells are drilled. In these circumstances, interest capitalization could continue on the portion of development costs deferred as long as development activities are continuous.

4. **Oil and gas leases held for resale or contribution to a partnership.** In many cases, leases held for resale or contribution to a partnership do not qualify for interest capitalization because qualifying activities are not being performed on the property. However, if the company is performing activities (e.g., geological and geophysical work) to prepare the lease for resale or

contribution, the property should qualify for interest capitalization as long as the activities are continuous.

FAS 34 does not require specific identification of interest expense with an expenditure for an asset. However, FAS 34's Paragraph 16, does specify that interest capitalization may be applied only to "capitalized expenditures (net of progress payment collections) for the qualifying asset that have required the payment of cash, the transfer of other assets, or the incurring of a liability on which interest is recognized (in contrast to liabilities such as trade payables . . .)."

For example, assume that Company A normally paid its vendors on 90-day terms and the vendors did not charge interest on the outstanding balance. Also, assume that Company A drilled, tested, and completed a well in 60 days. In this example, Company A would not be able to capitalize any interest as part of the acquisition cost of the well, because the well was completed and ready for its intended use before any net capitalized expenditures were made.

FAS 34 also indicates that reasonable approximations of net capitalized expenditures may be used. Therefore, it is not necessary to prepare detailed analyses of payment dates to determine the point in time that capitalized costs become capitalized expenditures.

The Capitalization Period

To qualify for interest capitalization, activity does not have to be performed on each asset every day. Brief interruptions in activities, interruptions that are externally imposed, and delays that are inherent in the asset acquisition process do not require cessation of interest capitalization. However, if substantially all activities related to acquisition of an asset are suspended, interest capitalization should cease until activities are resumed. For example, if a company determines that an exploration project is too expensive or risky to pursue without joint venture partners and basically suspends all activities on the project until joint venture partners are located, interest capitalization should cease. When activities resume, the project would again qualify for interest capitalization.

FAS 34 provides that interest capitalization is to end when the asset is substantially complete and ready for its intended use. Generally, this would be when proved reserves have been discovered through drilling of a successful exploratory well because it is at this time that the lease becomes part of the producing asset system under the successful efforts accounting rules. However, Paragraph 18 of FAS 34 refers specifically to an exception to this rule for companies using successful efforts accounting:

> . . . Some assets cannot be used effectively until a separate facility has been completed. Examples are the oil wells drilled in Alaska before completion of the pipeline. For such assets, interest capitalization shall continue until the separate facility is substantially complete and ready for use.

Similarly, interest may be capitalized for a well until the well is completed, since the well cannot be used effectively until its completion.

Immaterial Activity

FAS 34's Paragraph 8 provides that interest capitalization is not required in circumstances in which the capitalization effect is immaterial. For example, most larger companies (and some smaller ones) establish a policy that interest is not to be capitalized unless the individual project or program has a total cost expected to exceed a specified threshold. The *1999 PricewaterhouseCoopers Survey of U.S. Petroleum Accounting Practices* found that five of the six major companies responding to the survey had such policies. Three of these companies had established thresholds of at least $100 million. Approximately 30 percent of the responding independent companies had established capitalization thresholds. All but one used thresholds of at least $1 million.

Another convention is the establishment of a minimum required length of the project or program before interest on the expenditures is capitalized. Frequently, the minimum time period required for capitalization is six months to one year. These conventions eliminate the administrative costs of capitalizing insignificant interest costs associated with numerous small capital construction projects and short construction periods.

Interest Capitalization Under Full Cost Accounting

FAS Interpretation No. 33 clarified the interest capitalization rules for oil and gas producers using the full cost method. That interpretation said that full cost companies should capitalize interest only on assets that have been excluded from the full cost pool amortization. Assets being amortized are deemed to relate to reserves being produced and thus to constitute assets being used in the earning process; hence, interest related to those assets cannot be capitalized. Capitalized interest becomes a part of the cost of the related properties or projects and will be subject to amortization when the costs of the assets are transferred to the amortization pool.

Chapter Ten

ACCOUNTING FOR JOINT OPERATIONS

Previous chapters have emphasized that oil and gas exploration and development activities are extremely high-risk ventures, with two-thirds of U.S. exploratory wells in 1998 being abandoned as dry holes. Not only are these activities inherently risky, but they frequently require enormous investments up front. For example, an offshore block may cost the lessee $25 million, while exploration, drilling, and development of the property may cost hundreds of millions of dollars. Most of these costs may be incurred prior to the time that it is known whether reserves exist or before the quantity of reserves is ascertained. Thus, it is not surprising that otherwise fiercely competitive companies routinely combine their capital and knowledge in *joint operations* to acquire, explore for, develop, and produce oil and gas under extremely costly and hazardous conditions, such as those in offshore areas, because they need to share the risk and high costs involved.

Even in areas that are not especially hazardous and where costs are not enormous, cooperation makes good economic sense or may be dictated by social concerns. For example, if several operators own working interests in small leases in an area of interest, it would be wasteful for every operator to drill wells on every property. Not only would a large number of wells not be necessary to produce the oil or gas in the reservoir, but state spacing laws might actually prohibit drilling on each property. In addition to the waste in drilling and equipment costs, the administrative and supervisory efforts required by each operator in carrying out a drilling project involving only one or two wells and then producing the reserves from those wells may be greater than the potential benefits from the wells.

In some instances development and production activities may be almost impossible unless the mineral owners are willing to join together. For example, secondary or tertiary recovery techniques cannot generally be employed economically on only that part of a reservoir underlying a single lease but must be applied to the reservoir as a whole. Only if all owners participate in the project is it practical. Finally, good conservation practices dictate that production of the reservoir must be carefully planned and controlled, which requires cooperation between mineral owners in the reservoir. Thus, jointly conducted operations are routine throughout the petroleum industry.

LEGAL FORMS OF JOINT ACTIVITIES

There are three different legal forms generally used for joint operations.

1. **Joint ventures of undivided interests.** By far the most important and most common form of joint venture in the oil and gas industry is the joint venture of undivided interests or unitized interests in which working interest owners join together for the drilling, development, and operation of a jointly owned or unitized property or properties in accordance with a written agreement entered into by and between them. The term *joint venture* usually refers to ventures in which the parties own undivided interests (including divided interests that through unitization effectively become undivided interests) referred to as joint interests.[19]
2. **Legal partnerships.** Oil and gas entities may join together in carrying out an exploration and development project by forming a partnership under state law. The partnership will itself be a legal entity and will hold title to assets, incur debts in its own name, and otherwise carry on the activities of an entity. Limited partnerships managed by an E&P company as general partner and substantially funded by individual investors as limited partners were popular in the 1970s and early 1980s. Those limited partnerships investing in exploration and development were called *drilling funds*. Those formed to acquire proved producing oil and gas properties were called *income funds*. E&P company joint ventures are not generally structured as legal partnerships for carrying on exploration, development, and production operations. Accounting for partnership interests is discussed in Chapter Twenty-Four.
3. **Jointly owned corporations.** It may be desirable for various legal, political, or economic reasons for oil and gas companies to undertake cooperative ventures through the formation of a separate corporation. For example, three domestic oil companies may wish to undertake exploration and production activities in a foreign country. A new corporation may be formed in the foreign country

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[19] An undivided interest owner has a share in the entire lease or property. For example, the joint owner might own a 50 percent interest in a tract of 640 acres. On the other hand, an owner might own a *divided* interest of 100 percent of the interest in 320 acres included in a 640 lease.

with each of the domestic enterprises owning one-third of the stock in the new company. More commonly, the three enterprises may each own stock in the foreign corporation with either the government of the foreign country or a native corporation in that country also owning stock in the new venture. Similarly, corporations may join together to form a new corporation to build a pipeline, to explore a new area, or to construct secondary recovery facilities.

JOINT VENTURES

This chapter focuses on how a joint interest owner accounts for joint venture activities, particularly the sharing and recording of joint venture costs.

The creation or formation of a joint venture reflects either a pooling of capital or an exchange of like-kind assets. In either event no gain or loss is generally recognized by the parties at the time of the formation, as further addressed in Chapters Twenty-One and Twenty-Three.

The joint venture has a purpose that can involve one or more of the acts of acquiring leases, exploration, development, or production. In order to carry out this purpose, definitions and guidelines must be established under which all parties in the joint venture must operate. Fortunately, the U.S. oil and gas industry has a long history of cooperative ventures from which to draw, and therefore, various model forms for agreements and joint operating agreements have evolved.

PROPERTIES INCLUDED IN JOINT OPERATIONS

In order to conduct joint operations, one or more mineral interests must be delineated as the subject of the venture. The joint venture may cover a single well or project or a single lease but normally covers a group of jointly owned leases of mineral interests. The grouping is typically one of three forms:

1. *Jointly owned leases within an area of mutual interest specified in a joint venture agreement* whereby working interests in oil, gas, or other mineral leases are acquired and held as undivided ownership interests by two or more E&P companies.
2. *A pooled drilling and production unit* in which relatively small leases (or portions of leases) that were separately owned by E&P companies (but not necessarily all the leases in a field) are pooled or combined into a single drilling and production unit. Pooling may result from the designation and creation of the unit by the working interest owners (under the express pooling provisions contained in their separate oil and gas leases granting them the right to so pool the working and royalty interests). The pool or unit may also be created by a separate voluntary pooling agreement joined into by the working interest owners and royalty interests under the separate tracts. In other cases, the royalty owners may not be involved in the pooling arrangement. Drilling and production units frequently do not involve all owners in a field and may be either purely voluntary or forced by government controls. For example, state spacing requirements may decree that a minimum of 40 acres is required for an oil well or a minimum of 640 acres is required for a gas well. Obviously, the owner of a 20-acre lease would have to join with other owners to pool their leases in order to establish a drilling block.
3. *Field-wide unitization* in which all separately owned tracts in a field are unitized into a single unit or property. As discussed in Chapter Twenty-Two, all working interest owners and all royalty owners in the field contribute their separate properties to the unit; in return, they receive smaller fractional interests in the combined properties (and sometimes paying or receiving money under *equalization* settlements). Field-wide or reservoir-wide unitization is especially common when secondary or tertiary recovery, pressure maintenance, or gas cycling operations are to be initiated. Field-wide unitization agreements are more elaborate and complex than those found in simple drilling and production unit pooling operations.

In any of these cases, there are two basic agreements, a *Joint Venture Agreement* that establishes the joint venture and a *Joint Operating Agreement* that governs how the joint venture is to be operated.

JOINT VENTURE AGREEMENTS

Joint venture agreements are often expressed in more specific terms, such as an *exploration agreement*, *pooling agreement*, or *unitization agreement.* The term *joint venture agreement* generally refers to a joint venture agreement that is not a unitization or pooling agreement but an agreement of E&P companies to own undivided interests in specific leases or any leases within a specified large area of land, such as a large portion of a county.

The joint venture agreement states what E&P companies and what leases are in the joint venture, and the companies' respective working interests in the leases. Normally the leases are for adjoining acreage or acreage within a small area.

The agreement typically designates an area surrounding the leases as an a*rea of mutual interest* (AMI) whereby any joint venture owner acquiring leases in the AMI must acquire such leases on behalf of the joint venture. The AMI provision is intended to preclude an owner from unfairly profiting from joint venture information, such as a new discovery on venture leases.

The formation of a joint interest operation, whether it involves a single tract of land, a block of leases jointly owned, or a field-wide unitization, is a matter of negotiation by management representatives advised by their own company's specialists in the geology, land, engineering, legal, tax, and accounting departments and perhaps some outside assistance, if needed, depending on the size of the company, their available resources, and the project scope and size. When executed, the formal written joint venture agreement becomes effective on the date specified therein. It is therefore essential that it be carefully and expertly reviewed by qualified representatives of the respective parties and its form and terms approved prior to execution.

Under all these circumstances one of the working interest owners must be designated as the *operator* to manage the development and operation of the joint venture's properties in an efficient manner. Joint operation of a single property or block of properties is carried out under a joint operating agreement (JOA). The JOA is in addition to the joint venture agreement. The JOA sets out the duties, obligations, rights, and responsibilities of the working interest owners to the joint venture operations and specifies how the costs and benefits are to be shared. Because the JOA is crucial to accounting procedures and principles for joint operations, it is examined in some detail in the following pages.

THE JOINT OPERATING AGREEMENT (JOA)

The operating agreement in the case of a smaller pooled drilling and production unit or a single tract of land generally is not as elaborate or complex as an operating agreement on a field-wide unitization. However, the general principles, purposes, and some provisions of operating agreements in all such situations are essentially the same. The operating agreement form may provide for all or some of the following, depending on the circumstances or size of the operation.

1. **Definitions.** Defines terms such as operator and nonoperator, which are used in the agreement. Also, in the case of a pooled unit or field-wide unit, defines unitized substances, unitized formation, working interest owner, royalty interest owner, and other terms.
2. **Creation and effect of joint operation or unit.** In the case of a single tract of land, describes the oil and gas leases and property involved. In the case of a pooled unit or a field-wide unit, describes the mineral leases, interests, and separate properties, as well as the mineral or minerals unitized, and possibly the producing zones involved, that make up the unitized area.
3. **Interests of parties.** Sets out the participating interest of each working interest owner in the costs and the production of the unit. In field-wide units, may set out participation factors by individual tracts.
4. **Plan of operations.** Provides for a drilling or development program, workover operations, abandonment, and similar activities (and may be separated into several articles). In the case of a single tract or drilling unit, the drilling of the first well is usually expressly agreed upon, and customarily the mechanics of obtaining an agreement for the drilling of any additional well is provided for in this section. Also, if not all working interest owners agree to participate in drilling any subsequent well or wells (referred to as *nonconsent* or *going nonconsent*), provisions are included to permit independent operations, in which the party desiring to drill, complete, rework, recomplete, etc., can do so without consent of the other parties with the consenting parties

absorbing all the costs of a dry hole or the particular operation. In the case of a producing well, the driller will be permitted to recoup a percentage of the drilling and equipping costs out of production attributable to the nonconsenting parties' interests. This percentage is specified in the JOA and might range from 100 percent to 800 percent. However, it generally ranges from 300 percent to 500 percent.

5. **Operator.** Designates the party who is to have control and supervision of the joint operation.
6. **Duties and obligations of operator.** Sets out the powers and duties of the operator to develop and to operate the joint operation area in an efficient manner; requires that lands and leases in the area covered be kept free from third-party statutory liens; describes records and reports to be provided to nonoperators and governmental authorities; explains the procedure for resignation or removal of the operator; and sets out other similar requirements.
7. **Relationship of parties.** Provides that the duties, obligations, and liabilities of the parties are intended to be several and *not* joint or collective. Also provides that nothing contained therein shall ever be construed to create an association or trust or to impose a partnership duty, obligation, or liability with regard to any one or more of the parties. Each party shall be individually responsible for that party's obligations as therein provided. Related to this provision is an agreement that the parties do not intend to operate and be taxed under federal income tax laws as a partnership. The operator agrees to file appropriate forms with the IRS to *elect out of Subchapter K*, i.e., of partnership treatment.
8. **Effective date and term.** Provides when the agreement is to become effective. In field-wide units, requires that a specified percentage of all working interest ownerships and a specified percentage of royalty interest owners must execute the agreement before it becomes effective. Provides the term or period of time the agreement remains in effect after its effective date (e.g., so long as the leases continue in effect, operations are conducted, or production continues).
9. **Allocation of production.** Provides that each party has the right to take in kind or separately dispose of its proportionate share of the oil or gas produced from the joint operation area. Provides that each party shall be responsible for all royalties on its share of the

production and hold other parties free from liability. Sometimes delegates to the operator the duty to keep the records and handle the payment of royalties. The right to take oil and gas in kind is a defense against IRS assertion that the joint venture is really a taxable corporation.

10. **Taxes.** May provide that the operator shall render for *ad valorem* tax purposes all jointly owned property and pay these taxes for the benefit of the parties in accordance with the applicable provisions of the Accounting Procedure (discussed in the next section). May provide that each party renders separately and pays its individual account. Also, specifies that each party is responsible for the payment of production, severance, excise, gathering and all other taxes on its proportionate share of the oil and gas produced.
11. **Insurance.** Provides that the operator carry specified types of insurance such as workman's compensation, employer's liability, comprehensive public liability, and comprehensive automobile liability. Sets out the limits of coverage. Provides that if the operator does not comply with the above, the operator shall assume all risks and shall be solely liable. Provides for payment of premiums in accordance with applicable provisions of the Accounting Procedure.
12. **Development and operating costs.** Provides that, with exceptions otherwise specifically provided, the operator shall promptly pay and discharge all costs and expenses incurred in the development and operation of the joint interest area and shall charge all of the parties with their proportionate shares on the basis provided in the Accounting Procedure exhibit attached to the operating agreement. Grants operator the right to demand from time to time and receive from other parties payment in advance of their shares of the estimated costs to be incurred during the next succeeding month (*cash calls*). Requires that the operator shall not undertake any single project reasonably estimated to require an expenditure in excess of a stipulated amount without consent from nonoperators.
13. **Claims and litigation.** Provides that if any party to the agreement is sued on an alleged cause of action arising out of operations in the joint interest area involving titles of any single tract subject to the agreement, that party shall give prompt written notice to the operator and all other parties. Provides also that suits may be settled only with the consent of all parties. Provides that

no charges shall be made for services of staff attorneys of the parties. Provides that outside attorneys shall be employed only with the consent of all parties and that costs so incurred, along with other costs incurred in defense of suits when properly authorized, shall be considered costs of operation and shall be charged to and paid by all parties in proportion to their interests in the joint interest operation.

14. **Force majeure.** Provides that all obligations of each party, except payment of money, shall be suspended while that party is prevented from complying therewith by strikes, fire, war, civil disturbances, acts of God, laws, regulations, inability to secure material, or other causes beyond the reasonable control of said party.
15. **Notices.** Provides that all notices authorized or required between the parties and required by any of the provisions of the agreement shall be given in writing by mail or other specified means and addressed to the party to whom the notice is given at the address listed.
16. **Other provisions.** Any other provisions deemed necessary to set out the rights, duties, and obligations of the parties and efficiently and economically carry on the operations may be added to the agreement.

This list demonstrates the nature of the provisions in an operating agreement. In most operating agreements, there are additional complex provisions. Also the text of each article is considerably broader in scope and is set out in formal legal language. Several standard forms of operating agreements and unit agreements have been published. (A model form operating agreement developed by the American Association of Professional Landmen is reproduced, with permission, in Appendix 9.) However, in the case of single tract units and small pooled units, the operating agreement is usually prepared by one of the parties and is designed to fit the particular situation.

The operating agreement typically includes an exhibit on joint venture accounting procedures. The *Accounting Procedure* exhibit covers such topics as the basis of direct charges and credits to the joint account, overhead charges, disposal of equipment, basis of materials transferred on and off the property, inventories, billings, and advance payments. Over the years, the Council of Petroleum Accountants Societies (COPAS) has developed several model *Accounting Procedure Joint Operations* exhibits that are generally used, with or without modification, in joint operations. Typically when a joint operation is formed and the operating agreement is entered into, the most recently issued applicable COPAS *Accounting Procedure Joint Operations* form is adopted (with agreed-upon modifications) as an exhibit to the JOA. The several COPAS Accounting Procedure forms used over the past 30 years are found in COPAS Bulletin No. 4. The most recent, the 1995 form is reproduced in Appendix 10. The second most recent form for U.S. production was issued in 1986.

When a new COPAS bulletin is issued, it has no impact on the Accounting Procedure previously adopted as part of an operating agreement.

It should not be construed from the fact that standardized forms of operating agreements and accounting procedures are available that they are always used or that contractual rights and obligations are identical in every joint operation. On the contrary, the apparently inexhaustible variety of specific provisions presents a constant challenge to accountants and tax advisors. The most common provisions of the typical *Accounting Procedure* exhibit for joint operations are, however, reviewed in the next section of this chapter.

ACCOUNTING PROCEDURE PROVISIONS OF JOINT OPERATING AGREEMENTS

The typical accounting procedure exhibit of a joint operating agreement has two major parts: (1) the exhibit form (similar to Appendix 10) and (2) *interpretive* guidance on applying the form's provisions. The form consists of five sections summarized below:

I. **General Provisions.** The general provisions include the following topics.

1. *Definitions* of terms used in the contract, including joint property, joint operations, joint account, operator (the party designated to conduct the joint operations), nonoperators (parties to the agreement, other than the operator), parties, first-level supervisors, technical employees, personal expenses, material, and controllable material.
2. *Statements and billings.* Most agreements provide that the operator shall bill the nonoperators monthly for their shares

of charges, with billing to be made on or before the last day of the following month. Billings must identify the lease, facility, AFE, or other project and must be in appropriate detail. Usually charges and credits will be summarized by appropriate classifications of investment and expense, except that details must be given for controllable materials and for unusual charges and credits.

3. *Advances and payments.* Usually the operator is given the right to require nonoperators to advance their shares of estimated cash outlays for the succeeding month (generally referred to as a *cash call*). Each nonoperator is required to pay its portion of all bills within 15 days after receipt according to the Accounting Procedure, with interest being charged at the specified rate on late payments.
4. *Adjustments.* The nonoperators are given 24 months following the end of the calendar year in which the billing is made to take exception to billings and to claim adjustments from the operator.
5. *Audits.* Nonoperators generally have the right to audit the operator's accounts and records related to the joint account for a calendar year, with the audit to be conducted within 24 months after the close of the year. Joint Interest Audits are discussed later in this chapter.
6. *Approval by nonoperators.* The operator must properly give advance notice to nonoperators of items requiring approval or agreement. Agreement or approval of a majority (in interest owned) of nonoperators is controlling on all nonoperators.

II. **Direct Charges.** Certain items are to be charged directly to the joint operation. These usually include the following.

1. *Rents and royalties* on the property(ies).
2. *Salaries and wages* of operator's field employees directly employed on the property, salaries of first-level supervisors in the field, and salaries and wages of technical employees employed directly on the property (if the technical costs are not included in overhead rates). The charges for salaries and wages include the related costs of holiday, vacation, disability, and other allowances, as well as expenditures or

contributions imposed by governmental authority, related to the salaries and wages involved. Related personnel expenses are also direct charges.

3. *Employee benefits* applicable to direct labor costs (but usually limited to some percent of labor costs, as recommended and updated annually by COPAS).
4. *Material* purchased or furnished by the operator for use on the joint property. (Detailed provisions related to materials and equipment are discussed later in this chapter.)
5. *Transportation* of employees and material necessary for joint operations (subject to conditions).
6. *Services.* The cost of contract services, equipment, and utilities, with specified exceptions and limits.
7. *Equipment and facilities furnished by the operator.* The operator has the right to charge the joint account for use of equipment and facilities at rates commensurate with costs of ownership and operations. Detailed suggestions for bases to be used in making charges for such costs are included in Section II-7 of the Explanation part of Bulletin No. 22. In lieu of charging for actual costs, the operator may charge an amount for services equal to normal commercial rates in the area, less 20 percent.
8. *Damages and losses to joint property,* except those resulting from the operator's gross negligence or willful misconduct.
9. *Legal expenses related to joint property.* Payments to outsiders are chargeable. Special provisions are usually included covering use of the operator's own legal staff.
10. *Taxes* of all kinds on the joint property and on its operation or production.
11. *Insurance* costs on joint interest property, personnel, and operations.
12. *Other* necessary direct costs.

III. **Overhead.** Because misunderstandings may easily arise between joint interest owners over which items are to be charged directly to joint accounts, which are covered by overhead charges, and which are not chargeable to the joint account, detailed provisions relating to overhead are usually included. Salaries, wages, and personal expenses of technical employees and contract personnel may be charged directly to the joint account or may be included in the overhead rate.

As compensation for administration, supervision, office services, and warehousing costs (and, if applicable, technical personnel), the operator may charge drilling and producing activities on either (as agreed on) a *fixed-rate* basis or a *percentage* basis. Under the fixed-rate basis, a rate per well per month is set for wells being drilled, and a lower rate per well per month is charged for producing wells. Reference to Section IV of the 1995 Model Accounting Procedure Exhibit found in Appendix 10 of this book indicates the complexity of the exhibit's overhead rules. The four major subheadings of the overhead section are as follows:

1. Overhead—Drilling and Producing Operations,
2. Overhead—Major Construction,
3. Catastrophe Overhead, and
4. Amendment of Rates.

IV. **Pricing of Joint Account Material Purchases, Transfers, and Dispositions.** The operator of a joint interest frequently transfers materials and equipment from or to the operator's own warehouse or solely owned property to or from a jointly owned property. Also the operator routinely purchases materials and equipment specifically for the joint operation and may sell materials and equipment removed from the joint property. Because prices of materials and equipment change frequently and because it is not feasible for the joint owners to negotiate the price of each item transferred to or from the property, the industry, through COPAS, has developed almost universally accepted rules governing the pricing of materials and equipment purchases, transfers, and dispositions. Subsequently in this chapter use of *condition value,* found in Section IV of COPAS Bulletin No. 13, will be illustrated.

V. **Inventories.** The accounting procedure requires the operator to maintain detailed records of controllable material and to conduct periodic physical inventories.

It is a basic principle of joint operations that the venture is one of *cost sharing*. Thus, the operator is neither to make a profit nor to incur a loss merely because of holding the position as operator.

NONOPERATORS HAVE OPERATING INTERESTS

Industry terminology is inconsistent in that many holders of operating interests (i.e., working interests) are referred to as *nonoperators*. The term *nonoperator* as used in the Accounting Procedure exhibit refers to any owner of an operating interest that is not the operator of the property. As explained in Chapter Seven, a nonoperating interest is an economic interest, such as a royalty interest, that does not bear operating costs. Holders of nonoperating interests are not referred to as nonoperators.

RECORDING JOINT INTEREST TRANSACTIONS

General industry practice is for a joint interest owner to use the *proportionate consolidation* method of accounting for a joint interest in a joint venture. Under proportionate consolidation, each owner picks up its proportionate share of each asset, liability, revenue, and expense item in accordance with its own account classifications. The venture is not regarded as a separate accounting entity. Thus, no balance sheet or income statement is prepared for the entity as such. If the joint venture is in the form of a corporation (rare in the U.S.), proportionate consolidation may not be appropriate.

RECORDS OF NONOPERATOR

Nonoperators are billed monthly by the operator for their share of *charges and credits*, i.e., costs and cost adjustments, relating to the joint operation. The principal source document for the nonoperator in accounting for activities related to jointly owned properties is the monthly joint interest billing (JIB) from the operator. The billing identifies amounts with sufficient clarity and detail to enable the nonoperator to debit/credit appropriate accounts.

COPAS *Bulletin No. 1, Classifications for Use in Summary Form Billing* (revised October 1994) provides suggested categories and classifications. They are designed to adequately describe the nature of costs but do not coincide with GAAP or income tax accounting. The nonoperator must exercise judgment in classifying the costs in the chart of accounts. It is impractical for an operator to distribute all charges in exact accordance with every nonoperator's detailed classification of accounts. Nevertheless, the monthly joint interest billings almost invariably are adequate to meet the broad financial accounting classifications of companies using either the successful efforts rules or the full cost rules specified by the FASB in Oi5 and the SEC in Reg. S-X Rule 4-10 and to meet specific tax reporting requirements.

To illustrate the nonoperator's accounting treatment of a monthly billing from the operator, assume that a nonoperator received the monthly billing shown in Figure 10-1. The property is known as the N. Moore lease property. The billing covers venture costs incurred for the prior month—certain costs of N. Moore #2 as a new well and the prior month's production costs of the N. Moore #1 well. The monthly billing for this joint account contains (1) a Summary Statement and Invoice showing a summary of total charges and each owner's working interest portion, along with an invoice to the particular nonoperator receiving the statement and (2) supporting schedules by AFE enabling the nonoperator to identify the expenditures and properly account for them.

When the billing is received from the operator, it is generally first routed for approval to the appropriate engineer or department responsible for monitoring the operations. The approval process should entail a review of the JIB for reasonableness of cost amounts and cost description of the stated classifications, property, well, AFE, and month of occurrence. Following approval, the JIB is routed to the joint interest billing department where it is checked for evidence of the approval and then coded and entered into the JIB accounting system.

The nonoperator also makes entries in detailed subsidiary records. This may require judgmental classification of the billed items to accommodate the nonoperator's Chart of Accounts.

Note that account titles used to record the charges from the billing are the same as those that would be used if the properties involved were the nonoperator's solely owned property. Only the subsidiary accounts reflect the fact that the properties are jointly owned and operated.

The nonoperator charges payments made to the operator to Vouchers Payable. Advances may be charged either to the payable account or to a prepayment account.

Figure 10-1: Operator Billing to Nonoperators

BIG OIL USA, INC.
P.O. BOX 12345, DENTON, TX 76201

COUNTRY SERVICE COMPANY
15467 EAST 107TH AVENUE
HOUSTON, TX 770461

INVOICE NO.: 0523174
INVOICE DATE: MAY 24, 2000
TERM: NET 30 UPON RECEIPT
MONTH: APRIL 2000
PROPERTY: N. MOORE LEASE

SUMMARY STATEMENT AND INVOICE

OWNER NO.	OWNER NAME	WORKING INTEREST	AMOUNT
1123500	ABC OIL	.0447897	$ 24,033.14
1118600	CORONADO HILLS PARTNERS	.0635633	34,106.62
5117300	COUGAR PETROLEUM	.0153747	8,249.72
2954800	WILL B. SMITH	.0226632	12,160.56
1431400	COUNTRY SERVICE COMPANY	.0547563	29,380.99
0488500	J.B. JONES	.0258106	13,849.38
8224400	BDF OIL & GAS	.3833124	205,676.74
0000001	BIG OIL USA, INC.	.3897298	209,120.16
		1.0000000	
Total Current Period Charges to Joint Account			$536,577.31

TO INVOICE YOU FOR:

Drilling and Development Charges	$ 29,102.52
Lease Operating Expenses	278.47
Total Current Period Charges	29,380.99
Previous Balance Carried Forward	0
Total Due	$ 29,380.99

REMITTANCE INSTRUCTIONS
Please reference the above Invoice Number and mail payment to:
Big Oil USA, Inc.
P.O. Box 12345
Denton, TX 76201

Figure 10-1, continued

BIG OIL USA, INC.
P.O. BOX 12345, DENTON, TX 76201

COUNTRY SERVICE COMPANY	INVOICE NO.: 0523174
15467 EAST 107TH AVENUE	INVOICE DATE: MAY 24, 2000
HOUSTON, TX 77046	TERM: NET 15 UPON RECEIPT
PROPERTY: N. Moore Lease	MONTH: APRIL 2000
WELL: N. Moore #2	AFE No.: 102

Drilling and Development Charges:

S/L	DESCRIPTION	AMOUNT	TOTAL
104	Tubing	$147,780.21*	
105	Wellhead Assembly	764.88	
115	Misc. Non-Cont. Surface Well Material	684.79	
122	Production & Other Lease Facilities	14,111.02*	
133	Installation Cost	4,245.70	
244	Permits, Site Prep & Cleanup	8,638.74	
248	Other Contract Services	116.25	
249	Contract Drilling	301,903.89	
251	Direct Supervision	7,870.42	
255	Bits	(1,297.06)	
267	Equipment Rentals	3,449.50	
268	Small Tools & Supplies	206.90	
269	Transportation Land	6,156.29	
273	Communications	177.66	
275	Testing, Drafting & Inspection	22,083.03	
277	Perforating	8,280.20	
280	Drilling Overhead Charge	5,000.00	
283	Loss & Damage	1,319.23	
	Total Drilling and Development Charges		$531,491.65

*Controllable material detail is attached.[20]

[20]Controllable material refers to items that can be reasonably controlled and accounted for by periodically taking a physical inventory of the items. COPAS Bulletin No. 6 provides a list of controllable material.

Figure 10-1, continued

BIG OIL USA, INC.
P.O. BOX 12345, DENTON, TX 76201

COUNTRY SERVICE COMPANY	INVOICE NO.: 0523174
15467 EAST 107TH AVENUE	INVOICE DATE: MAY 24, 2000
HOUSTON, TX 77046	TERM: NET 15 UPON RECEIPT
PROPERTY: N. Moore Lease	MONTH: APRIL 2000
WELL: N. Moore #2	AFE No.: 102

Controllable Material Detail:

ACCOUNTING CODE	DESCRIPTION	AMOUNT	TOTAL
27-2631-102-104	MT60549		
	13,005.8" (411 Jts.) 2 7/8 6.5# L-80 AB Mod R-2		
	Tubing, Condition A		$147,780,21
27-2631-102-122	MO208		
	30.0 ea.-2150# WN Flange w/std bore	$ 331.68	
	7.0 ea.-21N #143 Rockwell Plug Valve	419.96	
	20.0 ea.-3150# RF WN Flange w/std bore	276.16	
	7.0 ea.-31N #143 Rockwell Plug Valve	690.23	
	4.0 ea.-41N #143 Rockwell Plug Valve	536.98	
	332.0 ea.-5/8 x 3 ½ BO7 Ht. Alloy Std. w/2	367.73	
	270.7 ft. – Ft. 3 in sch-40 A-53-B SMLS Pipe PE	1,513.48	
	1.0 ea.-4 std. weld cross	243.28	
	5.0 ea.-3 Fig 100 FE #021027-15-BS-285	1,805.00	
	1.0 ea.-2 Fig 100 FE #031027-F-15-BS	220.00	
	139.0 ft.-2 sch 40 SMLS Line Pipe	625.29	
	3.0 ea-4 PE BLK Pipe x 21'	415.80	
	17.0 ea-2 PE BLK Pipe x 21'	817.08	
	3.0 ea-4 wafer butterfly valve demco	323.97	
	Miscellaneous Non-Controllable Items	2,558.34	
		11,144.98	
	MO266		
	30.0 ea.-2150# WN Flange w/std bore	144.66	
	MO310		
	Miscellaneous Non-Controllable Items	2,631.00	
	MO443		
	Miscellaneous Non-Controllable Items	141.60	
	MO444		
	Miscellaneous Non-Controllable Items	48.78	
Total Production and Other Lease Facilities			$14,111.02

Figure 10-1, continued

BIG OIL USA, INC.
P.O. BOX 12345, DENTON, TX 76201

COUNTRY SERVICE COMPANY	INVOICE NO.: 0523174
15467 EAST 107TH AVENUE	INVOICE DATE: MAY 24, 2000
HOUSTON, TX 77046	TERM: NET 15 UPON RECEIPT
PROPERTY: N. Moore Lease	MONTH: APRIL 2000
WELL: N. Moore #1	AFE No.: N/A

Lease Operating Expense:

S/L	DESCRIPTION	AMOUNT	TOTAL
120	Contract Labor	$2,903.61	
121	Rig Services	406.71	
125	Gas Handling	6.81	
128	Salt Water Disposal	375.75	
140	Chemicals	44.72	
141	Small Tools & Supplies	55.34	
143	Automotive Expense	198.36	
170	Telephone & Telegraph	53.50	
180	Employee Travel & Gen Exp	68.13	
800	General Services	112.08	
824	Area Expense	510.65	
880	Production Overhead	350.00	
	Total Lease Operating Expense		$5,085.66

The journal entry made by Country Service Company, which owns a .0547563 interest in the N. Moore lease, to record the billing illustrated in Figure 10-1 would be:

241	Work In Progress—Intangible Costs of Wells and Related Development—N. Moore #2 [.0547563 x (Items 133-283)]	20,158.58	
243	Work In Progress—Tangible Costs of Wells and Related Development—N. Moore #2 [.0547563 x (Items 104-122)]	8,943.94	
710	Lease Operating Expenses—N. Moore #1 (.0547563 x $5,085.66)	278.47	
	301 Vouchers Payable		29,380.99

To record receipt of joint interest billing for April for N. Moore wells.

RECORDS OF THE OPERATOR

Since the operating agreement requires that, unless otherwise specifically provided, the operator shall pay all costs and expenses incurred and shall charge each nonoperator with that party's proportionate share as set out in the operating agreement and on the basis provided in the accounting procedure, the operator's accounting system must be designed to properly accumulate and classify expenditures to be billed to the nonoperators. With the advent of the computer age, almost every oil and gas company uses some type of computerized system or software package to facilitate in the classification, accumulation, and billing processes. Either of two procedures may be used to accumulate costs and bill nonoperators.

Charging Costs to Joint Interest Accounts

The most commonly used procedure is to identify each charge or credit with the individual joint operating agreement, appropriately classify the item by account number, and record it to the property by way of some identifying number at the 100 percent gross (8/8ths) amount of the vendor invoice. Appropriate subsidiary records for each type (by way of account numbers) of charge or credit for each joint operation are maintained. These subsidiary accounts usually agree with the operator's Work In Progress, Wells and Related Facilities, and Lease Operating Expense subsidiary ledgers. The property identifying number contains the appropriate computerized billing information to bill each working interest owner for that owner's correct share of charges and credits. For example, if Big Oil USA, operator of the N. Moore #2, received a statement for $301,903.89 from the contract driller of N. Moore #2, the entry made by Big Oil might be:

241 Work In Progress—Intangible Costs of Wells and Related Development, N. Moore #2	301,903.89	
301 Vouchers Payable		301,903.89

To record receipt of statement from drilling contractor on N. Moore #2.

All the charges for a particular property accumulate during the month at the 100 percent gross amounts under the property identifying number and are classified by account type. At the end of the month, the charges and credits made to the accounts are processed by the JIB system, and the appropriate amounts to be charged to the working interest owners are removed (or *cut-back*) from the operator's accounts and charged to the receivable account. After this process, JIBs are prepared to invoice the nonoperators for their share of costs. The operator's proportionate share of each cost is *netted* in the appropriate account in the operator's financial records in accordance with the operator's account classification, while the nonoperators share of total charges is charged to Accounts Receivable or a similarly titled account. Based on the joint interest billing percentages shown in Figure 10-1, the operator's joint interest billing system would make the following entry at the end of April relating to the contract drilling costs on N. Moore #2.

123	Accounts Receivable—Joint Interest Billings	184,242.95	
	241 Work In Progress, N. Moore #2		184,242.95

To record the receivable from the nonoperators for their share of N. Moore #2 drilling costs.

Since the joint interest billing system is processed at the end of each month, only the operator's interest and a receivable from the other working interest owners will appear in the monthly financial statements. Since during the month costs are accumulated for each joint activity, the detailed records relating to these ventures form a Joint Interest Ledger.

Some companies use a variation of the above method, in which the joint interest entries are processed on a daily basis; however, the joint interest billings are still sent out at the end of the month.

Allocating Each Transaction to each Joint Interest's Accounts

Another approach used by many operators to record joint venture transactions is to analyze each individual transaction prior to recording it. That portion applicable to nonoperators will be immediately charged to Accounts Receivable—Joint Interest, while that portion applicable to the operator will be charged to the operator's usual asset, liability, expense, or revenue accounts.

For example, if this method had been used by Big Oil USA, operator and owner of .3897298 of the working interest in the N. Moore lease, and Big Oil had received a statement for $301,903.89 from the drilling contractor on Well # 2, the entry would have been:

241	Work In Progress—Intangible Costs of Wells and Related Development	117,660.94	
123	Accounts Receivable—Joint Interest Billings (and detailed accounts for nonoperators)	184,242.95	
	301 Vouchers Payable		301,903.89

To record receipt of statement from drilling contractor on N. Moore #2.

MATERIAL TRANSFERS

Because problems have traditionally arisen over the proper accounting for materials and equipment transferred by the operator to and from jointly owned properties, COPAS has developed special rules to help alleviate the problems.

Under proportionate consolidation, each owner records that owner's share of equipment included in Tangible Costs of Wells and Related Development. Since equipment may be moved between the joint venture's well sites and the operator's warehouses and equipment yards, the recording of such transfers to and from joint interest properties becomes an important consideration.

When an operator transfers used material or equipment to a joint property, the transfer price should reflect an approximate current market price. The 1995 COPAS Accounting Procedure lists several pricing methodologies that may assist an operator in obtaining generic material and equipment prices when recording a transfer transaction. One of those methods is a database, developed by COPAS, *Computerized Equipment Pricing System* (CEPS), that calculates a generic price for each piece of material or equipment from a published base price list that is updated annually by a *historical price multiplier* (HPM). The 1995 Accounting Procedure states that the following methods may be used provided that the pricing is equivalent to current market value:

- CEPS,
- manually applying the HPM to a published material and equipment price listing,
- vendors' quotes,
- historical purchase prices, and
- mutual agreement of the transfer prices by the parties involved.

TRANSFER FROM WAREHOUSE TO JOINT ACCOUNT

When equipment is transferred from the operator's wholly owned warehouse inventory to a jointly owned property, it is deemed sold to the joint venture at a *condition value* defined in the Accounting Procedures exhibit of the venture's joint operating agreement. For example, assume that an item of equipment is carried in the operator's warehouse inventory account at $20,000. The current price of a new asset is $32,000, and the equipment is *Condition B* (a term explained on page 21 of Appendix 10) to be valued at 75 percent of current new cost. The equipment is transferred to a joint interest property, No. 12103J. The operator owns three-fourths of the working interest. Since the equipment is Condition B, the nonoperator owner is to be charged $6,000 ($32,000 x .75 x 1/4) for the one-fourth interest that is, in effect, being sold to the nonoperator. Since that one-fourth interest is being carried in the operator's warehouse inventory at a cost of $5,000 (1/4 x $20,000), a gain has been realized. However, no gain is realized on the three-fourths interest belonging to the operator because no sale to an outsider has taken place. Thus, the ultimate result of the transfer, ignoring transportation, must be the following:

123	Accounts Receivable—Joint Interest Billings (1/4 x .75 x $32,000)	6,000	
233	Tangible Costs of Wells and Related Development (3/4 x $20,000)	15,000	
	132 Warehouse Inventory		20,000
	630 Other Income		1,000

To record transfer of equipment to jointly owned property.

Various other procedures may, of course, be used to ensure that profit or loss is recognized on the share of equipment sold to the nonoperator but that no profit is recorded on the share retained by the operator.

The freight costs, along with installation costs, would be charged directly to the joint interest and should be treated as part of the equipment's cost by all parties.

Transfer from Wholly Owned to Jointly Owned Lease

Similar procedures would be appropriate for equipment transfers between leases. For example, assume that an item of equipment with an original cost of $20,000 is transferred from a Lease 18610 (a wholly owned lease) to Lease 18205 in which the operator owns one-fourth of the working interest. The equipment is Condition Value B to be charged to Lease 18205 at $24,000. Three-fourths of the asset is deemed to have been sold for $18,000 (3/4 x $24,000). However, in accordance with Reg. S-X Rule 4-10 and Oi5, no gain or loss is recognized on the sale or retirement of wells or equipment under full cost or under the successful efforts method until the last well is abandoned. Instead, all proceeds should be credited to the asset account, whereas in the prior example gain could be recognized for gain on sale of equipment from operator's inventory. Preferably, if the asset's original cost is known, its cost should be removed from the asset cost account and the accumulated amortization account, if need be, adjusted to defer the gain or loss. The *ultimate result* of this entry should be:

123	Accounts Receivable—Joint Interest Billings	18,000	
233	Tangible Costs of Wells and Development—Lease 18205	6,000	
	234 Accumulated Amortization of Tangible Costs of Wells and Development—Lease 18610		4,000
	233 Tangible Costs of Wells and Development—Lease 18610		20,000

To record transfer of equipment from wholly owned lease to jointly owned lease.

Alternatively, the entry could debit account 233 for $5,000 and credit account 234 for $4,000 so as to record Lease 18205 equipment cost at 25 percent of the $20,000 original cost, rather than 25 percent of the $24,000.

REMOVAL OF ASSETS FROM JOINTLY OWNED PROPERTY

A third example illustrates the treatment of assets removed from jointly owned properties and transferred to the operator's warehouse. Assume that the operator removes an asset originally installed new at a cost of $20,000 from Lease 06203J in which the operator owns one-fourth of the working interest and transfers the asset to the operator's warehouse where it is to be reconditioned for use on the operator's wholly owned Lease 17304. At the time of removal, a new identical asset would cost $32,000. The removed asset's condition value is *C* (50 percent of current new cost). In effect the operator has purchased three-fourths of the equipment from the nonoperator for $12,000 and has removed one-fourth of the equipment (cost $5,000) with a salvage value of $4,000 (1/4 x $16,000). The *ultimate effect* of the entry to record the transfer should be:

132	Warehouse Inventory (.50 x $32,000)	16,000	
234	Accumulated Amortization of Tangible Costs of Wells and Development—Lease 06203J	1,000	
	123 Accounts Receivable—Joint Interest Billings		12,000
	233 Tangible Costs of Wells and Development—Lease 06203J		5,000

To record transfer of equipment from jointly owned lease to operator's warehouse.

Note that, in effect, the Accumulated Amortization account is being charged for a residual amount determined by the entries in the other accounts since no gain or loss is to be recognized.

TRANSFER BETWEEN TWO JOINTLY OWNED LEASES

Equipment may also be transferred by the operator between two jointly owned leases. For example, assume that a piece of equipment with an original cost of $20,000 is transferred to Lease 10723J, which is owned one-half by the operator and one-half by Little Oil Company. The equipment is transferred at a $16,000 condition value of 75 percent of the current price of $21,333 from Lease 10792J, which is three-fourths owned by the operator and one-fourth owned by Danielson Oil Company.

This situation creates a challenging problem, to which there is no completely satisfactory solution. The most common approach is to assume that, in effect, one-fourth of the equipment is being purchased for $4,000 from the joint owner of the lease on which the asset was originally located and that the remaining three-fourths with a *condition value* of $12,000 is being removed from the lease (with no gain or loss recognized). Then, in effect, one-half of the equipment has been sold to the joint owners on the new lease for condition value and one-half has been transferred to the operator's accounts relating to the new location. The ultimate effects of this entry are:

123	Accounts Receivable—Joint Interest Billings, Little Oil (1/2 x $16,000)	8,000
233	Tangible Costs of Wells and Development—Lease 10723J (1/2 x $16,000)	8,000

234 Accumulated Amortization of Tangible Costs of Wells and Development—Lease 10792J ($20,000 - $16,000) x 75%	3,000	
123 Accounts Receivable—Joint Interest Billings, Danielson Oil (1/4 x $16,000)		4,000
233 Tangible Costs of Wells and Development—Lease 10792J (3/4 x $20,000)		15,000

To record transfer of assets between joint-interest properties.

JOINT INTEREST AUDITS

After joint interest billings are received, approved, and processed, the nonoperator can gain further assurance on the accuracy of billed charges by examining the operator's internal records supporting the billings. Such examinations, called joint interest audits, are allowed and governed by the Accounting Procedure exhibit of the JOA. COPAS Bulletin No. 3 provides additional guidance on joint interest audit protocol and procedures. Under the terms of most JOAs, the audit period is defined as the current year and the prior two years. Generally, the nonoperator with the largest working interest initiates the audit, leads the audit, contacts the operator, and plans the audit.

If an audit is needed, the nonoperator assigns an experienced person within or outside the company to act as lead auditor. He or she will alert the operator of the desire to audit the records, request the necessary documents, and decide on the timing of the audit. The auditor prepares a confirmation letter to the operator providing (1) the name and addresses of all working interest owners, (2) the properties to be covered in the audit, (3) the on-site visitation dates and estimated number of auditors who will be present, (4) the time period of activity that will be audited, (5) arrangements to access pertinent original records, and (6) a description of records requested in advance. Operator's original records should include the company's Chart of Accounts, organization charts, field schematic, drilling contracts; drilling permits; daily drilling, tour, cementing, completion, mud, chemical, bit usage, and plug and abandon reports; casing specifications; journal vouchers with backup; material transfers; and all pertinent records from the operations department.

The lead auditor should then prepare a letter to the nonoperators informing them of the operator's consent to the audit; giving them the pertinent information such as the date of the audit, the properties, the estimated cost, and length of time to complete the audit; and asking them if they agree to the audit and if they will share the costs or send their own auditors. This *ballot letter* should also include the date by which it should be returned to the lead auditor.

In planning the audit, the lead auditor should do a risk assessment. Have there been previous associations with the operator? If not, what is the reputation of the operator? Has a previous audit been completed? What were the results? How many properties should be audited? What types of expenditures should be audited? What amount of billed expenditure is too small to audit? Has the lead auditor's management requested specific wells for the audit?

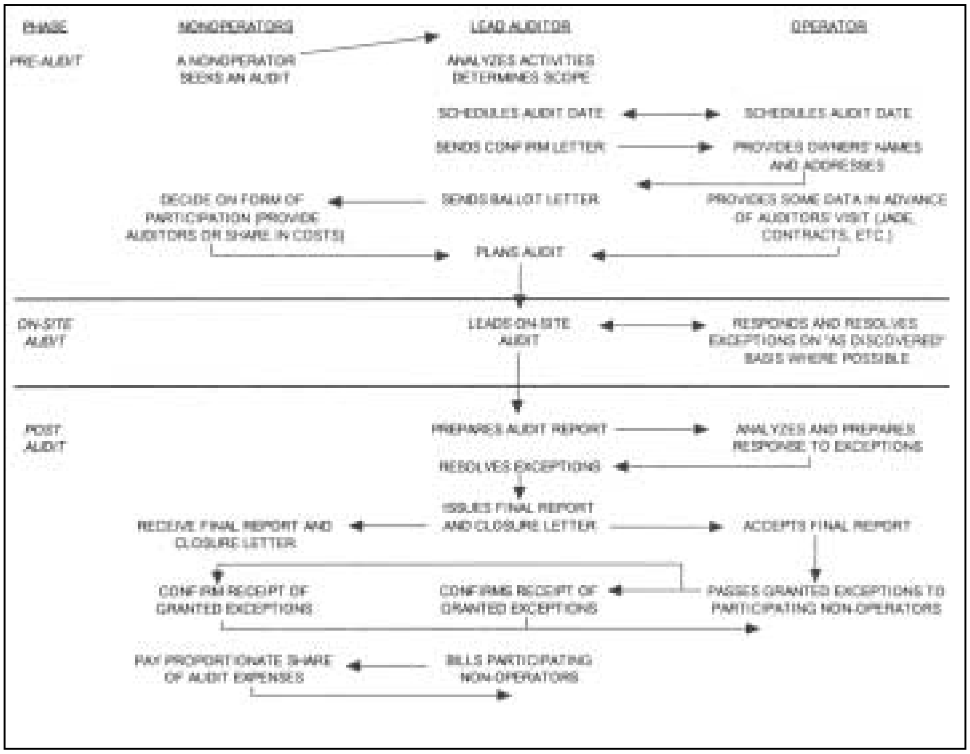
The lead auditor is responsible for preparation of the audit program, coordination and supervision of the audit, and communications between the operator and other nonoperators on audit findings, the operator's response, follow-up, billing audit costs, and any other issues.

The lead auditor should also ensure that as much work as possible be done up front before reaching the operator's office, such as preparing ahead by reading the daily drilling reports to get a history of the properties, reading through the information contained in any previous audit reports and files, and preparing any lead schedules with information from the operations department or Joint Audit Data Exchange (JADE) data, an electronic file of the cost detail transactions related to all the requested properties to be audited.

After the actual audit is completed, the lead auditor presents the findings to the operator, prepares the audit report, identifies the exceptions (either for or against the operator), distributes the audit report to the members of the audit team and to all the nonoperators and the operator, follows up on resolution of open issues, and writes a final closure letter.

General steps for a joint interest audit are summarized in Figure 10-2. COPAS Bulletin No. 3 provides example forms of the required letters and reports.

Figure 10-2: General Steps for a Joint Interest Audit



ELECTRONIC DATA INTERCHANGE (EDI)

Joint interest operations require that oil and gas companies exchange a vast quantity of operating and accounting data. In the early history of the industry, much of this data was compiled, classified, and disseminated by manual methods. The advent of the computer permitted individual companies to develop software programs for accumulating data and preparing reports. However, companies receiving the data would have to enter the information in their accounting and data systems. Later, some companies adopted the practice of providing computer tapes to those to whom they were supplying information.

Very recently, the concept of electronic data interchange (EDI) has greatly simplified information transmittal and receipt in joint operations accounting and in accounting for other transactions between companies, for example, in the exchange of petroleum products.

Largely through the initiative of members of COPAS, a number of computer programs have been developed to facilitate the accumulation, transmittal, and receipt of data. Perhaps the General Electric Information Services electronic data exchange systems are the best known of these programs. Under this program, data are transmitted by the GE Information Services Network. Each company retains its in-house coding system. Data to be transferred to other companies are converted to standard codes and formats for transmission. At the receiving company, the data are received directly into the company's computer system and are converted from the standard format and coding into the company's own in-house house codes and formats.

Among the most important parts of this data exchange program are the following:

1. **CODE (Crude Oil Data Exchange).** This system furnishes run ticket and run statement information on the receipt and delivery of crude oil through carrier pipelines.

2. **CDEX (Check Stub Data Exchange).** This program automates the collection and distribution of clerk detail information on jointly-owned oil and gas properties.

3. **GRADE (Gas Revenue Accounting Data Exchange).** GRADE provides information on natural gas/NGL metered volumes, allocated volumes, test data, and plant settlement data.

4. **PETROEX (Petroleum Product Exchange System).** The PETROEX system provides bills of lading and bulk custody information on furnished product exchange transactions.

5. **RECON (The Exchange Reconciliation System).** This system produces a record of unmatched exchange transactions on a contract and a product basis.

6. **TABS (Terminal Administration and Billing System).** The TABS program provides credit and product authorization at exchange terminals and captures bill of lading information.

7. **JADE (Joint Audit Data Exchange).** The JADE system provides information needed for review and verification of a joint venture operator's source documents. The system helps reduce the audit time required by auditors and the operator's support staff.

8. **JIBE (Joint Interest Billing Exchange).** The JIBE system provides the capability to transmit the monthly joint interest billing statements and invoices electronically to other working interest owners.

E-COMMERCE

In 1999 petroleum companies used the internet primarily for internal communications and knowledge sharing. In the coming decade, we can expect the petroleum industry to make greater use of the internet for procurement of goods and services, and in turn, for joint interest billing of those procurements. BP Amoco reported in 1999 an e-procurement plan to use the internet for 50% of its procurement transactions for a savings of over $200 million per year.

Chapter Eleven

PRODUCTION AND VOLUME MEASUREMENT

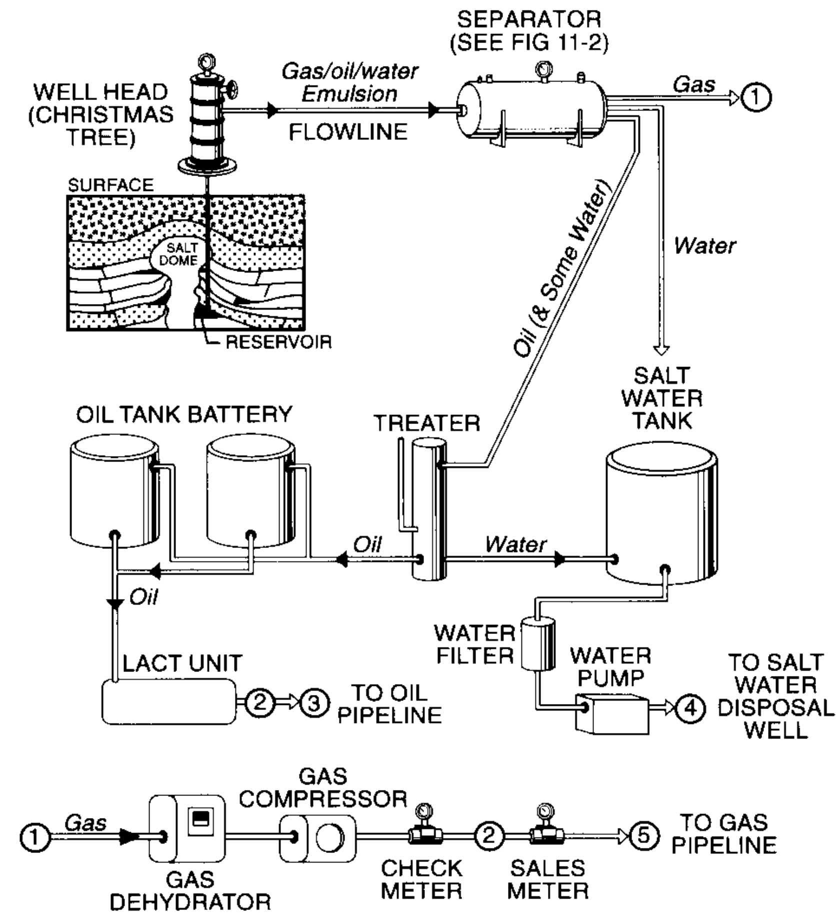
The objective of oil and gas operations is to produce and sell oil and gas for a profit. Therefore, the procedures used to measure, market, and finally account for the product produced and sold are important and must be understood by the accountant. This chapter briefly explains (1) equipment and processes used to produce, move, treat, and handle oil and gas in preparing such products for market; (2) the various arrangements for processing gas; (3) how gas may be reinjected, rather than being immediately sold; and (4) how volumes produced may be stored in above or underground facilities. This chapter also focuses on measuring the corresponding volumes of crude oil (including condensate), nonprocessed natural gas from the field, natural gas liquids, and residue gas produced during gas processing. The reader will be introduced to many new industry terms in this chapter and is requested to keep in mind that terms may vary slightly in common usage between petroleum accountants, engineers, and other industry groups.

Chapter Twelve discusses the different marketing issues for crude oil and natural gas. Chapter Thirteen illustrates the accounting entries for recording oil and gas sales and the issues encountered.

PLACING THE WELL ON PRODUCTION

After a well is completed (described in Chapter Eight), it is *placed on production* by installing surface equipment that will (1) collect and gather the produced emulsion of natural gas, oil, and water from the well; (2) separate the gas, oil, and water; (3) *treat* the gas and oil as necessary to minimize any remaining impurities and bring the gas and oil to a marketable condition; (4) store the oil briefly prior to sale (which further removes impurities); (5) measure the volumes produced and sold; and (6) facilitate removal of the gas, oil, and water. Natural gas is typically removed by pipelines; oil is removed by pipelines, barges, or trucks; and produced water may be treated and injected into underground reservoirs using commercial salt water disposal wells or, in the case of some offshore wells, into the ocean. Figure 11-1 illustrates some typical surface equipment used for oil and gas production.

Figure 11-1: Schematic of Lease Production Facilities



(2) = The point of movement when title transfers at the lease as the oil or gas is sold.

(3) = The oil is removed by pipeline, barge, or tanker. The oil may also be removed by truck without the use of a Lease Automatic Custody Transfer unit.

(4) = The water is pumped underground using a salt water disposal well.

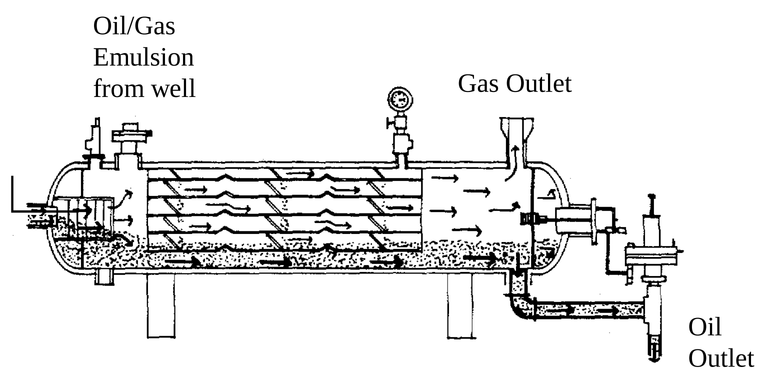
(5) = The gas is sent into a gas gathering system or gas pipeline (and perhaps on to a gas processing plant for removal of NGL).

To collect and gather the gas, oil, and water produced in a field, the E&P company connects the wellheads to pipes called *flow lines*, usually buried beneath the surface, that lead to various surface equipment. The collection of flow lines is often called a *gathering system* or *network*. However, gathering system normally refers to any system of pipes over a wide area that gathers gas from many wells and fields for delivery to a major gas pipeline or a gas processing plant. Sometimes the term *gathering system* will refer to all of the surface equipment and flow lines that serve to gather and prepare the gas and oil for sale from the lease.

Even though a well may be classified as a gas well or as an oil well, few reservoirs produce only one product, and the individual products may need to be separated and treated to remove impurities (such as sediment and water or water vapor) before the product is removed from the field. Most pipelines and refineries require that the content of crude oil contain less than one percent of *basic sediment and water (BS&W)* and that natural gas have no more than seven lbs. of water vapor per mmcf.

The oil and gas mixture may be directed through an enclosed steel, cylindrical, or spherical piece of equipment called a *separator* that uses gravity, and sometimes centrifugal force, to separate the gas from the liquids. A horizontal separator is illustrated in Figure 11-2. The oil and gas mixture flows through the separator in a process that generally takes from one to six minutes depending on the density of the oil. The gas, which is lighter than the liquids, escapes through an outlet at the top of the separator. The liquids, being heavier, escape through lower outlets. A separator that separates the gas from the liquids is called a two-phase separator; a three-phase separator separates gas, water, and oil.

Figure 11-2: A Horizontal Two-Phase Separator



Note: A Three-Phase Separator (not shown) separates gas, oil, and water.

When oil droplets are trapped and suspended in water, called *oil-in-water emulsion*, or water-in-oil, called *reverse emulsion*, the mixture is *treated* with demulsifing chemicals and heat to assist gravity in separating the products in a more sophisticated separator referred to as a *heater treater*. Another type of treater is the *electrostatic treater,* which uses an electric charge instead of heat to cause water to settle out of the oil. Treaters may also serve to separate any gas trapped in the emulsion.

Stage separation refers to the process of running this mixture through the separators before selling the products. Three-stage and four-stage separation refers to the number of times the mixture is run through separators, with decreasing levels of pressure applied to aid in maximizing product recovery.

The crude oil is moved through the flowline and stored in large steel storage tanks, or *stock tanks*, until sold. The stock tank is counted as one of the stages in three-stage and four-stage separation as any remaining BS&W will settle to the bottom of the tank.

In some cases, depending on the crude oil produced, a significant amount of natural gas separates from the crude oil in the stock tanks, despite several stages of prior separation. The stock tanks may be connected to a *vapor recovery system* that collects the gas for sale, lease use, or flaring. If there is a sufficient quantity of natural gas to justify the cost of compressing the gas for movement to a gas pipeline, the gas will be sold. Lease use gas refers to the portion of gas used on the lease as fuel for heater treaters, dehydration units, or gas compressors. Typically, the last stage of separation yields a small quantity of gas that is not economical to compress and sell. This small amount of gas is typically flared if there is enough volume to maintain a constant flame or, if not, vented into the atmosphere, depending on state and federal resource conservation and air pollution regulations.

Water and impurities must be removed from the natural gas before the gas will be accepted by the pipeline. *Dehydration* is the process of removing the water vapor from the gas by heating, adding drying agents, adding antifreeze agents, expanding the gas and refrigerating it with heat exchangers, or using a glycol dehydrator that works on the principle of absorption and pressure. *Gas conditioning* (or *sweetening*) is the process of removing impurities, such as CO_2 and H_2S, from the gas by using additives, heat, and filtering methods. The processes used are dependent on the composition of the gas.

Each lease normally has two or more stock tanks often capable of holding several days of oil production and connected by flow lines (referred to as a *tank battery*) and equipped with inlets and valves for controlling the flow of the oil into and between the tanks. While the oil that has been processed through the separators is filling one stock tank, a valve will be closed to isolate the other tank so that the oil can be measured and drained into a truck, barge, or a pipeline. The oil is removed from the stock tanks through an outlet called the sales line, approximately one-foot from the bottom of the tank. Sediment and water will settle to the bottom of the tank, so placing the *sales line* one foot above the bottom of the tank will ensure that the purchaser or *transporter* receives only sales-quality oil. Occasionally, the residue below the sales line, referred to as *tank bottoms* or *bottom oil*, will be drained and reprocessed through the separators. Metal seals with recorded serial numbers are used to close the outlet valve on the sales line and are tracked by the lease operator and oil purchaser to safeguard against unauthorized movement of oil from the stock tanks.

OIL STORAGE

The crude oil inventory held by most companies generally consists of insignificant unsold oil in the field tank battery. U.S. demand for crude oil substantially exceeds U.S. production capacity throughout the year and minimizes the need for storage in the field. As mentioned earlier in this chapter, the tank battery may consist of two or more tanks. Tank capacity varies with the field's early production rates and its remoteness from pipelines. The change in inventory volume from quarter to quarter does not vary significantly. Hence, as discussed in Chapter Thirteen, many companies do not reflect crude oil inventory on their balance sheets.

In the U.S., the only substantial underground crude oil storage is the Strategic Petroleum Reserve (SPR). In 1977, the U.S. government began storing crude oil in underground leached salt caverns in the Gulf Coast area, Michigan, and New York to prevent a major supply disruption, such as an abrupt decrease in foreign imports. Approximately 565 million barrels of crude oil were in storage as of the end of 1999, as reported on the SPR's website.

REMOVING THE PRODUCTS FROM THE LEASE

Crude oil may be moved from the lease by pipeline, truck, barge, or rail tank car to a refinery or to an intermediate oil purchaser. For oil delivered into a pipeline, the product may be measured by a *lease automatic custody transfer unit* (LACT unit), which automatically measures, samples, and tests oil and either returns it for additional treatment or sends it into the pipeline. If a LACT unit is not used, then operations are manually handled by gauging stock tanks, manually testing and measuring samples, and manually calculating volumes delivered into the truck, barge, tank car, or pipeline.

Natural gas is moved from the lease through a gas meter, used for measurement, to a regional gas gathering system or sometimes directly into an intrastate or interstate gas pipeline. The *gas meter* is typically owned by the gas purchaser and is referred to as the *sales meter*. It is common practice for the lease operator to install another meter, called a *check meter*, on the pipeline immediately before the sales meter. The accuracy and dependability of gas meters are not as good as the meters used for crude oil, and they must be recalibrated frequently. The lease operator compares the volumes from the check meter with those of the sales meter. The gas sales contract usually specifies that if the difference is greater than typically two to five percent, the lease operator can demand that the sales meter be recalibrated.

If necessary or economically profitable, gas in the gathering system or the pipeline will be sent to a gas processing plant for removal of *natural gas liquids* (NGLs) such as ethane, propane, butane, and natural gasolines. Gas processing is described in more detail later in the chapter.

Gas Compression

Gas moves through a pipeline by pressure boosted by *gas compressors*, equipment that compresses the gas, which increases the gas pressure to push the gas through the pipeline. Gas compressors might be powered by gas turbines, steam turbines, electric motors, or gasoline engines. The gas compressors are located in *compressor stations* which might be placed every 40 to 50 miles along the pipeline system.

If the gas reservoir pressure is sufficiently high, it can push the produced gas into the gas gathering or gas pipeline system. If not, gas compressor(s) may be added at the lease site to increase the pressure of the produced gas to push it into the pipeline system and remove the gas from the lease. As gas is produced from a reservoir, reservoir pressure declines. Gas compressors may be added, as needed, in the later stages of the field's productive life.

GAS INJECTION

Gas produced from a reservoir may be reinjected into the reservoir when the reinjection will increase the ultimate recovery of oil or condensate or when there is no economic market for gas sales. Regulatory authorities will not generally permit the flaring of gas. Reinjection typically improves production of the more valuable oil or condensate, and the gas may be produced and sold at some future time if economics allow.[21]

For example, the substantial volumes of gas produced on the North Slope of Alaska cannot be economically transported to markets outside Alaska. They are classified as unproved gas reserves, and are reinjected back into the producing reservoir after being processed to remove condensate and NGL.

Gas Injection for Pressure Maintenance in Oil Reservoirs

In some situations the ultimate recovery of oil can be increased by maintaining the reservoir pressure above the *bubble point*, i.e., a pressure at (or below) which gas bubbles out of the liquid. At pressures above the bubble point, all gas molecules stay dissolved and in solution with the crude oil. At pressures below the bubble point, gas begins to break out of the solution as gas bubbles form and begin to rise to the highest part of the reservoir where a secondary gas cap may be formed. As the gas escapes, the viscosity of the crude oil increases and the mobility of the oil decreases, causing ultimate oil recovery to decrease.

Large capital expenditures are required to install the equipment necessary for reinjection of the gas, and revenues from sale of the gas are

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[21]Oil recovery methods may be grouped into two broad classifications: primary recovery and enhanced recovery, as discussed in Chapter Thirty-One. An inexact definition of primary recovery is that it embraces all production when the reservoir's natural drive mechanism (water drive, dissolved gas drive, gas cap drive, and in limited cases, gravity) is the only source of energy causing the reservoir contents to flow into the well bore. Thus, production from free-flowing wells, wells using artificial gas lift (lifting fluids up the well, not into the well), and wells producing oil lifted by pump would be considered as primary production if the oil flows into the well under the natural pressure and conditions of the reservoir. Enhanced recovery represents the production that results from an artificial reservoir drive, such as water or gas injected into the reservoir (not into the producing well) to push the reservoir fluids into the well bore.

delayed until most of the recoverable oil reserves have been produced. Data from geologists, engineers, and financial analysts can be used to determine the merits of a gas injection project to increase ultimate oil recovery.

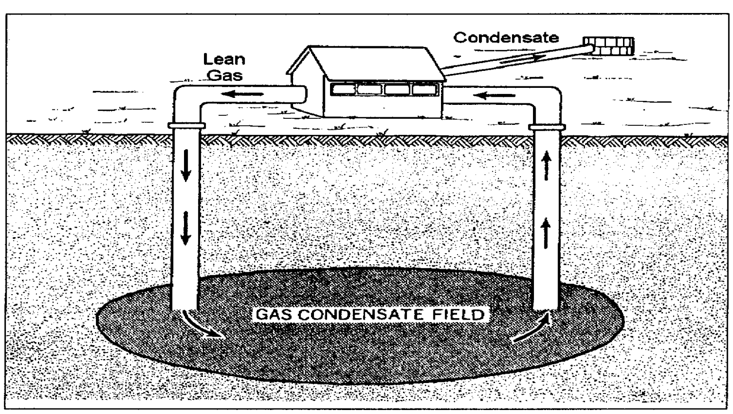
Gas Injection for Pressure Maintenance in Gas Condensate Reservoirs

In most cases the ultimate recovery of condensate can be increased by maintaining the reservoir pressure above the *dew point*. At pressures above the dew point, all gas and condensate exist as a single solution. At pressures below the dew point, liquid drops of condensate begin to form and fall out of the solution. Some of these drops wet the rock surface and stick to the surface, while others fill the pore space around each wellbore. Since liquid condensate does not flow through the reservoir rock as easily as gas, a drop in reservoir pressure below the dew point both decreases the amount of condensate that can flow to the wellbore and restricts the flow of gas through the reservoir. Reservoirs producing with these characteristics are often called *retrograde condensate reservoirs*.

In a *gas cycling operation*, the lean gas (the resulting gas stream after it has passed through the separators and the condensate has been removed) is reinjected into the reservoir, where it maintains pressure, absorbs condensate, and is ultimately produced, processed, and reinjected. Cycling operations are illustrated in Figure 11-3.

When injection of lean gas will no longer contribute to increased liquid recovery from the reservoir, injection of gas is discontinued, and future produced gas is sold after processing. After the injection program has been discontinued, the reservoir is said to be in a *blowdown* phase.

Figure 11-3: Gas Cycling Operations



For pressure maintenance of either oil reservoirs or retrograde condensate reservoirs, the injected gas may be part or all of the field's production or may be purchased gas from other sources.

Artificial Gas Lift

Gas may be injected into an oil well (not the reservoir) between the tubing and casing. The pressure of the injected gas opens a valve in the tubing string near the bottom of the well, allowing the gas to combine with the crude oil in the tubing, thereby lifting the oil from the bottom of the well to the surface. Similar pressure-sensitive valves may be installed at selected points on the tubing string to help start the artificial gas lift.

MEASURING VOLUMES OF OIL AND GAS

One of the most important steps in revenue accounting is determining the volume and quality of the oil, condensate, and natural gas being produced and sold. The physical activities of taking readings, testing, and measuring are performed by the purchaser and company field personnel. However, it is the revenue accountant's responsibility to know and understand these procedures and to periodically ensure that correct procedures are being followed. This is a major point in internal control because revenue can be lost if inaccurate measurements are made for volume or for quality. The American Petroleum Institute has issued numerous specifications and standards related to production and measurement. The revenue accountant should be familiar with these standards and must ensure compliance by field personnel and the purchaser's representatives.

MEASURING OIL VOLUMES PRODUCED AND SOLD

As mentioned earlier, in the section on *Removing the Products from the Lease*, oil is measured by one of two methods: (1) manually by gauged tank levels, where the product may be moved by truck, barge, tank car, or pipeline to a purchaser or refinery, or (2) automatically, by a LACT unit, where the product flows into the purchaser's pipeline.

Manual Measurement—Gauging A Tank

Manual measurement of oil volume sold from a stock tank involves several steps: (1) obtaining volume measurements of an empty stock tank to determine the amount of oil that can be held at various tank levels, (2) measuring the levels of oil in the tank before the oil is removed and after the oil is removed, and (3) converting the measured oil levels to oil volumes to compute the reduction of oil volume in the tank.

Before a new tank battery is put into operation, each empty tank is *strapped*; that is, the tank dimensions are measured to determine the fluid volume for any given fluid level in the tank. The tank is normally measured at four or five key points. Strapping is usually performed by an employee of the company that sold the tank, in accordance with industry standards. The measurements are witnessed by a representative of the producer and recorded on a *tank strapping report*, which is signed by the tank company employee and the producer's representative. The strapping report is sent to an independent tank engineer who computes the volume of oil that can be contained in each interval (usually each one-quarter inch) of height of the tank. Although the tanks are manufactured to uniform dimensions, they tend to bulge outward at the middle. In a large tank, the slight bulge can account for several barrels of oil. The standard unit of measurement of crude oil is a barrel of 42 gallons of marketable crude oil at a temperature of 60 degrees Fahrenheit (60º F) and at atmospheric pressure and referred to as a *stock tank barrel,* abbreviated *STB*. The capacity of the tank in barrels, according to the height of liquid in the tank, is prepared in table form, usually referred to as a *tank table.* The tank table is used for manual calculation of oil volume. The tables are customarily prepared to show the capacity for each one-quarter inch from the bottom to the top (there are 9,702 cubic inches in a barrel). A portion of a typical tank table is shown in Figure 11-4.

The portion of the table illustrated shows the volume for each one-fourth inch from 1' to 1'10 3/4" and from 6' to 6'10 3/4". Other table readings have been omitted from Figure 11-4 to simplify its use later in the chapter.

Figure 11-4: Illustrative Tank Table

[Values for all but two columns have been omitted.]

BARRELS (42 Gallons) FEET PER ONE-QUARTER INCH STRAPPED BY J. SMITH FOR KT OIL BY FOR	DISTRICT: COVINGTON OWNER: KT OIL LEASE: KNIGHT P.L. TANK No. 41-2 OLD No. CONN.

			1	64	86	**2**			**3**			**4**			**5**			**6**	388	95	**7**			**8**		
			1/4	66	21													1/4	390	30						
			1/2	67	56													1/2	391	65						
			3/4	68	91													3/4	393	00						
			1	70	26													1	394	35						
			1/4	71	61													1/4	395	70						
			1/2	72	97													1/2	397	05						
			3/4	74	32													3/4	398	40						
			2	75	67													2	399	75						
			1/4	77	02													1/4	401	09						
			1/2	78	37													1/2	402	44						
			3/4	79	72													3/4	403	79						
			3	81	07													3	405	14						
			1/4	82	42													1/4	406	49						
			1/2	83	78													1/2	407	84						
			3/4	85	13													3/4	409	19						
			4	86	48													4	410	54						
			1/4	87	83													1/4	411	89						
			1/2	89	18													1/2	413	24						
			3/4	90	53													3/4	414	59						
			5	91	88													5	415	94						
			1/4	93	23													1/4	417	29						
			1/2	94	58													1/2	418	64						
			3/4	95	94													3/4	419	99						
			6	97	29													6	421	33						
			1/4	98	64													1/4	422	68						
			1/2	99	99													1/2	424	03						
			3/4	101	34													3/4	425	38						
			7	102	69													7	426	73						
			1/4	104	04													1/4	428	08						
			1/2	105	39													1/2	429	43						
			3/4	106	75													3/4	430	78						
			8	108	10													8	432	13						
			1/4	109	45													1/4	433	48						
			1/2	110	80													1/2	434	83						
			3/4	112	15													3/4	436	18						
			9	113	50													9	437	53						
			1/4	114	85													1/4	438	88						
			1/2	116	20													1/2	440	22						
			3/4	117	56													3/4	441	57						
			10	118	91													10	442	92						
			1/4	120	26													1/4	444	27						
			1/2	121	61													1/2	445	62						
			3/4	122	96													3/4	446	97						

The table shows that if the level of liquid is 6'10", the liquid volume is 442.92 barrels; at 1'4", the volume is 86.48 barrels. If the tank level is 6'10" and liquid is removed, lowering the level to 1'4", the volume of the removed liquid is 442.92 less 86.48 or 356.44 barrels, unadjusted for temperature or gravity.

If the purchaser of the oil uses electronic data processing equipment to compute the volume of oil, the tank table is supplemented by a table of tank increment factors representing the barrels of oil per one-quarter inch between various levels of the tank. A table of tank increment factors or *increment factor sheet* is shown in Figure 11-5.

Figure 11-5: Illustrative Table of Tank Increment Factors

13-350-S

OUR PETROLEUM COMPANY

INCREMENT FACTOR SHEET

District Newgulf

Tank Number 19127

Date of Table May 12, 2000

Operator Name **Our Petroleum Co.**

Pipe Line Company

Lease Name

Lease No. 17-583 Pipe Line Code Gauger District

Truck Code State Code Tax Code Price Code

Tank Strapped By:

No.	INCREMENT (Use 5 Decimals) Barrels per ¼ inch		VERTICAL COMPONENTS From Feet		To		Volume in Barrels Per Vertical Component	No. of QTR. INCHES From	To
	1	34600	0	0	0	8	43.07200		
	1	15791	0	8	0	10	9.26328		
	1	34891	0	10	3	0	140.28664		
	1	34605	3	0	6	0	193.83120		
	1	34106	6	0	7	9	112.64904		

Unadjusted Tank Capacity	499.10216
Correction Factor and Cone Capacity	0.00931
Total Adjusted Tank Capacity	499.11147

The tank table or its equivalent table of tank increment factors is the basic reference source for calculating the volume of oil produced into or delivered from a lease tank. Today, tank tables are stored as computer files for fast accurate conversion of tank levels into volumes produced or sold.

A gauger is a person, usually the oil purchaser's representative, who measures the quantity and quality of the lease products. The term *pumper* refers to the producing company's representative responsible for operating and maintaining the equipment on the lease. The pumper also has responsibility for the E&P company's testing, gauging, and initial recording of volumes produced and sold. The pumper will generally visit the lease site on a daily basis to gauge the tank and record the results on a *pumper's report* (sometimes called a *gauge sheet*). This provides a day-to-day operational report and acts as a check against the *run ticket* (a term used for the receipt issued by the purchaser at the point of delivery) which records the volumes sold. A pumper can be either an employee of the producer or an independent contractor hired by the producer. The pumper has the right and responsibility to witness the gauger's testing and measuring the oil. The E&P company may permit the pumper to not always witness the gauger's activity but merely reconcile the gauger's run ticket data to crude oil levels noted on the pumper's report.

Immediately before *running* a tank of oil (i.e., moving the oil) into the pipeline or truck, the oil purchaser's representative (observed by the oil producer's representative) measures the top level of the oil, or *opening gauge*, with a steel measuring tape called a *gauge tape* weighted by a brass weight called a *plumb bob* or *gauge bob*. By the use of a device known as a *thief*, which permits extraction of oil from any desired level in the tank, samples of the oil are secured for several intervals just above and below the pipeline connection in order to determine whether the BS&W content of the oil is less than one percent. This test is referred to as a *shakeout*. If the tank contains too much BS&W, the measurements will indicate how much BS&W must be drained from the tank in order to lower the salable oil to the pipeline connection. The samples obtained are placed in glass tubes and spun in a centrifuge. Centrifugal force causes BS&W to settle to the bottom of the glass tube and the BS&W content can be read from graduations on the tube. The amount of BS&W in the oil actually sold is also determined by this method.

Factors Determining Oil Price and Volume

In the United States, crude oil sells at a price per barrel, based usually on prices in a *posted price bulletin* and based on crude oil volume in terms of tank barrels.[22] Price varies based on four factors:

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[22]Posted price bulletin is further explained and illustrated in Chapter Twelve.

1. General geographic location, such as West Texas, identified on the posted price bulletin,
2. General degree of sulfur in the crude oil,
3. Date of sale, and
4. The oil density (measured in degrees of *API gravity*) at 60° F.[23]

The first two factors, location and general sulfur content, do not change for a given oil reservoir. Sulfur is a contaminant not typically removed from the oil at the lease and is expensive to remove at the refinery. So crude oil high in sulfur content sells for less than crude oil with little sulfur. For pricing crude oil, sulfur content is expressed in three degrees or classes—(1) *sweet* crude having little sulfur, generally less than 0.6 percent by weight (2) *intermediate* having a sulfur content generally between 0.6 percent and 1.7 percent and (3) *sour* crude with a sulfur content generally above 1.7 percent.[24] The general location and sulfur factors are expressed in the price bulletin as a type or name of crude oil, such as West Texas Intermediate or Louisiana Sweet.

Posted prices vary by date of sale for various reasons, such as (1) changes in the global and national prices of crude oil and refined products and (2) changes in local supply of and demand for crude oil and refined products.

The density of the crude oil affects the cost to refine the crude oil into valuable products, such as gasoline. Light crude oils with high API gravities command a higher selling price than heavy crude because

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[23]The relation between API gravity and specific gravity is purely mathematical. API gravity varies inversely with specific gravity. For example, oil with specific gravity of 0.90 has an API gravity of 25.7, while oil with a specific gravity of 0.80 has an API gravity of 45.4. See API gravity in the glossary for further explanation and for the conversion formula.

[24]Source: *Dictionary of Petroleum Exploration, Drilling & Production*, copyright 1991, PennWell Publishing Company. The *Dictionary* added that sweet crude may refer to crude with a sulfur content below one percent while sour may refer to crude with a sulfur content above one percent. *Oil Markets and Prices*, copyright 1993, Oxford University Press, notes that West Texas Intermediate (WTI) is actually a sweet crude with a sulfur content of 0.4 percent and a 40° API gravity. The NYMEX crude oil futures contract is not strictly for WTI but for a sweet crude oil with a sulfur content less than 0.5 percent and an API gravity between 34° and 45°. Several U.S. and foreign sweet crudes meet those specifications.

refining light crude yields a high proportion of gasoline without employing exotic, expensive refining techniques to break long, heavy hydrocarbon molecules into the smaller, lighter molecules found in gasoline. Oddly, heavy crude oil has more mass, but less value, per barrel.

The Run Ticket

The run ticket is a legal document on which the gauger, witnessed by the pumper, records the following information necessary to establish the correct price and STB volume of the oil removed:

1. Specific location or tank, which indicates the first two pricing factors of general geographic location and whether the crude is sweet, intermediate, or sour to establish the type or name of the crude as expressed on the posted price bulletin;
2. The date of removal or sale, which is the third pricing factor;
3. The *observed* API gravity and the corresponding *observed* temperature of the oil sample (so that observed API gravity at the observed temperature can be *corrected* to API gravity at 60° F, the fourth pricing factor and a secondary factor in determining STB volume);
4. The tank level of oil just prior to oil removal and a corresponding crude oil temperature;
5. The tank level of oil just after oil removal and a corresponding crude oil temperature; and
6. The BS&W content of the crude oil removed.

The tank levels determine gross oil volumes at the corresponding oil temperatures. Gross volumes can be *corrected* to stock tank barrels at 60° F for the calculated API gravity at 60° F. Full correction includes volume reduction to exclude BS&W content.

The gauger measures the oil's API gravity with a hydrometer. Oil temperature is taken by lowering a thermometer into the oil in the tank.

The information recorded on the run ticket also includes the purchaser's name, the lease owner or operator's name, the run ticket number, and the signatures of the gauger and pumper.

The run ticket also has spaces for recording gravity adjusted to 60º F and the result of volume calculations. These calculations are not completed on the copy of the run ticket supplied for accounting purposes but are made by employees of the production department for use in control of operations and in compliance with requirements of regulatory bodies. The calculations, especially in the case of most large companies, are made with the aid of electronic data processing equipment. Whether performed manually or electronically, the calculations involve essentially the same process. Figure 11-6 illustrates a run ticket reflecting a delivery of oil from the tank whose tank table was illustrated in Figure 11-4.

The run ticket generated by a LACT unit is called a *meter ticket*. The meter ticket will contain the meter readings for volumes, observed gravity and temperature, average line temperature (if the meter is not temperature compensated), and the BS&W.

Determining API Gravity at 60º F

The API gravity at observed temperature is corrected to *API gravity at 60*º F (also called *true gravity* or *corrected gravity*) by the use of a gravity correction table. The gravity correction table, a part of which is illustrated in Figure 11-7, typically shows true gravity for each one-tenth degree of observed gravity. For example, using Figure 11-7, if the observed gravity is 23.2º API and the observed temperature is 100º F, then the true or corrected gravity is 20.9º API at 60º F.

Determining the Volume Correction Factor

The observed volume at an observed temperature is multiplied by a volume correction factor to calculate volume at 60º F. The volume correction factor is a function of the observed temperature and the oil's API gravity at 60º F. The volume correction factor can be determined from a *volume correction table*. Figure 11-8 illustrates a volume correction table for various temperatures from 50º F to 104º F and API gravities of 20º to 29º.

Figure 11-6: Pipeline Run Ticket

CRUDE PURCHASING, INC.
CRUDE OR PRODUCTS TICKET
Lease Run, Delivery or Receipt

OPERATOR (OR FIELD LOCATION)	***Our Oil Company***
LEASE OR COMPANY NAME ***24001***	Delivery [ ] Receipt [X]
FOR ACCOUNT OF	Crude Grade or Product
CONSIGNEE (if delivered to connecting carrier)	Reid Vapor Pressure
CREDIT	
MOVED BY: Pump [ ] Gravity [ ] Truck [X]	TO (line or station) ***XYZ Pipeline Co.***
TANK SIZE ***500***	POWER FURNISHED BY OR TRUCKED BY

MO.	DAY	YR.	DISTRICT NO.	TICKET NO.
7	***15***	***2000***		***1442***

TANK OR METER NO.	OFFICE CODES	LEASE NO.
2401		

	OIL LEVEL					CALCULATIONS OR REMARKS
GUAGE	FT.	IN.	FRACT.	TEMP		
1st	***6***	***0***	***1/2***	***102***		
2nd	***1***	***9***	***1/2***	***86***		

OBS. GTY. & TEMP.		TRUE GRAVITY
23.2	***100 F***	
CODES: POWER	TRUCK	BS & W ***0.4%***

METER

TRANSACTION NO.	PRINTING HEAD NO.	[ ] Barrels	[ ] Gallons	10ths
OFF				
ON				

AVG. METER PRESS	METER FACTOR	METERED BARRELS	
psi			

TEMPERATURE COMPENSATED?	AVG. LINE TEMP	COMPRESSIBILITY FACTOR	NET BARRELS
[ ] Yes [ ] No	° F		

ON	GAUGER ***Ernest Hobbs***	TIME ***8:00 AM***	
	OPERATOR'S WITNESS OR WAIVER NO. ***Terry Roundtree***	SEAL OFF ***83661***	
OFF	GAUGER ***Ernest Hobbs***	TIME ***9:10 AM***	DATE ***07/15/2000***
	OPERATOR'S WITNESS OR WAIVER NO. ***Terry Roundtree***	SEAL ON ***84471***	

INSERT FACE DOWN ⇩ THIS END FIRST

Figure 11-7: Gravity Correction Table

API Gravity @ 60⁰ F	*For API Observed Gravity of 23.0-23.8⁰*									
		23.0	23.1	23.2	23.3	23.4	23.5	23.6	23.7	23.8
For observed temperature of 100 to 114 ⁰F	100	20.7	20.8	20.9	21.0	21.1	21.2	21.2	21.3	21.4
	101	20.6	20.7	20.8	20.9	21.0	21.1	21.2	21.3	21.4
	102	20.5	20.6	20.7	20.8	20.9	21.0	21.1	21.2	21.3
	103	20.5	20.6	20.7	20.8	20.9	21.0	21.1	21.2	21.3
	104	20.4	20.5	20.6	20.7	20.8	20.9	21.0	21.1	21.2
	105	20.4	20.5	20.6	20.7	20.8	20.9	20.9	21.0	21.1
	106	20.3	20.4	20.5	20.6	20.7	20.8	20.9	21.0	21.1
	107	20.3	20.4	20.5	20.6	20.7	20.8	20.8	20.9	21.0
	108	20.2	20.3	20.4	20.5	20.6	20.7	20.8	20.9	21.0
	109	20.2	20.3	20.4	20.5	20.6	20.7	20.7	20.8	20.9
	110	20.1	20.2	20.3	20.4	20.5	20.6	20.7	20.8	20.9
	111	20.0	20.1	20.2	20.3	20.4	20.5	20.6	20.7	20.8
	112	20.0	20.1	20.2	20.3	20.4	20.5	20.5	20.6	20.7
	113	19.9	20.0	20.1	20.2	20.3	20.4	20.5	20.6	20.7
	114	19.9	20.0	20.1	20.2	20.3	20.4	20.4	20.5	20.6

Figure 11-8: Volume Correction Table

ASTM-IP

20-29° API
50-100° F

Observed Temper-ature, ° F	API Gravity at 60° F.									
	20	21	22	23	24	25	26	27	28	29
	Factor for Correcting to Volume at 60° F.									
50	1.0039	1.0040	1.0040	1.0040	1.0040	1.0041	1.0041	1.0041	1.0042	1.0042
51	1.0035	1.0036	1.0036	1.0036	1.0036	1.0037	1.0037	1.0037	1.0038	1.0038
52	1.0031	1.0032	1.0032	1.0032	1.0032	1.0033	1.0033	1.0033	1.0033	1.0034
53	1.0028	1.0028	1.0028	1.0028	1.0028	1.0029	1.0029	1.0029	1.0029	1.0029
54	1.0024	1.0024	1.0024	1.0024	1.0024	1.0024	1.0025	1.0025	1.0025	1.0025
85	0.9902	0.9902	0.9901	0.9900	0.9899	0.9899	0.9898	0.9897	0.9896	0.9895
86	0.9898	0.9898	0.9897	0.9896	0.9895	0.9895	0.9894	0.9893	0.9892	0.9891
87	0.9895	0.9894	0.9893	0.9892	0.9891	0.9891	0.9890	0.9889	0.9888	0.9887
88	0.9891	0.9890	0.9889	0.9888	0.9887	0.9887	0.9886	0.9885	0.9884	0.9883
89	0.9887	0.9886	0.9885	0.9884	0.9883	0.9883	0.9882	0.9881	0.9879	0.9878
100	0.9844	0.9843	0.9842	0.9841	0.9839	0.9838	0.9837	0.9835	0.9834	0.9832
101	0.9840	0.9839	0.9838	0.9837	0.9835	0.9834	0.9833	0.9831	0.9830	0.9828
102	0.9836	0.9835	0.9834	0.9833	0.9831	0.9830	0.9829	0.9827	0.9826	0.9824
103	0.9833	0.9831	0.9830	0.9829	0.9827	0.9826	0.9825	0.9823	0.9822	0.9820
104	0.9829	0.9827	0.9826	0.9825	0.9823	0.9822	0.9821	0.9819	0.9817	0.9816

Computing the Volume Run

The steps for computing the standard barrels at 60º F of oil run from a tank are summarized in Figure 11-9.

Figure 11-9: Computing The Volume Run

	Example Amount	Example Source
Per Run Ticket from the Field:		
Observed gravity of sample	23.2	Fig. 11-6, Run Ticket
Observed temperature of sample	100ºF	Fig. 11-6
1st gauge height	6' 0.5"	Fig. 11-6
1st gauge temperature	102ºF	Fig. 11-6
2nd gauge height	1' 9.5"	Fig. 11-6
2nd gauge temperature	86ºF	Fig. 11-6
BS&W content	0.4%	Fig. 11-6
Production Department's Calculations:		
Step 1: Correct to "true gravity" at 60ºF	20.9	Fig. 11-7, Gravity Correction Table
Step 2: Determine "opening" fluid volume	391.65	Fig. 11-4, Tank Table
Step 3: Correct to bbls at 60ºF	385.19	Fig. 11-8, Volume Correction Table
Step 4: Determine fluid volume left in tank	116.20	Fig. 11-8
Step 5: Correct to bbls at 60ºF	115.01	Fig. 11-8
Step 6: Determine net fluid bbls removed	270.18	[385.19 - 115.01]
Step 7: Adjust bbls to exclude BS&W	269.10	[270.18 x 99.6%]
	i.e., 269.10 bbls of 20.9 API gravity crude sold	

Related monthly processes:
a) Accumulate adjusted volumes by tank.
b) Compare accumulated total to purchaser's run statement.
c) Allocate sales volumes to wells.
d) Prepare production and sales reports for government agencies and internal records.

Step No. 1. Correct the observed gravity at the observed temperature to the *true gravity* at 60º F.

The observed gravity indicated on the Figure 11-6 run ticket is 23.2º API at 100º F. By referring to the gravity temperature correction table in Figure 11-7, the true gravity is determined to be 20.9º API.

Step No. 2. Determine the gross amount of fluid (oil and BS&W) in the tank before the run by applying the first measurement to the proper tank table (Figure 11-4). The first measurement of oil level indicated on the run ticket is 6' 1/2" at 102º F. By referring to the tank table (Figure 11-4), the gross volume of 391.65 barrels is obtained.

Step No. 3. Correct the volume obtained in Step No. 2 to the volume at 60º F. This is accomplished by using the volume correction table (Figure 11-8) to determine the factor to be applied to the observed volume.

Our Oil Company rounds off the true gravity reading of 20.9º API to the nearest whole number to arrive at an adjusted true gravity of 21º API.[25] The *volume correction* table shown in Figure 11-8 shows that for gravity of 21º API and an observed temperature of 102º F (the temperature for the first measurement of oil level from the run ticket), the volume correction factor to adjust the volume to 60º F is 0.9835. Multiplying this factor of 0.9835 by the volume of 391.65 barrels on the first observed reading yields a corrected volume of 385.19 barrels.

Step No. 4. Determine the gross amount of fluid remaining in the tank after the run by applying the second measurement to the proper tank table. The second measurement indicated on the specimen run ticket is 1' 9-1/2" at a temperature of 86º F. By referring to the specimen tank table (Figure 11-4), the gross volume of 116.20 barrels is obtained.

Step No. 5. Correct the volume obtained in Step No. 4 to the volume at 60º F as in Step No. 3. The true gravity is 20.9º API, rounded to 21º. The volume correction table (Figure 11-8) shows that for API gravity of 21º at temperature of 86º F, the reduction factor is 0.9898. Applying this factor to the volume of 116.20 barrels at the second measurement yields a corrected volume of 115.01 barrels.

Step No. 6. Determine the net volume of fluid (oil and BS&W) run by subtracting the result obtained in Step No. 5 from that obtained in Step No. 3: 385.19 – 115.01 = 270.18 barrels.

Step No. 7. Adjust the volume of liquid run for the BS&W content. Since BS&W content indicated on the run ticket is 0.4 percent, the oil content of the volume run is 99.6 percent. Thus the corrected net volume of oil sold is 270.18 barrels x .996 = 269.10 stock tank barrels at 20.9° API gravity at 60° F. For revenue determination, oil volume is measured to the hundredth barrel.

For volume measurement, the crude volume at the observed temperature is sometimes called the *gross volume* while the volume of stock tank barrels (at the standard temperature) is the *net volume*. In accounting for an owner's share of 8/8ths production, the term *gross volume* and *net volume* are used to refer to 8/8ths production and an owner's net share of the 8/8ths production, respectively.

When crude oil is used for fuel, or other operating or development purposes (either on the lease where produced or on another lease), the

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[25] Such rounding has little effect on revenues. Even a full 1º difference in API gravity would change the volume by only 0.01 percent or about 58 cents for the 385.19 barrels if valued at $15 per barrel.

amount withdrawn from the tanks is recorded on a company run ticket with essentially the same information as shown on a pipeline run ticket so that proper accounting for lease revenue, expense, and taxes may be made. If the crude oil is assumed to be subsequently recovered, as when it is used in connection with the completion of a new well, appropriate affidavits to that effect are supplied by production department personnel so that taxes are not paid twice.

Automatic Measurement—The LACT Unit

A significant development in automation of oil field functions has been the LACT unit. This automatic unit meters oil, records temperature, takes and stores oil samples at predetermined intervals for later gravity determination, measures the BS&W content, diverts the oil back through the treating system if the BS&W is too high, turns the oil into the pipeline, and cuts off the valves when the oil has been run into the pipeline. If the unit malfunctions, it will shut down and an alarm will sound in the field office so that personnel will investigate and correct the malfunction.

When a LACT unit is used to record the sale of oil into a pipeline, a meter is used to measure the volume of oil that enters from the LACT unit's *dump tank* (also called the metering tank or surge tank). The dump tank is not strapped; therefore, there are no tank tables or increment factor sheets. Instead, the LACT meter needs to be *proved* on a regular basis to determine its accuracy. The meter proving report supplies a meter accuracy factor. The meter factor is then applied to the difference between the opening meter reading and closing meter reading to obtain the true gross barrels that entered the pipeline.

All the measurements taken and data accumulated are recorded on a meter ticket for the production and accounting records; depending on the software used, the gravity and temperature adjustments may be calculated automatically by the unit, eliminating production staff time.

DETERMINING VOLUMES OF NATURAL GAS SOLD

Natural gas is increasing in importance in the U.S. Wellhead revenue for natural gas exceeded crude oil revenue for the first time in 1993.[26] In order to determine the quantity of gas that has changed ownership when a

[26] DeGolyer and MacNaughton *Twentieth Century Petroleum Statistics*, 1994.

sale is made, the unit of measurement must be specified and the volume calculated in the manner agreed upon in the gas sales contract.

Measuring Nonprocessed Gas Volumes Produced and Sold

As pointed out in Chapter One, natural gas is measured in two ways—by volume and by heat content. The standard volume unit of measure in the U.S. is a *mcf***,** which is the amount of gas in a thousand cubic feet at standard atmospheric pressure and temperature. The standard pressure bases used by the industry for gas volume reporting are approximately sea-level atmospheric pressures of 14.65, 14.73, and 15.025 pounds per square inch absolute (psia). When arriving at contract settlements or filing state and federal production reports, the accountant must determine which pressure base is required by which entity. Most federal governmental reporting is done at the 14.73 psia pressure base. Some state reporting requires the pressure base to be 14.65 psia (Texas, Oklahoma) or 15.025 psia (Louisiana). The standard temperature used is 60° F.

The heat content measurement called a *British thermal unit* (Btu) is defined as the heat necessary to raise the temperature of one pound of water by 1° F.

Historically, many gas sales contracts were priced on a *mcf* basis. Now, most contracts express prices in terms of one million British thermal units or mmBtus. The prices are independent of gas temperature or pressure. Some contracts, particularly with utility companies, are expressed in *decatherms*. A decatherm equals one mmBtu. The Btu content (energy) in a volume of gas does not change with a pressure base change. Thus, the total Btu determined at one pressure base is equal to the total Btu determined or reported at another pressure base. From a production standpoint, most companies record gas produced in mcf—this makes it easier when analyzing reserves. Most state and federal regulatory agencies require reports in mcf. The U.S. is the only market not using the metric system for volume measurements.

When gas quantities are expressed in volume and price is initially expressed in terms of heat content or mmBtu, it becomes necessary to convert the price per mmBtu to a price per mcf. To do so, the price per mmBtu is multiplied by the heating value (Btu) of a unit of gas volume (mcf). For example, if the price is $2.00 per mmBtu and the Btu content is 1.1000 mmBtu/mcf at 14.73 psia, then the price per mcf at 14.73 psia is $2.20. For the sake of comparability, the Btu content of the gas and the mcf must both be measured using the same pressure base. In turn, gas volumes can be converted to mmBtu by multiplying the volumes expressed in mcf by the Btu content per mcf to arrive at the number of mmBtus purchased, adjusting for any differences in pressure base. For example, if one bcf measured at 14.65 psia were sold, then the volumes sold at the higher pressure of 14.73 psia would be smaller, specifically, one bcf x 14.65 /14.73, i.e., 0.9946 bcf. If the Btu content per mcf at 14.73 psia were 1.1 mmBtu, then the mmBtu sold would be 994,600 mcf x 1.1 mmBtu/mcf, i.e., 1,094,060 mmBtu.

Gas volume measurement is accomplished when gas flows through a *meter* that records temperature, pressure, or other specific information needed to calculate the volume. The petroleum industry uses four types of meters: (1) the orifice meter, (2) the turbine meter, (3) the diaphragm positive displacement meter (the type used to measure most residential use), and (4) the rotary gas displacement meter. However, metering technology is looking to the future for sophisticated electronic or ultrasonic metering systems, especially in offshore development where gas quantities are larger and the accessibility of the meter is more difficult. Until these systems are perfected and affordable, most companies continue to use one of the four metering systems in combination with various electronic communication systems combined with internal or outsourced procedures. The subsection below will briefly explain the use of the common orifice meter and will illustrate the peculiarities and difficulties in measuring natural gas. The calculations are very involved and dependent on accurate readings from the meters and accuracy in applying those readings in a series of formulas.

As discussed earlier, gas flows through pipelines from the individual well or wells to a central facility, where some separation and processing may take place to ensure that sufficient residues are removed so that the gas can move through the pipeline on to a purchaser, a transporter, or a gas processing plant. To facilitate proper accounting, volume readings will be taken at the wellhead, the central delivery facility, and at points where gas leaves or re-enters the pipeline or gathering system to (1) run lease equipment, (2) be flared into the air, (3) be processed for NGL removal, (4) be returned from the processing plant, or (5) be injected into a reservoir. The producer may have a check meter installed on the line downstream of the purchaser's or transporter's sales meter for purposes of verifying and proving the accuracy of the sales meter. If there is no check meter, E&P company representatives may regularly witness the sales meter calibration by specialists engaged by the purchaser or transporting pipeline.

Because of the complex nature of gas, these readings will rarely agree, and the gas sales contract will specify an allowable percentage difference. If gas measurement audits find that the difference is larger than the allowable amount specified in the contract, then adjustments must be made to correct the volumes.

Measuring Natural Gas with an Orifice Meter

In general, measurement of natural gas volume is based on the relationship of the space occupied by a given weight of gas to conditions of temperature and pressure. An orifice meter consists of small pipe, perhaps two or three inches in diameter, divided by a doughnut-shaped flat plate barrier with a hole in the middle. The hole might be 0.75 inches in diameter. The meter is mounted to and alongside the gas pipeline, allowing gas to flow through the meter and then back into the pipeline. As natural gas flows through the two-inch pipe and squeezes through the 0.75-inch orifice in the plate, the gas pressure drops just downstream of the orifice. The pressure drop is called *differential pressure*. The gas pressure before the orifice is called *static pressure*.

The greater the volume of gas moving through the pipe in a given time period, the greater the differential pressure and/or the greater the static pressure. So the orifice meter constantly measures both differential pressure and static pressure to enable volume to be calculated for a given time period, such as a day. The constant measurements are recorded by the meter on a circular paper chart (that generally revolves in a day or a week) marked by two pens (one for differential pressure and one for static pressure) that move to and from the outside of the paper circle as it slowly turns. Once the paper chart has fully revolved and been marked by the pens, the chart is replaced and *integrated*, i.e., read to determine the recorded pressures as further discussed below.

The recorded pressures are entered into equations that calculate the gas volume flowing through the meter for the given time period. An overly simplistic equation would be:

mcf/day = the square root of (differential pressure times static pressure) times a special factor

where the special factor is a function of such data as the meter's pipe diameter, orifice size, gas specific gravity, and gas temperature.

The formulas for calculating gas volumes from orifice meter readings have been established by various research organizations and published in numerous technical reports. The basic formulas should result in reasonably accurate metered volumes of an *ideal* gas. However, natural gas is not an ideal gas since it is composed of an infinite number of combinations of true gases and light hydrocarbon vapors. Therefore, in order to determine correct volume, formula adjustments are made for base pressure, flowing temperature, specific gravity, and supercom-pressibility. The extent of these adjustments may be influenced by company policy, contractual stipulations, regulations and tariffs.

Prior to chart integration, the company's production department typically receives the orifice meter charts from the field. At the department, the charts are logged in a chart register by data sequence to ensure that all charts from a particular location have been received. An employee, trained in the field to recognize such erratic registrations as freeze-ups, over-ranging, or possible malfunctioning of metering devices, reviews the charts. The source of the gas and basic metering conditions are noted on the chart by field personnel and verified by comparison with records compiled from the various field measurement and attest reports.

If all of the information is correct, the charts are processed by an integrator machine that uses the temperature of the gas flow and the pressure readings on the orifice plate to quickly and accurately compute data to determine the gas volume. Integrators are calibrated daily to a very close tolerance, and the operator keeps a record of the calibration to attest the accuracy of the chart readings.

Pertinent flow data and the computed gas volumes for each chart are posted to the gas statement so that a cumulative volume may be reported for each meter station each month.

Generally, internal integration is no longer used; many producers outsource these calculations to companies skilled in integration. Manual paper charts or electronic readings from the lease site are shipped directly to the outside company. The outside company delivers the volumes and other readings to the production accounting department of the producer. The production accounting department generates the internal statements, such as the run tickets, sales tickets, inventory statements, production statements, and governmental volumetric reporting. These statements are in turn used by the producer's revenue accounting department for verifying and recording sales, determining take-in-kind allocations, and governmental sales reporting.

Measuring NGL Volumes Produced and Sold

NGLs are the liquids recovered from a *wet* (or *rich*) natural gas stream. The constituents of the gas are determined by tests or analyses of the gas streams delivered from each lease or combination of leases serving a gas processing plant. The *chromatograph* and the *spectrometer* are two devices used for such analysis.

NGL volumes are measured with turbine meters or similar meters used to measure natural gas. A turbine meter uses the flowing NGL to spin a turbine. The meter measures the turbine's rotation speed, which indicates flow rate for a given type of fluid flowing through the meter. Alternatively, the meter may be a *mass measurement meter*, which weighs the volume of gas to indicate the NGL portion of the measured gas volume. NGL portions are expressed in terms of g*pm* or *gal/mcf* (gallons per thousand cubic feet). For example, gas having a 1.0 gpm contains one gallon of NGL in each mcf. NGL volume is expressed in gallons.

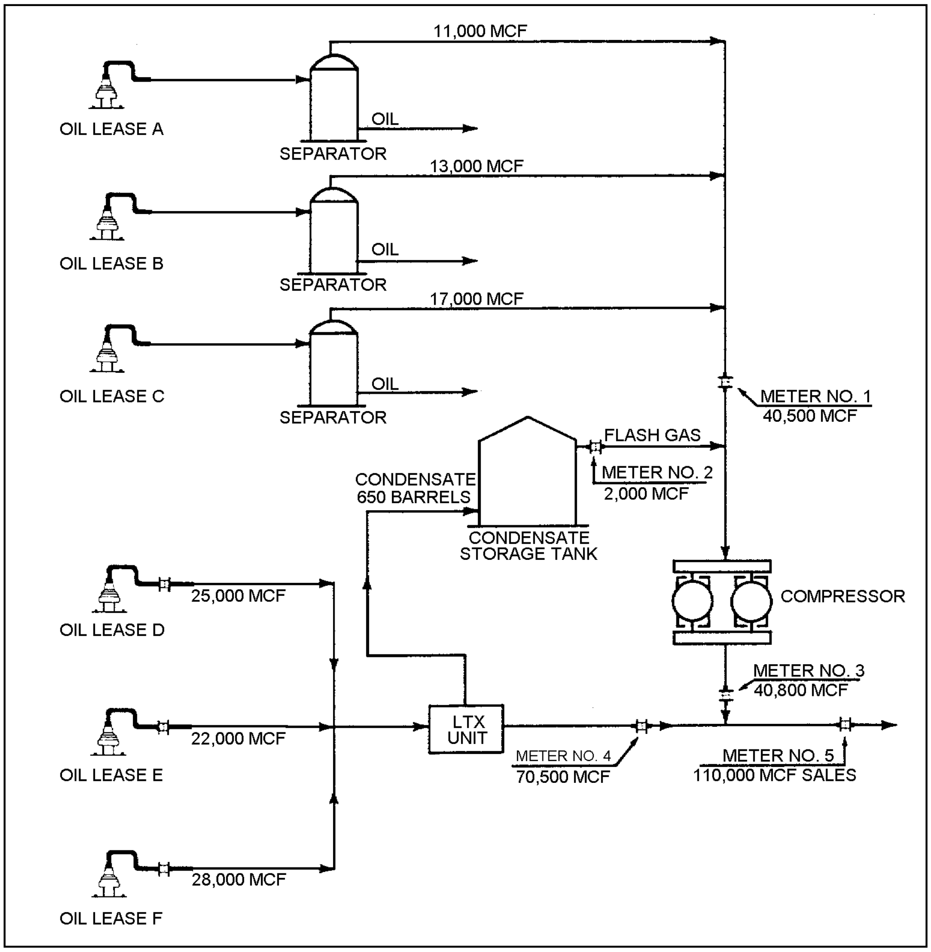
Allocating Gas Sales

The allocation of sales from multiple leases served by a central delivery facility is a rather complex procedure requiring several calculations. The following example, used with permission, from Section 6 of COPAS Bulletin No. 7,[27] demonstrates the allocation process. Figure 11-10 is a gas flow schematic (also called a *gas flow chart*) for the example.

Leases A, B, and C in Figure 11-10 all have wells classified as oil wells that also produce gas. The gas emerges from the oil production at lease separators. During the month, gas production was 11,000 mcf, 13,000 mcf, and 17,000 mcf from the three oil leases, respectively.

[27]Council of Petroleum Accountants Societies, Bulletin No. 7, *Gas Accounting Manual* (revised Sept. 1987). For the illustration and Figure 11-10 herein, the meter numbers are revised from the presentation in Bulletin No. 7.

Figure 11-10: Gas Flow Schematic for the Sales Allocation Example



Leases D, E, and F have gas wells. Production measured at the wellhead was 25,000 mcf, 22,000 mcf, and 28,000 mcf, respectively. Based on tests of gas from each well, the theoretical dry gas should be 96.0 percent, 93.2 percent, and 91.1 percent of the production volume from the three leases, respectively. Thus, the total theoretical volume of dry gas is 70,000 mcf (24,000 + 20,500 + 25,500 mcf) from Leases D, E, and F. The gas well gas is passed through a central LTX (low- temperature extraction) unit where condensate liquids are removed. The LTX output was 650 barrels of condensate and 70,500 mcf of lean, high-pressure gas. The condensate was piped to storage tanks where 2,000 mcf of vapors (flash gas) from the storage tank went to low-pressure gathering lines to be commingled with the oil-well gas.

The low-pressure oil-well gas (measured at Meter No. 1 to be 40,500 mcf) and the flash gas (measured at Meter No. 2 to be 2,000 mcf) pass through a compressor where they are boosted into the high-pressure sales line. A portion of the gas is burned as fuel for the compressor. Total output from the compressor (measured at Meter No. 3 to be 40,800 mcf) and the output of high-pressure gas-well gas from the LTX unit (measured at Meter No. 4 to be 70,500 mcf) were combined and sold. Meter No. 5 on the high-pressure gas line indicated that 110,000 mcf were sold. Volumes sold are allocated back to leases in five steps.

Step 1. Allocate Meter No. 5's total sales volume of 110,000 mcf to Meters No. 4 and No. 3 in proportion to 111,300 mcf combined measured throughput for Meter No. 4 and No. 3.

Meter	Metered Throughput				Allocated Sales
No. 4	70,500 mcf	x	110,000/111,300	=	69,677 mcf
No. 3	40,800 mcf	x	110,000/111,300	=	40,323 mcf
Total	111,300 mcf				110,000 mcf

Step 2. Allocate the 69,677 mcf of sales attributed to Meter No. 4 to the three gas leases on the basis of theoretical lean gas remaining after extraction of condensate.

Lease	Aforementioned Theoretical				Allocated Sales
D	24,000 mcf	x	69,677/70,000	=	23,889 mcf
E	20,500 mcf	x	69,677/70,000	=	20,405 mcf
F	25,500 mcf	x	69,677/70,000	=	25,383 mcf
Total	70,000 mcf				69,677 mcf

Step 3. Allocate the 40,323 mcf of sales attributed to Meter No. 3 to Meters No. 1 and No. 2 on the basis of metered throughput. This charges fuel gas used by the compressor to oil-well gas and flash gas.

Meter	Metered Throughput				Allocated Sales
No. 1	40,500 mcf	x	40,323/42,500	=	38,425 mcf
No. 2	2,000 mcf	x	40,323/42,500	=	1,898 mcf
Total	42,500 mcf				40,323 mcf

Step 4. Allocate the 38,425 mcf attributed to Meter No. 1 to the oil leases on the basis of oil-well gas production.

Oil Lease	Gas Production				Allocated Sales
A	11,000 mcf	x	38,425/41,000	=	10,309 mcf
B	13,000 mcf	x	38,425/41,000	=	12,184 mcf
C	17,000 mcf	x	38,425/41,000	=	15,932 mcf
Total	41,000 mcf				38,425 mcf

Step 5. Allocate the adjusted 1,898 mcf of flash gas attributed to Meter No. 2 to gas leases on the basis of condensate produced. Condensate produced by well is determined by use of well tests of condensate-gas ratios.[28]

Gas Lease	Condensate			Flash Gas
D	210 bbls	x 1,898 mcf/650 bbl	=	613 mcf
E	190 bbls	x 1,898 mcf/650 bbl	=	555 mcf
F	250 bbls	x 1,898 mcf/650 bbl	=	730 mcf
Total	650 bbls			1,898 mcf

Summary of Gas Sales Allocations

Lease	Production (mcf)	Sales (mcf) Oil Well Gas	Gas Well Gas	Flash Gas	Total
A	11,000	10,309	0	0	10,309
B	13,000	12,184	0	0	12,184
C	17,000	15,932	0	0	15,932
D	25,000	0	23,889	613	24,502
E	22,000	0	20,405	555	20,960
F	28,000	0	25,383	730	26,113
Total	116,000	38,425	69,677	1,898	110,000

GAS PROCESSING

Often natural gas contains too much natural gas liquids (ethane, propane, butane, and natural gasolines) and impurities (such as sulphur, water, and carbon dioxide) that must be removed before the gas can be

[28]Using the condensate volumes given in the COPAS Bulletin No. 7 example.

entered into downstream pipeline systems for delivery to end users. Field equipment, such as separators and dehydrators, are frequently used at the lease facilities to remove the heaviest liquids and some impurities. However, gas removed from the lease with significant NGL content (called *wet gas*) or significant impurities is sent by pipeline to a *gas processing plant* (or simply *gas plant*) to remove the NGL and impurities and provide merchantable *dry gas* (commonly called *residue gas*, which is sold at the tailgate of a gas plant) consisting predominantly of methane. Although gas processing is expensive and reduces the energy content and value of the processed gas, the recovered NGL have many uses and typically sell in the United States at prices high enough to make gas processing profitable. So Gas processing serves two functions: (1) providing merchantable dry gas for end users and (2) providing valuable natural gas liquids for the petrochemical industry and other markets. Extracted impurities such as sulphur may also be sold as a by-product of gas processing.

The processing plants are larger, more sophisticated, and far more expensive than the separation facilities at the lease. In 1998 U.S. gas processing plants extracted almost two million barrels per day of NGL, compared with 6.2 million barrels per day of U.S. crude oil production (Figure 1-7).

The accountant should have a general understanding of the purpose and functions of the various processing plants and the different types of processing contracts and arrangements.

GAS PROCESSING CONTRACTUAL ARRANGEMENTS

A gas producer often does not own the plant that processes the produced gas. In such cases, the gas producer must contract with the plant owner or plant operator. The plant owner may be a joint venture of several companies, and one or more of the plant owners typically have working interests in nearby gas fields.

If the producer does nothing contractually to reserve its processing rights prior to title passing, it loses those rights. In this case, downstream gas processing does not cost the producer anything, but the producer also derives no direct benefit from the processing and sale of products that may be done by others.

Two basic types of contracts cover the processing of gas: gas purchase agreements and gas processing agreements.

Under gas purchase contracts, title to the gas passes from the producer to the plant owner normally at a sales meter on the lease rather than at the *plant inlet*, i.e., where the gas enters the gas plant. Payments for the gas may be based on formulas involving the liquid content of the gas, stated in terms of gallons per thousand cubic feet (gpm), and sales prices received for the natural gas liquid products and the residue gas by the plant owner.

Under gas processing contracts, title to the gas does not pass to the plant owner; instead, the plant owner agrees to process the producer's gas for a fee or agrees to take a percentage of the gas or liquids in kind. The fee may be stated as (1) a percentage of the products extracted, (2) a portion of the revenue received from the sale of the products, or (3) a rate per mcf processed, per mmBtu, or per gallon extracted.

Processing agreements fall into two general categories. First, the producer may arrange for the processing of the gas, retain title to the gas, and take the liquids and residue gas back from the plant for injection, lease use, or sale under other marketing agreements, while paying a fee to the processor. Under the second type of processing agreement, the producer sells the gas before the gas is processed but retains the right to extract the liquids after the gas has entered the custody of the purchaser. The producer then contracts with the plant owner to take the gas from the pipeline, extract the liquids, and return the residue gas to the pipeline for delivery to the gas purchaser. Assuming that the gas purchaser does allow a third-party to process the gas, there are then several forms of agreements used in which the producer may derive an economic benefit from letting the processor process its gas. In such cases, the processor, in effect, purchases the gas liquids in the gas from the producer. In return, the producer bears any financial obligation to the gas purchaser for *plant volume reduction* (PVR) or *plant thermal reduction* (PTR) volumes (i.e., the residue gas having less volume and less energy than the wet gas) and forfeits the right to take its liquids in kind. The compensation to the producer can take the form of (1) a percentage of net profit from the sale of the liquids that is often on a sliding scale or (2) a straight cents per gallon of NGL sold.

There are also *keep-whole* agreements in which the parties agree that the total payment for residue gas and liquids from the processor shall be equal to or greater than the compensation that would have been received by the producer under its gas sales arrangements.

Another alternative provides that a producer may lease plant capacity for a fixed dollar amount each month. Some producers may find that the most economical decision is to buy moveable (or *skid-mounted*) processing equipment and perform their own processing and, perhaps the processing for other E&P companies' gas produced nearby.

TYPES OF PROCESSING

Processing plants consist of some combination of separation, purification, compression, extraction, liquids handling, and measurement equipment ranging from very small capacities to over one bcf per day. The processing technologies developed since the mid-1970s lend themselves to modular plant units that fit onto trucks for ready mobility. This ability to move to new sources when gas production or processing economics becomes exhausted extends plant lines.

There are generally two technologies employed in the processing of natural gas—*lean oil absorption* and *cryogenics*. Both produce liquids and can be applied to most gas streams. However, there are important differences in their capital and operating costs.

Lean oil absorption is the older technology utilizing chemical processes to extract NGLs from the gas stream as it passes through a series of special oil-bearing *contactor* towers. Lean oil plants are usually block mounted, i.e., not easily moved. They are not very efficient in the extraction of *lighter ends* of NGL components, i.e., ethane and propane. The advantages of lean oil absorption is its minimal use of fuel for compression and its high degree of flexibility in the volume of gas it can efficiently handle.

Cryogenic plants have become the preferred plant technology over the last two decades. A cryogenic process causes condensation of NGLs from the gas stream by chilling through either one or a combination of two basic methods or *cycles*—refrigeration and expansion. A *refrigeration cycle* uses various working fluids to chill the wet gas stream. An *expansion cycle* uses a large drop in pressure through valves and/or turbines to achieve very cold temperatures, sometimes with a refrigeration cycle to chill the feed gas. Cryogenic processes require large amounts of gas and refrigerant compression making fuel expense significant to the operation. Cryogenic plants are very efficient at extracting the available liquids often achieving 95 percent extraction of ethane and virtually 100 percent of the heavier components: propane, butane and natural gasoline. One draw back to cryogenic plants is that efficiency falls rapidly at levels of throughput below 50 percent of the plant's rated capacity. However, cryogenic plants can often be moved to a new location. In nearly all instances, cryogenic plants are modular in design; the primary pieces of equipment will fit onto a semitrailer for transportation.

TYPES OF PLANTS

Gas processing plants go by various names depending on the type of processing, the extent of processing, the use of the residue gas, the plant's location relative to transmission pipelines, and local or company traditions. Gas processing plants in general may be called *gas plants* or *gas-liquids extraction plants*.

There are *lean oil plants* and *cryogenic* (or *refrigeration*) *plants* to signify the type of process to remove the NGL. *Refrigeration plant* sometimes refers to a plant that cools the gas to a range of +15°F to -40°F and at the lower temperature recovers about 70 percent of the ethane, 90 percent of the propane, and virtually all of the heavier NGL. A true *cryogenic refrigeration plant* cools the gas to a range of -150°F to -225°F to recover the 95 percent ethane mentioned in the preceding subsection.

Bob-tail plant is an old term referring to a gas plant that removes the NGL as a single stream that must be sent to a *fractionation plant* (discussed below) to separate the NGL into its components. *Cycling plant* refers to a facility for which the residue gas is reinjected back into the reservoir. The term *straddle plant* generally refers to a plant located on a transmission pipeline system as opposed to a plant located between the field gas gathering system and the pipeline. *Gasoline plant* is a confusing, perhaps archaic, term for a gas plant and gets its name from the natural gasolines typically removed from the natural gas.

FRACTIONATION

A *fractionation plant* receives the NGL stream from one or more gas processing plants and fractionates the stream into separate products. A single fractionation plant may handle the output of several true gas processing plants, reducing the need for fractionation facilities at each of the gas processing plants. This approach also provides a more economical means of transporting NGL from the gas plant to a point from which the separate products can be shipped because only one pipeline is needed for moving the mixed liquids, rather than separate pipelines or shipping facilities for each of the separate products.

Fractionation is accomplished by processes of heating and cooling the NGL mix in tall towers where the components can be drawn off at the height at which they settle. Fractionation facilities operate continuously and typically have consumers and/or storage for the finished products in close proximity. It is at these facilities that NGL market prices are established and to which the expenses of transport and fractionation are then applied to arrive at plant tailgate prices for NGL.

NATURAL GAS LIQUIDS

Dry natural gas is over 90 percent methane, the simplest and smallest hydrocarbon molecule consisting of one carbon atom bonded with four hydrogen molecules (CH_4). Natural gas liquids are the slightly larger natural hydrocarbon molecules of *ethane* (C_2H_6), *propane* (C_3H_8), *butane* (C_4H_{10}), an*d natural gasoline*s (having five to ten carbon atoms per molecule, the C5s to C10s for short). NGL includes *liquefied natural gas* (LNG), a popular term for propane or a propane-butane mixture that has been compressed into a liquid for use in backyard gas barbecue grills, rural home heating and cooking, and various agricultural, industrial, and commercial applications.

Like gas and oil from the lease, NGL produced from a plant must meet certain minimum quality requirements to be considered acceptable to the carrier or purchaser. The plant operator is able to draw NGL samples for identification of gross impurities that might require a shutdown or diversion of plant production until cured. Testing procedures involve utilizing corrosion sensitive test strips (commonly copper) and color charts (Saybolt colorimeter test).

NGL delivered into a pipeline are spot sampled by the plant operator or automatically sampled on a continuous basis, depending on contract terms with the purchaser or carrier. In the case of truck or rail deliveries, samples of each load are taken. Samples are analyzed using a chromatograph similar to natural gas measurement. Constituents are reported on a volume percent basis including impurities. Chromatograph analyses often report a number of chemically distinct constituents to a far greater level than is recognized in field market arrangements. In such a case the constituents of the liquids simply have to be grouped to their market designation and totaled for settlement purposes. For example, the analysis may report h*exanes plus* or *C6+* in addition to the pentanes or C5s where a processing agreement only provides for settlement to p*entanes plus*. Here the accountant would simply add the reported percentages attributable to hexanes and pentanes together to arrive at the settlement quantity of *pentanes plus* or *C5+*.

Upon carrier acceptance, the liquids are transported to a user or market center. Market centers generally have facilities for NGL receipt, storage, and fractionation and provide standard exchange and delivery procedures to facilitate the trading of liquids (see Chapter Twelve).

RESIDUE GAS

Residue gas or dry gas is over 90 percent methane and has a heat content approximating one mmBtu per mcf at atmospheric pressure. Residue gas volume and heat content will be significantly less than the volume and heat content of the corresponding wet gas put into the plant. The *shrinkage* (or plant volume reduction (PVR) and plant thermal reduction (PTR) in processing) results primarily from (1) using gas as fuel to operate the plant, (2) extraction of the NGL and impurities, and (3) plant losses and meter differences arising from gas volumes not being measured in normal operations with complete accuracy. Extraction loss is greater for a gas stream having a high liquid content than for a stream containing less liquid. Therefore, this shrinkage factor is taken into consideration when determining each lease's share of NGL and residue gas produced by the plant.

The total volume of residue gas remaining after processing is the sum of residue gas volumes actually delivered from the plant to the producers and to gas purchasers. This volume, when multiplied by the Btu content of the residue gas, may be allocated between the leases or wells on the basis of their respective volumes of theoretical residue gas, using some factor to represent the liquids and extraction loss.

Plant operations personnel are responsible for keeping accurate records of products delivered to the plant through the plant's inlet and outlet metering systems. Also, operations reports are maintained for volumes produced and sold. If any inventories of NGL or the combined products in the gas stream are kept at the plant, inventory records must be maintained. Metering systems and various records must be accurately maintained by the plant and available for audits by producers and purchasers.

Residue Gas Allocation

In making lease settlements for residue gas collectively sold by the plant operator, a reasonable allocation must be made to each lease or field supplying gas to the plant. First, the total amount due all leases is determined. That amount is then allocated between the leases or wells on the basis of theoretical *residue gas available for sale* as calculated for each lease. The gas sales proceeds to which the appropriate percentage is applied are usually the amounts received from the gas purchasers. Some gas contracts provide that the plant owner may reduce the gross sales revenue by specified charges per mcf to cover dehydration or other services furnished by the plant to make the gas salable.

Determination of the volume of *residue gas available for sale* for a lease or well involves a number of factors. Basically, this quantity is the volume of gas received at the plant from the lease or well, less an allocated portion of gas consumed in the plant, less extraction loss, and less the volume of any residue gas returned to the producer for lease or well operations.

Using the volumes computed in the prior example for a gas sales allocation from a central delivery facility, assume that the gas streams from Leases D, E, and F enter a processing plant. Those sales allocations for Leases D, E, and F are the allocated volumes measured at the plant inlet meter (24,502, 20,960, and 26,113 mcf, respectively, in the prior example). Assume that the actual residue gas sold by the plant operator is 50,000 mcf after delivering 4,000 mcf taken-in-kind by Lease F owners.

				Residue Gas Allocation	
Lease	Inlet Volume	Theoretical Shrinkage	Theoretical Residue	Take-in Kind	Gas Sold
D	24,502	(5,289)	19,213	0	18,753*
E	20,960	(4,345)	16,615	0	16,217
F	26,113	(6,616)	19,497	4,000	15,030
Total	71,575	(16,250)	55,325	4,000	50,000

*Computed as:

$$\frac{\text{Lease D's theoretical residue of 19,213}}{\text{Total theoretical residue of 55,325}} \times 54{,}000 = 18{,}753 \text{ mcf}$$

It is possible that the volume of residue gas returned to the lease or well will exceed that lease's or that well's theoretical residue gas, which is the volume the producer may be entitled to take back to the lease or well. If this occurs, the lease or well has no *residue gas available for sale* and the excess volume may be treated as a sale of residue gas by the plant owner to the producer, and payment must be made by the producer. The plant owner's revenue from this sale must be included with revenue from the other sales in making settlements to the other leases.

If a producer is selling gas from two or more leases to the plant owner under a single contract, the contract may contain a *residue pooling* provision under which all leases covered by the contract will be considered as a single lease for the purpose of determining the volume of residue gas that the producer is entitled to have returned, regardless of the lease to which the gas is returned. Thus, if more gas is returned to a lease than the *actual residue gas remaining* for that lease, the excess would be charged against the *actual residue gas remaining* for one or more of the producer's other leases.

When residue volumes are pooled, the plant owner should inform the producer of the volumes of *actual residue gas remaining* that were transferred between leases in making the lease settlement calculation. The transfer of such volumes from a lease reduces the amount of settlement to that lease for residue gas. Therefore, the producer must make appropriate adjustments for royalty and tax purposes, as well as for the purpose of recording lease revenues and expenses.

GAS PLANT SETTLEMENT

As shown above, gas processing can be very involved. As a result, detailed calculations must be completed to determine volumes and sales proceeds of product that have been sold and volumes taken-in-kind. One of the required schedules prepared by a *gas plant accountant* is the *gas settlement statement*. The settlement statement is a verification received by the producers, or other buyers, of take-in-kind volumes and volumes and prices of products sold for each lease or well.

Gas settlement statements provide the detail for the gas producers' and buyers' accounting departments to record the sale of the products. They must include the property name, the actual residue gas and NGL, the theoretical residue gas and NGL, volume of extraction and processing loss, the volumes sold, the gpm of each product, the Btu of the gas, the prices paid per product, any deductions taken by the plant owner, and the total settlement amount for the property. A settlement statement is illustrated in Chapter Thirteen, during the discussion of accounting issues.

GAS STORAGE

In the United States, natural gas demand is seasonal with different regions having different seasons of peak and off-peak demand. In the northern states, there is a higher demand in the winter to provide space heating, and in the southern states, a higher gas demand exists in the summer to generate electricity for air conditioners. Overall, natural gas demand is higher in the winter than in the summer. Gas production during seasons of low demand may be stored in special underground reservoirs for use in months when demand peaks. These gas storage facilities are typically downstream on the pipeline system and temporarily store gas that came from numerous fields.

Traditionally, gas storage is defined as that series of operations whereby a quantity of production is injected into an underground depository (such as a depleted oil/gas reservoir) to meet later demand. Depleted reservoirs were historically used for gas storage. However, leached salt dome structures, as used for the crude oil stored in the Strategic Petroleum Reserve, have been used in recent years in the areas of the country that have underground salt domes, like the Gulf Coast.

Increasing storage capacity in the salt dome is done by pumping in fresh water that dissolves the salt walls of the storage area, making it easier and less expensive to expand storage capacity than using depleted reservoirs. Depleted reservoirs, while attaining a high rate of withdrawal, take a relatively long time to fill. As such, it generally takes much of the year to fill them for a winter withdrawal. Salt dome storage facilities are usually capable of more rapid filling, commonly providing for a cycling period of one month or less.

Limited pipeline capacity from the producing area to the market restricts delivery capacity during peak demand periods. This restricted ability to move gas provides an incentive for producing gas at a relatively constant rate throughout the year and storing as far downstream as practical the produced gas that exceeds current demand.

Historically, the storage function was performed primarily by pipeline companies. The pipeline company used to charge one inclusive transportation fee that paid the cost of transportation and other pipeline company functions, such as compression charges, withdrawal charges, matching buyers and sellers, intrahub transfer fees, temporary storage (called *banking* or *parking*), and long-term storage. With the importance of the natural gas market in the last several years, the structure of the market and the rules have changed, primarily due to FERC Order No. 636

(issued on April 8, 1992), which requires pipelines to *unbundle* transportation services from other functions and charge fees for specific services performed. FERC Order No. 636 has caused the pipeline companies to become *transporters* of gas and caused producers and other sellers to sell gas predominantly to the end user or LDC. This, in turn, has encouraged producers, major end users, and LDCs to seek storage rights, as needed, in order to meet their new sales commitments.

NGL STORAGE

A gas processing plant owner may accumulate NGL inventories that need to be stored on site. The most common liquids storage is a one- to three-day supply of NGL production stored in above ground *bullet* tanks (the industry term which also is descriptive of the tank shape). The liquids can be transported from the storage facilities by a connection to an NGL pipeline or by trucks or rail cars loading at plant terminals. Underground storage is also used for NGL, either as a mix of products or a *purity* product (which refers to the pure product or the liquids that meet the specifications of the purchaser).

Many underground storage facilities are located near fractionation plants and wholesale market delivery or consumption points. In these circumstances, one method frequently used in determining the price paid to the producer is to pay, or *make settlement*, in the month in which the NGL is produced and stored, based on prices received from actual sales during the current month or during the last preceding month in which sales were made. Depending on company policy and contract terms, adjustments may or may not be made at a later date for the difference between the price initially used for settlement purposes and the price received at the time the NGL is withdrawn from storage and sold.

Another method is to defer settlement until the NGL is withdrawn from storage and sold. The settlements are based on the prices actually received from the sales. This method requires that the plant owner maintain monthly records of the products placed in storage in order to ensure a proper allocation between leases at the time of withdrawal. Sales from storage are usually allocated on a first-in-first-out basis.

Chapter Twelve

MARKETING CRUDE OIL, NATURAL GAS, AND NGL

Once oil and gas have been discovered, commercial viability has been determined, production equipment has been installed, and treating and processing have been completed to bring these commodities to a marketable state, the next step is to market the product. Oil, natural gas, and NGL are each fungible commodities whose sales value is not greatly enhanced by product differentiation using colorful packaging and media advertising. Their prices are no longer subject to federal price controls, and the markets have become very volatile since the early 1980s. Marketing and price are largely influenced by the product's physical quality, potential customers, location of product and customer, and supply and demand for the commodity.

This chapter discusses marketing arrangements from the producer to the end user. Price determination in the United States is illustrated, and energy-related financial products are introduced.

CRUDE OIL MARKETING

OIL MARKETING FACTORS

Summarized below are the general factors in marketing crude oil in the United States:

Physical Quality. Crude oil varies in density (measured in degrees of API gravity) and sulphur content. The greater the density (i.e., the lower the API gravity) or the greater the sulphur content, generally the lower the value and price of the crude.

Potential Customers. Crude oil is ultimately sold to crude oil refiners who separate and process the crude oil into refined products, such as gasoline and diesel fuel, as shown in Chapter One, Figure 1-10. The U.S. refinery business is competitive, but some three dozen companies own 90 percent of the country's refining capacity. Some refineries can process only certain types of crude oil or are most profitable refining a given type of crude oil. Generally refineries are most profitable if the quality and type of crude oil are relatively constant for several months or years. Given the variations in crude oil gravity and sulphur content versus the needs of individual refineries, crude oil is not as fungible as dry natural gas.

Crude oil can be transported from the lease to the refinery via truck, barge, rail car, tanker, or pipeline. Consequently, crude oil can be sold at the lease site to refiners that arrange for transportation to the refineries or sold at the lease site to other companies in the business of purchasing crude at well sites and transporting it for resale to refiners.

Location. Transportation costs and local supply versus local demand create price differences based on general locations. For example, the *wellhead value* of crude oil produced on the North Slope of Alaska and transported to market via the Trans Alaska Pipeline System and ocean tanker is far less than the wellhead value of crude oil of similar quality produced near the giant refineries on the Texas/Louisiana Gulf Coast.

Supply Versus Demand. The United States produces approximately 40 percent of the crude oil it consumes. Consequently, oil produced in the U.S. has a ready U.S. market. Unlike natural gas, U.S. crude oil production is not curtailed by seasonal drops in demand.

TYPES OF MARKETING ARRANGEMENTS

Several typical arrangements for marketing crude oil follow:

- A royalty owner typically allows the working interest owners to market the lease's entire production and arrange for the royalty owner to receive its share of sales proceeds rather than take the royalty interest share of oil-in-kind and market its own oil.
- Joint venture nonoperators also have the right to take their share of oil in-kind and market their own share of oil, but typically allow the operator from year-to-year to market the venture's gross production.[29]
- E&P companies, particularly large operators, may employ individuals called *crude oil marketers* (sometimes called *crude oil traders*) to market the oil production. The marketer's goal is to negotiate the best possible contract price for the produced oil.

[29]Each joint venture owner's right to take oil-in-kind is an important joint venture characteristic that helps avoid classification of the venture as a corporation subject to corporate income taxes and the venture owners as corporate shareholders receiving taxable dividends.

Some companies have formed separate divisions or subsidiaries to market their oil production and the oil of other producers.

- Obtaining the best price may entail not simply selling the crude oil but at times exchanging the produced crude oil for other crude. For example, Company A produces California crude and owns a Texas refinery. Company B produces Texas crude and owns a California refinery. Companies A and B may agree that Company A's oil production will be given to B for B's California refinery in exchange for a similar volume of Company B's Texas oil production being given to Company A for A's Texas refinery. Company A may pay Company B, or vice versa, an exchange differential to adjust for differences in the exchanged crude oil's qualities, local market prices, or transportation costs.
- In addition to selling oil to a refiner, E&P companies may market the crude oil by selling to a nonrefiner, commonly called a *crude oil trading company*, which may be a producer's subsidiary but is often a marketing agent independent of producers and refiners. The crude oil trading company's key employees who negotiate the purchases, sales, and exchanges of crude oil are called *crude oil traders.*

Sales arrangements are typically expressed in written, negotiated agreements containing the names of the parties to the contract, the date of the agreement, the property name and location, transporter, the sales volume or production time period, the delivery point, the price, and some geographic, physical, or chemical characteristics of the oil. The typical parties to a contract are the oil producer or operator, as seller, and a refiner or oil trader, as purchaser. The agreement may refer to a set of general terms and conditions (GTC) specifying remedies if the contract is not followed. Most commonly, the parties will agree to GTC written by one of the major oil companies and will specify any modifications to those terms in the contract.

Three types of basic crude oil sales arrangements exist: (1) evergreen sales contracts, (2) spot sales contracts, and (3) exchange contracts. A month-to-month sales contract, called an *evergreen sales contract*, generally refers to a contract negotiated for an initial period of a month and renewed each month until either party cancels the agreement.

In the current era of oil price volatility, most evergreen contracts reflect a negotiated price per barrel based on a fluctuating market price, an indexed price, or a fixed price plus adjustments or escalations. Some currently used crude oil pricing structures will be discussed in the next section of this chapter.

A *spot sales contract* consists of the short-term sale of a stated volume of production for a stated short-term period (such as a few days or a month or two) for the sale of crude oil based on a negotiated price between the buyer and seller. For example, the parties may agree to buy/sell 100 barrels per day of South Texas Light crude oil from the Ralph #1, located in Hidalgo County, Texas, for each day of a specified month at $23.50 per barrel. Once the time period has ended or the specified sale has occurred, the contract ends.

Evergreen and spot sale contracts allow producers to change oil purchasers on short notice, but most producers rarely do so.

The third type of sales arrangement is the *exchange* (sometimes referred to as a buy/sell arrangement), in which producers will exchange crude oil production for another stream of oil production as in the previous example of two companies exchanging Texas crude oil for California crude.

U.S. OIL PRICING

Each delivery (referred to as a *run of oil*) from the lease storage tanks has its volume and date of withdrawal recorded on the run ticket or a report from the LACT unit. The crude oil is priced separately on the basis of the date of removal from the tanks. The sales contract specifies the price to be used for the indicated time period. The values of all the runs during the month are accumulated, and settlement is made monthly by the purchaser.

As mentioned in the previous section, prices may be based on a fixed, stated price at the beginning of the contract. However, most crude oil contracts are negotiated a month or more before the transactions take place, and they may tie the oil prices to fluctuating reference prices (such as published posted prices or index prices) to approximate the current market price as the oil is delivered. Some contracts may state a minimum floor or maximum ceiling in conjunction with the fluctuating reference price for added protection in trying to negotiate the transaction price.

Price adjustments (called *differentials, bonuses, deducts, premiums*, or *discounts*) from a few cents to a few dollars per barrel from the fluctuating reference price may be negotiated. A premium might be negotiated for large volumes of crude oil or crude oil that is favorably located with respect to the purchaser's needs. Producers or brokers that agree to sell all of their oil production, or all of their production from a certain geographical area, often may command a premium from the purchaser.

A discount may be negotiated to compensate the buyer for oil in a remote location that requires higher transportation expenses. Discounts may also be imposed for impurities, such as sulphur content.

In exchange contracts, price adjustments are commonly used for the difference in location or when a less valuable crude oil is exchanged for a higher value crude oil.

Gravity adjustments are the most common type of premium or discount for crude oil. As previously discussed in Chapters One and Eleven, heavy crude oils (typically with an API gravity below 20º) have less value than light crude oils (typically above 35º API), which yield more gasoline and other valuable products. Adjustments based on the gravity of the oil will be discussed in further detail in the next section on calculating prices from posted price bulletins.

During this complicated process of contract negotiation, oil marketers are attempting to make the most favorable settlements for their companies in a historically volatile oil price market. To this end, marketers may have their companies purchase or sell various financial instruments (futures contracts, etc.) in an attempt to protect their companies from the pricing risks inherent in the oil market. However, most holders of futures contracts close out their position by taking the exact opposite position rather than being obligated when the contract expires to receive or deliver physical barrels. For example, assume that an E&P company has a futures contract to sell 1,000 barrels of crude oil in July 2000 at $20 per barrel. The company may obtain a futures contract to receive 1,000 barrels of crude oil, thereby *netting* the two contracts to close out the position. Crude oil futures contracts are referred to as *paper barrels*, distinguished from physical barrels called *wet barrels*. The futures contracts generally provide for oil to be delivered at a specified tank farm or refining facility at some future date and price. The futures crude oil market consists of oil producers, refiners, and third-party traders as well as many other investors who are speculating on oil prices.

A buyer of sweet crude oil futures on the New York Mercantile Exchange (NYMEX or MERC) is committing to buy West Texas Intermediate crude oil (or similar sweet crude) at Cushing, Oklahoma, at a stated price when the futures contract expires. The futures buyer can arrange to receive (or a futures seller can arrange to deliver) a different crude oil at a different location by an *exchange of futures for physicals* (EFP). An EFP is an agreement whereby a futures obligation is exchanged for a physical obligation. The futures buyer gives its futures contract to another party (with NYMEX recording the change in ownership) and commits to buy other crude from that party at an agreed-upon price, taking into account the unrealized gain or loss on the futures contract assumed by the other party. Futures contracts and price hedging are discussed further in Chapter Thirty-Two.

Posted Price Bulletins

Posted price bulletins (also referred to as *crude oil price bulletins*, *price bulletins*, or *posted prices*) are published bulletins listing prices that a particular purchaser may pay for various types of oil and contain adjustment factors for crude oil generally above and below an API gravity of 40°. Posted prices originate from the early oil days when purchasers posted their price lists on a fence post in the oil fields as an offer to buy. Today's posted price bulletins serve more as an index of prices than a solicitation to buy. Posted prices are tied to many factors, including the physical quality of the oil, the other prices in the same geographical area, the location of the product to the buyers, cost and risk of transport and ownership enroute, supply versus demand, past history of prices, and the NYMEX's oil futures market.

Price bulletins vary in format, but generally contain the following information (as illustrated in Figure 12-1):

- A listing of crude types[30] by geographical area or state (sometimes a county or even a particular field) and a distinguishing chemical or physical characteristic (sour, intermediate, and sweet refer to the sulphur content; light and heavy refer to the API gravity);
- The posted prices for each type of crude at a stated benchmark API gravity (generally 40°);
- The bulletin number and the effective date of a change to the posted price contained in the column headings; and
- A gravity adjustment scale of price *decrements* (occasionally *increments*) for crude with an API gravity below (or above) 40°.

[30]The words *type*, *area*, *grade*, and *quality* may be used interchangeably or may be defined differently, depending on the individual using the term. This chapter refers to the geographical location and physical or chemical characteristics used in defining the crude oil.

Figure 12-1: Big Oil, Inc. Posted Price Bulletin

Big Oil, Inc.
P.O. Box 2842
HOUSTON, TEXAS 77002

DECEMBER 1999

CRUDE OIL PRICE BULLETINS NO. 99-198 thru 99-207

Effective 7:00 a.m. on the effective dates shown below, subject to change without notice and subject to the terms and conditions of its division orders and other contracts, Big Oil, Inc. will pay the following prices per 42-gallon barrel of marketable crude oil and lease condensate ("crude") of the following types and grades purchased by it and delivered for its account into the custody of its authorized carrier or receiving agent. The prices apply to quantities of crude derived from the use of 100% tank-tables or as measured by approved automatic custody-transfer facilities, with full deduction for basic sediment, water, and other impurities and corrected for temperature to 60°F. The prices may also be subject to marketing adjustments and/or deductions for trucking, transportation, and other charges where applicable.

All crude shall be direct liquid hydrocarbon production from oil or gas wells in its natural form and shall not contain refined products or indirect liquid products. Indirect liquid products are those resulting from operations in natural gasoline recovery plants and gas recycling plants. Seller warrants that the crude delivered to Big Oil, Inc. shall be of marketable quality and fit for normal refinery use. Seller shall be liable for any losses or damages suffered by Big Oil, Inc. arising out of seller's breach of above-mentioned warranty.

BULLETIN NO.:	99-204	99-205	99-206	99-207		
EFFECTIVE:	12-23-99	12-23-100	12-23-101	12-23-102		
	PRICE $/BARREL	PRICE $/BARREL	PRICE $/BARREL	PRICE $/BARREL	ADJ SCALE	Monthly Average
West Texas/New Mexico Intermediate	23.00	23.50	24.00	23.75	E	23.2258
West Texas/New Mexico Sour	20.00	20.50	21.00	20.75	F	20.2258
West Central Texas	23.00	23.50	24.00	23.75	E	23.2258
North Texas Sweet	23.00	23.50	24.00	23.75	E	23.2258
North Texas Sour	21.25	21.75	22.25	22.00	F	21.4758
Texas Gulf Coast Light	21.75	22.25	22.75	22.50	E	22.3145
Giddings	21.75	22.25	22.75	22.50	E	22.3145
Oklahoma Sweet	23.00	23.50	24.00	23.75	E	23.2258
Oklahoma Sour	20.00	20.50	21.00	20.75	F	20.2258
Wyoming Sour	19.50	20.00	20.50	20.25	F	19.7258

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When calculating the price to be received, premiums or discounts may be added or subtracted from the posted price, depending on the difference between the bulletin's stated benchmark API gravity and the actual API gravity of the oil delivered. Lower-gravity oil (typically with an API gravity below 40º) and extremely high-gravity oil (an API gravity over 45º) will generally receive a deduct adjustment. In some instances, oil with gravity in excess of 40º API (up to a stated maximum acceptable) receives a premium adjustment.

Figure 12-1: Big Oil, Inc. Posted Price Bulletin, continued

GRAVITY ADJUSTMENT SCALE

The price for a given grade of crude is to be adjusted for gravity by subtracting the amount shown on this table.

	Deduction, $/Bbl.						
Gravity °API	**A**	**B**	**C**	**D**	**E**	**F**	**G**
40 & Above (1)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
39-39.9	0.02	0.00	0.02	Below 40° Deduct $0.015 per 0.1° API	0.02	0.00	0.00
38-38.9	0.04	0.00	0.04		0.04	0.00	0.00
37-37.9	0.06	0.00	0.06		0.06	0.00	0.00
36-36.9	0.08	0.00	0.08		0.08	0.00	0.00
35-35.9	0.10	0.00	0.12		0.10	0.00	0.00
34-34.9	0.12	0.00	0.16		Below 35° Deduct Additional $0.015 per 0.1° API	0.00	0.00
33-33.9	0.14	0.00	34.0 to 20.0 Deduct Additional $0.02 per 0.1° API Below 34°			Below 34° Deduct $0.015 per 0.1° API	0.00
32-32.9	0.16	0.00					0.00
31-31.9	0.18	0.00					0.00
30-30.9	0.20	0.00					Below 31° Deduct Additional $0.02 per 0.1° API
29.29.9	0.22	0.00					
28-28.9	0.24	0.02					
27-27.9	0.26	0.04					
26-26.9	0.28	0.06					
25-25.9	0.30	0.08					
24-24.9	0.32	0.10					

(1) Big Oil, Inc. reserves the right to refuse crude in excess of 45° API. Deduct 1.5 Cents/0.1° API for gravities above 45.0° API.

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For example, the Donald James Refining Company negotiates to purchase the December 1999 West Texas/New Mexico Intermediate production from the Douglas #2 lease using the Big Oil, Inc. average monthly posted price plus $.25/bbl.

Assume that the oil that is delivered to the Donald James Refining Company has a 32.5° API gravity. The *adjustment scale* column refers to the gravity adjustments in column E, located on the second page of Big Oil, Inc.'s bulletin. The deduction subtracted from the posted price would be $0.48/bbl, calculated as follows:

Deduction for 40.0° - 35.0°:	$0.10
Additional for below 35° :	
35.0° - 32.5° = 2.5 whole degrees	
2.5° x 10 = 25 tenth degrees	
25 x $.015 =	0.38
Total deduction per barrel	$0.48

In most cases the oil is purchased at the average price for the month adjusted for the gravity. Assuming the contract for the Douglas #2 production states the oil is to be sold at the monthly average price, the price is calculated as follows:

December 1999 monthly average	$23.23
Less the gravity adjustment	(0.48)
Plus the bonus	0.25
Total price per barrel	$23.00

If the contract states the production is sold as *equal daily quantities* (EDQ), the crude oil is considered to be delivered in equal quantities during each day of the month. EDQ can be specified on a contract even though the crude is picked up by truck, which is normally priced at that day's posting. LACT units will always use the EDQ method. Assuming that the December 1999 production for the Douglas #2 was 3,100 barrels, the EDQ would have been 100/bpd. The price would be calculated using the appropriate daily price from the price bulletin adjusted for the gravity and bonus. To calculate the total sales for the month, multiply each daily-adjusted price by the EDQ. For example, the adjusted price for December 23, 24, 25, and 26 is $23.00 - $0.48 + $0.25, i.e., $22.77. Revenues for those four days are $22.77 x the EDQ of 100 x 4 days = $9,108.

Other Reference Prices

Other prices referenced in the sales contract may incorporate the daily closing NYMEX crude oil futures prices plus a premium or discount. The contract parties may agree to use the average of each closing futures price for every day in the month that the NYMEX is open and trading to determine the sales price of the oil. The contract should clearly disclose the particular details of the reference pricing determination, including the averaging formula or dates to be used and the name of the particular source used in quoting the NYMEX prices (such as *The Wall Street Journal*, *Bloomberg's Business News*, or *Reuters America Inc*.) as various price quotations may include or exclude the final one or two prices of the day in arriving at their closing price.

Various publications poll oil traders or other sources as to the prices at which they recently bought or sold oil. These publications may cull out the highest and lowest prices quoted by the group polled and then compile and publish an index of crude oil prices. The oil sales contract should clearly state the index used and include any premium or discount adjustments that are added to the index price.

NATURAL GAS MARKETING

Natural gas has been a fuel supply in the United States for over 180 years. In 1816 the Gas Light Company of Baltimore, the forerunner of today's Baltimore Gas & Electric Company, was formed and granted a franchise and a contract to light Baltimore's streets. In 1817 the first gas street lamp in the United States went into service. In 1840 gas cooking originated in England, and exhibitions in the United States boasted gas stoves.

Local distribution companies (LDCs), i.e., public, trust, or investor-owned utilities, started building the basic infrastructure by laying gas distribution systems within their service areas and manufacturing gas from bituminous coal or wood. In the first half of the 20th century, long-distance pipelines were constructed from areas where gas was produced to areas where it was consumed. Many pipelines were constructed as an outgrowth of the war effort in the 1940s.

As mentioned in Chapter One, natural gas has many uses, including home heating, cooking, air conditioning, chemical feedstock, and electric power generation. It will gain more uses as a result of compliance standards of the Clean Air Act of 1990. Some cars and trucks run on compressed natural gas. Some city buses run on LNG (gas liquified by chilling). Demand is growing for gas as a fuel for generating electricity. Various companies have or are building pilot gas-to-liquids (GTL) plants to convert natural gas to liquid fuels, such as gasoline and diesel fuel, that have little or no sulfur contaminants.

Understanding the history of natural gas regulation and the deregulation of pricing will provide some insight into the current natural gas marketing arena.

HISTORY OF NATURAL GAS REGULATION

Natural gas, today considered a premium, clean-burning fuel, was viewed a hundred years ago as an unwanted commodity. Producers were disappointed when they drilled what turned out to be a gas well rather than an oil well. The skies over Texas were at times lit up at night by producers flaring unwanted gas. Gas was flared for the purpose of preventing an explosion with volatile unburned gas. While gas may have been a waste product to early producers, it eventually became a necessity in heating millions of U.S. homes and providing energy and feedstock for various industrial and manufacturing companies. The expanding natural gas markets for local gas utilities served by relatively few interstate pipelines created fears of monopolistic power that warranted government oversight and regulation.

By the early 1900s, some states had enacted laws to form public service commissions to oversee the local gas and electric utilities. The federal government began regulating interstate gas pipelines by enactment of the Natural Gas Act of 1938. Regulation of utilities at the state level has been around for a long time. For example, the Public Service Commission of Maryland was formed in 1910. Recent federal deregulation of interstate transport and commerce of natural gas leaves state level regulation the most active in today's gas market.

Natural Gas Act of 1938

The Natural Gas Act of 1938 sought to protect the public from the possibility of monopolistic pricing and service practices by the few large gas pipelines that carried gas between states. It also regulated pipelines that extended from federal leases in the Outer Continental Shelf to shore or inland facilities. The Natural Gas Act of 1938 created the Federal Power Commission (FPC) to regulate the construction, operations, and rates of interstate commerce in order to ensure that the public convenience and need were being served. Permission from the FPC had to be sought in advance to construct and operate new pipeline facilities, add sales arrangements, and charge rates for various sales, transportation, and storage services. The Natural Gas Act of 1938 did not seek to regulate the price of natural gas at the wellhead.

Phillips Decision

The 1954 United States Supreme Court's Phillips decision, contradictory to the Natural Gas Act of 1938, expanded regulations and price controls to cover natural gas wellhead sales by the producers to interstate pipelines. The Phillips decision did not extend these regulations to the intrastate gas market, causing producers to shift sales from the regulated interstate market to the unregulated intrastate market during the 1970s when booming oil prices raised the value of natural gas as an alternative energy source.

Shortages

After the Phillips decision, producers who were able to sell the same volume of natural gas in the intrastate market as the regulated interstate market did so and generally received higher prices in addition to eliminating the administrative burden that the regulations imposed on the interstate market. With producers avoiding the interstate market and flooding the intrastate markets, supply problems began to develop in the interstate markets where demand was booming for artificially cheap interstate gas, especially in the nonproducing states of the industrial belt.

Recognizing real shortages of supplies to the interstate market, the FPC (renamed the *Federal Energy Regulatory Commission* or *FERC* in 1978[31]) started approving *just and reasonable* sales rates (which reflected higher wellhead prices) generically based, first under area-wide rates (prices approved for gas produced from specific areas such as the Permian Basin) and then by nation-wide rates, which established the same rate structure regardless of the geographic region where the gas was produced. These area and national rates replaced the practice of approving rates for each individual contract. Still, the regulated prices of interstate gas were, on average, well below gas prices in the intrastate market.

Beginning in the early 1970s, industrial customers outside of producer states began to experience gas curtailments. After shortages during the winter of 1976-77 created emergency situations in the Ohio Valley and other parts of the northern U.S., Congress passed legislation designed to temporarily alleviate gas supply shortages in the interstate market.

Natural Gas Policy Act

Recognizing some of the problems caused by dual markets, Congress passed the Natural Gas Policy Act (NGPA) in 1978. The NGPA was a

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[31]The FERC is the five-member commission within the Department of Energy that regulates and determines tariffs for the interstate transportation and sale of natural gas, the construction of pipeline facilities, the pipeline transportation of oil, and the transmission and sale of electricity.

complex piece of legislation designed to deregulate the price controls on certain categories of gas (29 categories were defined by well spud date, interstate or intrastate, onshore or offshore, etc.), immediately raise the prescribed price on other types of gas, and phase out price controls and governmental approvals for sales on a variety of categories of gas over time.

Substantial portions of gas continued to be sold to interstate pipelines at federally mandated *maximum lawful prices* (MLP) well below intrastate free market prices. Consequently, the interstate gas market bid up the price of some unregulated gas as high as $10/mmBtu. This gas, priced above its true market value, could be averaged with less expensive gas by interstate pipelines and the LDCs served by them. These artificially high prices, coupled with high prices for deregulated gas, caused a tremendous drilling boom. Within a short time the drilling activity created a much larger reserve and delivery base of natural gas than had previously existed. The price of unregulated gas climbed in the interstate market, but demand did not. In fact, as a result of higher gas prices, alternate fuels such as residual fuel oil began to displace gas. The gas supply in both the interstate and intrastate markets increased at the same time that the demand for natural gas decreased. This led to the gas *bubble*, or surplus, whereby market forces have caused natural gas to be produced for the past decade below productive capacity at various times of the year and from various wells within the U.S.

The pipelines, both interstate and intrastate, tried to keep their markets by lowering the price of natural gas to their suppliers, often by refusing to honor previously negotiated higher-priced contracts. This led to the price of gas falling for the producer but not necessarily to the user. After a while it became apparent that the price to the users of natural gas would have to be competitive with that of alternate fuels in order for the user to remain a gas customer.

Federal Deregulation

Through a variety of FERC orders starting in 1983, which included FERC Orders 436 and 500, pipelines became less involved in the business of purchasing gas from their suppliers and reselling to their customers, i.e., the *merchant* function. Rather, pipelines became more involved in the transportation function wherein pipelines transported the gas for a fee. In this way, a producer or some other entity could sell gas directly to customers. At the same time, maximum lawful prices and regulations applicable to producer sales gradually came to an end. Today, any willing buyer and seller can make a deal for the purchase and sale of natural gas without getting prior federal governmental approval on service or rates.

Over time, natural gas contract pricing mechanisms have changed. Previously, governmental regulatory policy set the maximum rates that producers could charge for gas. Now the price paid directly for the gas is the result of negotiations between the parties. Since the LDC segment of the industry is still regulated at the state level, the LDC is still subject to justifying the rates that it pays for gas purchased in connection with transportation.

Interstate pipelines historically performed the various market functions of transporting, marketing, and storing natural gas. These functions were included (or bundled) in a single rate charged by the pipeline. FERC Order 636, issued in 1992, ordered that the services that could be previously purchased from the pipelines for an all-inclusive fee must be *unbundled*, whereby each pipeline user contracts for the exact services they require. Cross-subsidization of the pipeline services was no longer permitted. It is important to note that interstate pipelines are still subject to regulation by the FERC for such things as rate approval, operating tariff approval, and construction of facilities.

Today, it is generally conceded that the supply and demand of natural gas are balanced by free market prices and more efficient use of pipeline and storage services enabled through deregulation. This sea of change in the natural gas industry has caused a multitude of problems that are still in the process of being resolved. Some of the problems are of a regulatory nature; some concern market dislocations. It is also important to note that many of the concerns, which were resolved on the federal level with the issuance of Order 636, have now been shifted to the state level. One issue facing residential users is that historically the LDC was able to use industrial customers to subsidize, to a degree, the true cost of serving residential customers. The evolving gas market is eliminating cross-subsidies. Accordingly, in reacting to changes brought on by Order 636, LDC and state regulatory commissions will need to resolve social issues regarding subsidization of residential users.

GAS MARKETING FACTORS

Summarized below are some general factors in marketing natural gas:

Physical Quality. As described in Chapter Eleven, produced natural gas can be processed if necessary to extract NGL and remove impurities to provide *dry* residue natural gas that is over 90 percent methane. Dry natural gas is more fungible than crude oil and can be more readily combined and transported in a highly developed U.S. pipeline system that delivers dry gas from the well or processing plant to millions of end users such as individual residences.

Potential Customers. Due to the fungibility of dry natural gas and due to the vast network of gas pipelines, the FERC has allowed pipelines to act as transporters (not as gas purchasers and resellers) and allowed producers to sell gas to local gas utilities and even the utilities' former customers. The gas producer now has thousands, if not millions, of potential customers. It is impractical for the typical gas producer to sell to thousands of customers. So several large gas marketing companies are emerging to replace gas pipelines in performing the merchant function of buying gas from producers and selling to end users.

Location. Since gas is transported almost exclusively by pipeline in the United States, location plays a greater role in gas marketing than in crude oil marketing.

Supply Versus Demand. Unlike crude oil, annual U.S. gas productive capacity approximates annual demand, and demand is substantially less in the summer than in the winter when home heating with gas is highest in many parts of the country. A small percentage of U.S. demand is met with imported Canadian gas. These aspects of supply and demand mean that, unlike oil wells, many U.S. gas wells produce below their capacity and may even be shut-in at times during a year. Alternatively, wells may produce at capacity in the summer, but the gas is transported to underground gas storage facilities for use in the winter to meet peak demands when gas prices are expected to be higher.

Futures Contracts. As with crude oil, buyers and sellers of natural gas can hedge the price of gas using futures, options, or some other derivative product as discussed more fully in Chapter Thirty-Two.

GAS MARKETING STRUCTURE

The sale of natural gas has changed dramatically in recent years. Until the early 1980s, as a result of regulations and the development of a *spot sales market*, volumes were predominantly sold under long-term contracts to pipelines, which then resold the gas to an LDC. In today's new gas market structure, producers and third-party marketing companies are making inroads to sell gas directly to the end user markets.

Producers

In order to realize revenue, the producer will sell some or all of its natural gas production to a third-party gas marketer or contract with a gatherer, processing plant, or pipeline to transport the gas to downstream customers. A producer may also use some of its natural gas in its own facilities, such as field equipment or even a company-owned refinery. It may even purchase additional gas supplies from other sources to add to its own supplies.

Royalty owners and joint venture non-operators typically have the right to take their share of produced oil and natural gas in-kind but often choose to have the joint venture operator sell the gas on their behalf. This practice is less common among working interest owners for gas than oil, giving rise to a problem called gas imbalances, addressed in Chapter Fourteen.

The monthly process of selling the next month's gas, negotiating prices, and determining the sales and delivery points occurs prior to the close of the NYMEX futures contracts sales, which is generally five working days before the end of the month. The week before the closing date, more commonly the two days before the closing date, called the *bid cycle* (or *bid week*), is when the majority of these deals are arranged.

If the producer has not sold the gas at the wellhead, any pipeline transportation that is needed to sell the gas downstream must be scheduled (referred to as the *nomination* process) with the pipeline company. The parties to the transportation process are called the shipper and transporter.

A producer, marketer, processing plant, LDC, pipeline, or other party that retains title to the gas or has contracted with the producer to oversee the shipment of the gas is called the *shipper*. The gatherer, pipeline, processing plant, LDC, or any other transportation party responsible for physically moving the gas is called the *transporter*. The shipper notifies the transporter of the quantity of gas to be shipped (i.e., generally the mmBtu of gas per day), the dates when the gas will be shipped, the receipt point (i.e., meter) into the pipeline, the delivery point where gas will be taken by a customer, and the volume to be delivered to the customer.

The transporter has the responsibility to confirm with the producer and its customers the respective nominated quantities and terms. The nominations are estimates of the gas flow for the given day and month. The actual gas flow will most likely be different because of pipeline pressures, fuel usage, pipeline loss, and other conditions inherent in producing gas. Therefore, it is important for each party to maintain accurate volumetric records of the transactions as the volume variances must be recorded and resolved at a delivery point (where the title transfers from the producer to the transporter/purchaser) as determined by contract provisions.

Marketers and Marketing Companies

Marketers and marketing companies are middlemen in the disposition of natural gas. A true gas marketer is neither a physical producer nor a user of natural gas; it purchases gas for resale much like a crude oil trading company buys and sells crude oil. A marketer may add value to the disposition of service by providing aggregation of supplies and markets and by creatively using available transportation services and storage.

An LDC historically purchased its gas supply from a pipeline company, transported it, and resold it locally to various retail classes of customers. Currently, an LDC may buy gas directly from producers and other third-party marketers and resell it to residential, commercial, and industrial users, including electric power generators. In many areas there is a trend toward eliminating the merchant function of the LDC or limiting the LDC merchant function only to small commercial and residential customers, who because of their small size do not purchase directly from the producers.

End Users

End users of gas have been historically divided into three categories: residential, commercial, and industrial. A fourth category now encompasses electric power generation, previously included in the industrial sector.

Residential usage, consisting primarily of home heating, is largely weather-dependent. A household may also use small amounts of gas in stoves, clothes dryers, water heaters, and other appliances. The residential segment continues to purchase gas from the LDC, although the future will probably see some residential users able to purchase gas from other third-party (non-LDC) marketers.

Shopping centers, office buildings, restaurants, and small stores are all examples of commercial users. These customers have traditionally purchased gas service from LDC suppliers, but they are now actively moving to new gas marketing suppliers, such as third-party marketing companies, to supply their gas service.

Industrial users comprise the largest segment of the natural gas market. Gas can be used as a feedstock or used directly to fuel on-site boilers and other machinery. Industrial customers have created the most competitive price market due to their newfound sophistication in the new gas market, and they are the segment of users most likely to have alternate fuel capability.

GAS CONTRACTS AND AGREEMENTS

There are several types of agreements used in connection with gas marketing. They include gas purchase and sales agreements, gas gathering agreements, gas transportation agreements, gas processing agreements, and management services contracts. Each general type of agreement is discussed below (gas processing was discussed in Chapter Eleven) with commonly used variations pointed out.

Purchase and Sales Agreements

Spot sales contracts, as discussed in the oil marketing section, are similarly used for sales of gas. The spot contract for gas sales is a brief document typically covering sales for a period of up to one month, although longer periods of time may also be covered. Most contracts have an evergreen clause that allows the contract to be renewable automatically beyond the primary term. The contract may be a shell form that leaves the price, volume, delivery point, and term open for agreement. Further, these contracts historically contain no penalty for nonperformance by either party but provide for *best efforts* performance (of an *up to* quantity), a phrase with little significance as to performance, or specify liquidated damages for nonperformance.

Term contracts are generally longer-term contracts, one month or more, that contain the negotiated, detailed contract provisions, such as price, volume, delivery point, contract term, and any additional elements, in the body of the contract. A distinction between term and spot contracts also may arise from the performance obligations of the contracts.

In the term contract's quantity provision, it is common that a maximum daily quantity be provided that specifies the amount which the seller must be willing to make available each day during the contract term. The buyer's requirement to take, if not 100 percent of the maximum daily quantity, may be specified prior to each month by a notice to be provided by buyer to seller. While the quantity is normally a flat daily amount to be taken each day throughout the month, it could be a variable amount. In an extreme case, the seller may be required to have the maximum daily quantity available on any day the buyer wishes to purchase it, but the buyer may be obligated to take only minimal amounts throughout any month through the contract term. While this is the subject of substantial negotiations, it is also reflective of the buyer's need to serve specific target markets and uses.

A brief description of some of the more important contract terms and provisions are provided below.

Delivery Point. The delivery point is the location immediately after a specified gas meter (at the lease, on a gathering system, on a pipeline, or at a hub) where the gas is deemed delivered to the buyer, who takes title and ownership responsibilities at that point.

Pricing. The pricing provisions contained in spot sales contracts are usually very simple. There is a specific price set forth for the sale of a specific gas quantity during a specified limited time, usually no more than one month.

Some long-term contracts, particularly very old contracts, may provide for fixed or specified prices. Fixed pricing has been frequently used to lock-in gas supply economics on projects, such as co-generation plants or power generation projects. Pricing provisions may allow for price redetermination allowing the parties to renegotiate the price at specified points in time. Frequently, the parties negotiate a fixed price that changes with escalators, inflation indicators by the government, or prices of alternate fuels. Commonly used escalators include using a scheduled percentage change or a negotiated fixed price schedule or tying the increase to an inflation factor (e.g., the Consumer Price Index).

Absent a specified price, the contract should clearly provide the fluctuating reference price, or index price and any premium or discount to the index chosen. Currently there are some 150 different index prices found in such periodicals as *Inside F.E.R.C.'s Gas Market Report*, *Natural Gas Week*, and *Natural Gas Intelligence Gas Price Index*.

Term. The term of a gas contract is the length of time the gas contract is in effect. Frequently the contract will terminate after some fixed period. However some contracts have an evergreen provision, which functions the same as described in the oil marketing section, in which the contract is in effect until one of the parties cancels the contract by giving notice within a prescribed time period.

Payment. The payment provisions of a contract contain the timing and manner in which the seller is paid for the gas. Payment can be made by check or wire transfer. Since sales data and pipeline data (measurement and transportation statements) required to determine transaction amounts are not available until well into the following month, invoices cannot usually be generated until the middle of the month following actual sales unless an estimate using nominations is utilized. The most common provision states that the buyer will pay the seller within 10 days of receiving an invoice or the 25th day of the month, whichever is later.

Many contracts provide that the buyer pay the seller interest for payments made after the contractual date for payment. Late interest may take many forms, such as being based on the current prime rate or an agreed-upon fixed percentage.

Letter of Credit and Corporate Guaranty. When a buyer is deemed by a seller to be a credit risk, the seller may demand that buyer secure its purchases through a Letter of Credit issued by a reputable bank. While the Letter of Credit impairs the buyer's ability to use the amount of money tied up in the Letter of Credit, it does act as a guaranty that the seller will get paid for the gas it sells to the buyer.

Frequently the buyer or seller is simply a corporate shell lacking sufficient assets to pay damages for lack of contract performance. The contract may call for the shell company's parent or affiliate to guarantee performance.

Gas Committed. Historically, gas sales contracts provided for specified gas reserves of the seller to be committed to ensure delivery of the specified gas volumes. Such provisions are uncommon in today's gas sales contracts. Alternatively, the contract may provide that an agreed-upon deliverability volume be available. Sometimes the deliverability commitment is subject to a *best efforts* requirement, or volumes deliverable up to a specified maximum amount. While best efforts once meant the same as a nonfirm gas supply, it now has legal significance and carries with it a performance obligation.

Take or Pay. This provision refers to a certain volume of gas that must be taken by the buyer in a time period (e.g., a month or year). If the buyer does not take the agreed-upon volume of gas within the time frame, the buyer must pay as if it took the gas. After payment, there may be an opportunity for the buyer to take an equivalent gas quantity at a later date. In today's market, what had been the take-or-pay provision is now more normally called a *reservation charge*. Without this provision, a liquidated damages provision may apply to encourage contract performance.

Gathering Agreements

Gathering agreements are frequently used when wells are not connected directly by an interstate or intrastate pipeline, the gas from the field is aggregated by a third-party gatherer and eventually progresses into a pipeline system or a processing plant. The plant operator may also act as a gatherer. Another service that gatherers often provide is to centrally compress gas on their system, which alleviates the need for producers to set compressors at their wells in order to increase gas flow against prevailing pipeline pressures.

Transportation Agreements

Historically gas was shipped primarily by and for pipeline companies. As the new gas market evolved, gas users acquired their own supplies of gas through purchase arrangements and made their own arrangements for shipping gas on one or more pipeline systems.

There are two major types of transportation agreements—*firm* and *interruptible*. In a *firm transportation agreement* the pipeline guarantees a specified volume of available capacity for the shipper to use each month regardless of whether the service is used that month. Firm contracts are, in many ways, similar to renting a home. There is no refund for nonuse, just as there is no reduction in rent for nights spent away from home.

In return, the agreement requires the shipper to pay a specified monthly amount to reserve this available capacity called a *reservation charge*. It is calculated by multiplying the maximum daily quantity contained in the transportation agreement by the reservation charge per mmBtu for that service. This amount is paid whether or not the shipper moves its maximum daily quantity.

Firm service has historically been purchased from the pipeline. However, as a result of FERC Order 636, if a purchaser of firm service determines that the total firm capacity is not needed, the unneeded capacity may be released to another party in a secondary market by posting the *released firm capacity* on an electronic bulletin board. FERC regulations are in place that stipulate how the released capacity must be posted, bid upon, and awarded to ensure open access to all market services. The capacity that is released to the secondary market may be relinquished for less than what the original firm transporter has paid to the pipeline. The original firm transporter still has a binding contract with the pipeline, which must be paid whether or not a loss exists on the released capacity.

This secondary market has become an important price driver in the transportation services market.

Another transportation service option allows the shipper to exceed the maximum delivery volume of gas for a specified time, such as 24 hours, without incurring additional penalties. If a pipeline provides this service (*firm transportation with overrun capability*) and the shipper and pipeline have stipulated this term in the contract, there is usually a fee involved.

There are other charges based on the actual volumes of gas transported; these must conform to the range of prices dictated by a pipeline tariff. The *commodity charge* is the variable cost based on the actual volume of gas shipped and is paid in addition to the reservation charge. Besides the commodity charge, the pipeline collects other volumetric charges, such as surcharges to fund the Gas Research Institute[32] and other FERC surcharges. These are also specified in each pipeline's tariff. Generally, the amount of the charges increases with the distance gas is transported.

An *interruptible transportation contract* allows the transporter to interrupt or reduce the transportation service. It provides for the shipper to pay only the actual transportation charges on a volumetric basis (commodity charges) incurred in transporting the gas, when the pipeline has available pipeline transportation capacity after accommodating the transportation needs of shippers under firm transportation agreements. Any applicable Gas Research Institute surcharges and FERC surcharges are added to the commodity charge.

Rate and Term Provisions. Since interstate and many intrastate pipelines fall under some sort of regulatory nexus with the FERC, the terms and conditions of pipeline transportation and rates continue to be regulated through FERC approval of pipeline tariffs. Tariff and rate case negotiations between pipelines, their customers, and the FERC are complex and lengthy affairs.

Pipeline tariffs filed with the FERC appear in a common format. A map of the pipeline system is followed in the filing by a listing of rates to be charged for various pipeline services, which include not only transportation but also ancillary services, such as storage. Next, the tariff contains a usually lengthy description of the various services (called r*ate schedules*) that the pipeline is willing to perform, along with unique details of that service. The rate schedule section is followed by a section that lists

[32]The Gas Research Institute was founded in 1978 and supported by natural gas industry trade organizations and regulatory agencies to provide research, develop new technologies, and promote the natural gas industry.

the *general terms and conditions* (GTC) that are common to all of the pipeline's Rate Schedules. The GTC section will list such items as definitions, payment provisions, ways in which service may be interrupted or emergency conditions declared, and information about a pipeline electronic bulletin board. Finally, a standard form of agreement for each Rate Schedule appears in the tariff.

Pipelines subject to FERC regulation show maximum and minimum rates to be charged for service under each tariff Rate Schedule. While each of those rates is approved, each shipper and pipeline can negotiate rates that fall within the specified range for the service contemplated.

Likewise, the length or term of the transportation or storage contract is negotiated. While the term is something the prospective shipper provides in its notice, the pipeline advises whether or not the service requested is available for that term.

Fuel Charges. In addition to the above charges for transporting gas through a pipeline, there is usually a charge for fuel. The fuel charges are specified in the pipeline tariff, generally as a percentage of the shipper's gas. The pipeline would use this gas in pipeline operations, such as compressor fuel. Fuel charges and gas lost or consumed in its gathering and transportation are sometimes referred to as shrinkage.

Market Centers. The concept of *market centers***,** or *hubs***,** has been widely embraced by the gas industry. A market center describes a location where pipeline systems come together (envision a bicycle wheel where the spokes represent numerous pipeline systems transporting gas to and from a central hub where the pipelines interconnect) and specific services are provided to facilitate the trading of natural gas. Market centers can help promote competition, particularly by and between smaller customers; provide service reliability; and increase access to multiple pipelines.

Henry Hub in southern Louisiana is the best known example of a market center that provides both physical and transactional services for customers. It is also the point where gas is to be delivered under NYMEX gas futures contracts.

The hub administrator (or operator) has a unique knowledge of the activity and transactions taking place at the hub, enabling the administrator to offer a wide variety of services. Physical services that may be offered by the hub administrator include transportation, storage, compression, and processing. Transactional services may include title transfer, price swaps, and imbalance trading. Many of the services provided are identical to those offered by the pipelines, although with different names. Some of the more common market center services are described below.

1. **Transportation Services.** A hub may facilitate *wheeling*, i.e., the movement of gas from one pipeline system to another interconnecting pipeline by opening pipeline valves at the interconnects of the various pipelines in the hub or by a paper transfer that nets corresponding receipts and deliveries of the gas. A hub might also provide nomination assistance, track released firm capacity, and provide other agreed-upon services.
2. **Storage/Lending Services.** The market center operator may offer (1) traditional storage services over several months or (2) short-term storage generally within a given month. Short-term storage includes *parking* (i.e., having the hub store gas until needed, generally to meet the customer's peak demand during the month) and *banking* (i.e., having the hub store gas that was not taken by the customer, such as by an industrial customer on a slow weekend). Short-term borrowing of gas from the hub may also occur when a shipper sells more gas at the market center than the shipper delivers. Whether lending or storing gas, the hub operator charges a fee for the service rendered, and imbalances must be eventually cleared.
3. **Buy/Sell Transactions.** The hub may facilitate tracking custody and title of the gas among sellers, buyers, shippers, and transporters and provide appropriate accounting documentation for intra-hub transfers.

The operator of the market center may provide a service to match buyers and sellers of natural gas at the market center, invoicing the buyer and/or seller for this service.

It may also allow shippers to trade gas imbalances to minimize the shipper's exposure to imbalance charges in the market center. The market center administrator may provide a listing on the electronic bulletin board of shippers willing to trade imbalances or match shippers that request the hub's assistance in finding another shipper willing to trade, charging a fee for providing the match. The parties willing to trade then determine a settlement value between themselves.

Allocating Gas on the Pipeline. If a shipper's deliveries into a pipeline are less than or exceed the nominations, the transporting pipeline company must allocate the actual deliveries among the shipper's customers. If the shipper does not express to the pipeline how it wishes the difference between the actual deliveries and the nominations to be allocated to the shipper's customers, the pipeline will be forced to make the allocation. The pipeline will generally default to a *pro-rata allocation* based on the percentage nominated to each contract. Since nominated gas volumes and actual gas flow will never match, it is to the shipper's advantage to determine in advance where the gas should be allocated. By proper planning the shipper may avoid penalties and negative economic impacts caused by an arbitrary allocation of the gas. A schedule furnished to the pipeline, called a *predetermined allocation* (PDA), details how the shipper's actual delivered gas should be allocated to the customers. The shipper ranks the priority of each customer's contract on the PDA. The pipeline then completely delivers to the first contract on the ranked list before proceeding to the second name on the list.

Simple examples of both the PDA and pro-rata allocation methods are shown in Figure 12-2 using a nominated volume of 100,000 mmBtu scheduled for shipment and actual pipeline deliveries of 90,000 and 120,000 mmBtu.

Figure 12-2: Examples of Predetermined and Pro-Rata Allocation

Predetermined Allocation (PDA):

			Allocation of Actuals	
Shipper Contract	Nominated MmBtu	Rank	Under Delivery Scenario	Over Delivery Scenario
A	50,000	1	50,000	50,000
B	30,000	2	30,000	30,000
C	20,000	3	10,000	40,000
	100,000		90,000	120,000

Pro-rata Allocation:

			Allocation of Actuals	
Shipper Contract	Nominated MmBtu	%	Under Delivery Scenario	Over Delivery Scenario
A	50,000	50%	45,000	60,000
B	30,000	30	27,000	36,000
C	20,000	20	18,000	24,000
	100,000	100%	90,000	120,000

In the PDA example in Figure 12-2, the actual volume deliveries are ranked via instructions from the shipper. Contract C becomes the *swing* volume contract. If the shipper delivers only 80,000 mmBtu to the transporter, then the transporter delivers no gas under contract C.

The allocation methodology becomes more difficult when the shipper must attempt to allocate volumes to meet both daily and monthly required deliveries for numerous contracts. For example, if a shipper has contracted to deliver 10,000 mmBtu every day on Contract X, then the shipper may rank that customer as number one every day or give the producer a *keep whole* provision. The shipper also has Contract Y that requires a 15,000 mmBtu minimum daily delivery. Contract Z has a minimum monthly delivery. The shipper must allocate the gas so that Contract X receives the 10,000 mmBtu per day, Contract Y receives 15,000 mmBtu per day, and Contract Z receives the contracted minimum deliveries of gas by the end of the month. Therefore, ensuring that allocations are completed as indicated by the PDA is critical to avoid nonperformance penalties on the contracts or to avoid additional expenses in trading or buying additional gas to meet the contract volumes.

Imbalance and Scheduling Penalties. As has been discussed in Chapter Eleven, it is important that the gas is measured, dispatched, and allocated properly. With the increasing number of transportation transactions, the nomination and allocation of gas volumes have become increasingly more difficult. Failure to properly nominate and allocate volumes can lead to large gas imbalances over the pipeline's stated tolerances, which result in substantial penalties charged by the pipeline.

Producer imbalances can exist between the producers at a lease or gathering facility when a producer uses or sells more or less gas than its working interest share. Pipeline imbalances can result during the transporting of gas between the lease and the gatherer, the gatherer and transporter, or the transporter and the marketer. The term pipeline imbalance may refer to an imbalance between the purchaser and seller when the amount of gas delivered to the point of sale does not agree with the amount of gas the buyer makes payment on and receives.

Scheduling penalties occur when there is a variance between the gas nominated by the producer and the actual gas volume sent into the pipeline.

Imbalance penalties occur when the amount of gas received from the producer and delivered to the customer falls over or under the pipeline's designated tolerance.

Shippers are constantly faced with tough decisions in choosing the most economical, practical method of transporting the gas. Firm transportation, interruptible transportation, and firm transportation with overrun capability are considered in the transporting equation. Fuel usage and pipeline loss must be taken into account when determining the gas volumes delivered. Additionally, a shipper can pull gas out of storage or place gas in storage to balance pipeline receipts and deliveries.

Penalties may be offset by purchasing or selling gas with third parties to round out purchases or sales. Gas can also be exchanged with third parties to reduce or eliminate imbalances. One way to reduce the effects of imbalances between a shipper's nominated volumes and the actual gas shipped is to take advantage of operational balancing and pooling agreements with other parties to minimize the opportunity for penalties by combining balances. *Operational balancing agreements* may be used to attribute the gas imbalance differences to the producer and customers, leaving the shipper out of the picture. *Pooling agreements* may allow the producer to net gas volumes at several different receipt and delivery points, stating how the imbalance will be resolved at a later date.

Pipeline accountants have the responsibility to flow through any penalties to the producers, sales customers, or shippers, depending on who caused the penalties. Daily and monthly penalties may be incurred for imbalances over or under the tolerances. Accurate records are critical to the process of reconciling volume discrepancies, as pinpointing the cause of pipeline penalties can be very burdensome and time-consuming.

Management Services Contracts

Management services contracts are those where one party has contracted to another to transport, purchase, or sell gas on its behalf. In exchange, the company providing the management services will receive payment of a specified amount per mmBtu of gas purchased or sold. Frequently, the amount per mmBtu is specified as a percentage of the price or savings.

NATURAL GAS LIQUIDS MARKETING

U.S. NGL MARKETING

Summarized below are the general factors in marketing NGL at natural gas plants in the United States.

Physical Quality. NGL consists of distinct types of hydrocarbons with different markets and competitive products. Their relative U.S. production in late 1999 is summarized below:

Hydrocarbon	Oct. '99 Production[33] (mbbls/d)	%	Price[34] (¢/gal)
Ethane (C2)	729	38%	35.12
Propane (C3)	545	28	45.37
Normal butane (nC4)	163	8	51.12
Isobutane (iC4)	188	10	51.37
Natural gasolines or pentanes plus (C5+)	312	16	54.00
Total NGL	1,937	100%	

In 1998 16.6 tcf of gas were processed in the U.S., producing 668 million barrels and losing an estimated 938 bcf of gas (5.7 percent of wet gas) in the extraction of the NGL.[35] That equates to extracting on average 1.7 gallons of NGL per mcf of processed wet gas. It is also 30 gallons of NGL per mcf lost in the extraction. If NGL sold on average for 45 cents per gallon, the 30 gallons of recovered NGL provides $13.50 worth of NGL per consumed mcf. The value of extracted NGL substantially exceeds the value of the lost gas (in most market conditions).

Potential Customers. A major NGL end-user market in the U.S. is the petrochemical industry concentrated on the Gulf Coast. The petrochemical industry's olefin plants use ethane and propane as major feedstocks for making basic petrochemicals, such as ethylene and propylene. Alternative major feedstocks for many plants are naphtha and gas oil, which are products from crude oil refining. Variations in the price of crude oil can affect the cost of naphtha and gas oil and indirectly the price of ethane and propane as petrochemical plants seek the best, most economical, available feedstocks.

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[33] Source: *Energy Information Administration* at www.eia.doe.gov

[34] October 1999 average spot prices at Mont Belview, Texas located just east of Houston, close to major Gulf Coast Petrochemical facilities. These prices are thus greater than the average prices of NGL sold at U.S. gas plants. Source: *Oil and Gas Journal* www. ogjoline.com

[35] Source: *Energy Information Administration* at www.eia.doc.gov

Another major U.S. market is rural home heating and cooking and agricultural use of *liquefied petroleum gas* (LPG or *bottled gas*), consisting of propane or primarily propane.

A third major market is crude oil refining that can use butanes and natural gasolines as blendstocks for making refined products, such as gasoline.

For independent gas producers, it is generally impractical for the producer to sell to these NGL end-user markets, whereas many producers now sell dry natural gas to end users. Major oil and gas companies with gas production facilities, refineries, and petrochemical plants may market the NGL to downstream intercompany facilities. The typical independent producer's potential customer is generally either (1) the gas plant owner who simply buys the wet gas or (2) the gas plant NGL customer in transactions arranged by the gas plant owner.

Location. The extraction of NGL in downstream gas processing plants serving several producers contributes to the practice of many gas producers marketing to or through the gas plant owner. Location, in a broad geographical sense, of NGL production compared with primary markets can also affect the pricing and marketing of NGL components.

Supply Versus Demand. U.S. NGL supply is dependent largely on the production of U.S. natural gas, which has grown in recent years but is still below productive capacity. NGL imports have declined over the past several years from 88 million barrels in 1984 to an estimated 64 million barrels in 1999. The U.S. has a strong demand for NGL aided by a system of NGL pipelines to move NGL to major markets. However, just as crude oil may be sold at the lease into trucks, NGL may be temporarily stored at the processing plant to be sold and delivered into special trucks largely to meet regional demands, as opposed to being delivered into an NGL pipeline to major petrochemical plants.

DESCRIPTION OF MARKETING OPERATION

As discussed in Chapter Eleven, in addition to separating the dry gas to meet downstream pipeline specifications and make it merchantable, another reason for processing natural gas is to extract the NGL stream. The sale of the products after fractionation of the NGL stream commands a high enough price to make the processing profitable and to provide valuable products to the end users. A sophisticated marketing system with primary and secondary market centers for the transportation, purification, storage, and marketing of NGL has developed in recent years to meet the many NGL market requirements.

As stated in Chapter Eleven, natural gas is generally processed in plants in the field. The wet stream may then be sent through the pipeline to a fractionation facility in close proximity to the processing plant, depending on location and economic factors, or to a fractionation facility located closer to the market, such as a major pipeline connection or a market center.

The NGL seller may be a plant owner or plant operator who has purchased a natural gas stream from a producer through a gas purchase contract and now holds title to the NGL (and the gas). The producer of the natural gas stream should receive a price for the wet gas based on the value of all the products in the stream: the residue gas, any by-products (such as sulphur), and the NGL. The plant owner negotiates a contract to sell the NGL to a marketer, market center, or a large industrial user or refiner.

If the lease operator or producer has a gas processing agreement, the producer would retain title to the NGL and would have the same options to sell NGL to a marketer, market center, or large end user.

Typical contracts in the field will provide the producer an allocation of liquid revenues or in-kind products attributable to a well's production. Standard preprinted industry forms allow delivery dates, quantities, location, delivery method, special product specifications, and price to be inserted when negotiated. The industry standards and specifications for measurement are usually referenced in the measurement sections of the contract. There are stated penalties for quantities of product delivered from the plant that fail to meet the purchaser's specifications. It is common for there to be a small provision for loss of product. Exchanges of one product for another with a specified price differential, any other price adjustments, or monthly fees for storage services should be clearly stated in the contract. Most contracts provide for an audit of the settlement price.

NGL PRICING

Pricing is determined by industry postings provided at the main market centers (Conway, Kansas, and Mont Belvieu, Texas) for defined pure products with net-back provisions for transactions at the processing plant. The postings specify storage or pipeline facilities within these locations. Oil Price Information Service (OPIS), a division of United

Communications Group, provides PetroScan (an on-line petroleum price database of NGL, gas, and petroleum product prices). PetroScan or the weekly *Oil Price Information Service* newsletter often serves as a pricing reference in contracts for settlement purposes. The OPIS definitions and specifications are available from the publisher upon request and should be documented in any payment calculation or audit procedure.

Marketing fees are deducted as a percentage of the posted prices or actual resale prices or as a fixed number of cents or even fractions of a cent per gallon sold. Pipeline and/or truck transportation and fractionation charges (sometimes called *T&F charges*) are established with the facilities or equipment owners in the form of fixed amounts per gallon. The market price may be severely discounted in the case of products that fail to meet the purchaser's specifications. In some cases, the seller may incur a cost for proper disposal of contaminated products.

Chapter Thirteen

ACCOUNTING FOR OIL, GAS, AND NGL SALES

INTRODUCTION

Chapter Eleven explained how oil and gas volumes are measured. Chapter Twelve addressed how oil and gas are sold. With a basic knowledge of volume calculations, contract terms, and pricing, a revenue accountant may now value the products in accordance with the sales contract (and any applicable government regulations) and record the appropriate revenue accounting entries.

THE COMPLEXITY OF REVENUE ACCOUNTING

Authoritative statements on successful efforts and full cost accounting methods say little on accounting for revenues. However, proper revenue accounting is complex due to a number of factors such as multiple owners, multiple forms of distribution from purchaser to each owner, changes in purchasers, varying production tax rates by property, varying royalty rates by property, purchaser/operator/pipeline accounting errors, gas imbalances (Chapter Fourteen), fluctuating prices, and changes in ownership interests (Chapters Twenty-One to Twenty-Three).

The following example illustrates the complexity of having multiple owners and multiple forms of distribution. Assume Our Oil Company (OOC) has a 30 percent net revenue interest in a property burdened with a 25 percent royalty. Production taxes are 5 percent. One month, $100,000 of petroleum is sold from the lease. OOC's revenues are $30,000, and its production tax expenses are $1,500 for each lease. The purchaser's practice of distributing proceeds may be any one of the following:

1. Pay OOC $28,500, net of the royalty and the production taxes (common for sales of U.S. oil production, whereby the purchaser pays the royalty owner and local government directly);
2. Pay OOC the entire $100,000 and let OOC distribute the revenues, paying the royalties and severance taxes (common for sales of U.S. natural gas production);

3. Pay OOC $95,000 (withholding the production taxes for payment directly to the local government) and let OOC distribute the payment to the royalty holder and working interest owners; or
4. Pay OOC some other amount between $95,000 and $28,000, e.g., $57,000 for OOC and a group of working interest owners with a combined 30 percent NRI who affiliate with OOC for revenue distributions.

Despite all the complexities noted above, an E&P company must have an accounting system that accurately and efficiently records oil and gas proceeds and properly redistributes proceeds rightfully due others. A key element in such an accounting system is the *division of interest file* (also called a *DOI file* or *D of I file*). This master file contains the revenue sharing percentages for each unique distribution based on the lease identity, the month of sale, and the petroleum purchaser. The source for sharing percentages is a *division order* as explained below.

SOME GENERAL ISSUES

Before addressing revenue accounting by product type (oil, gas, or NGL), it is helpful to explain five general matters:

- Division orders,
- Distribution accounting,
- Royalty reporting,
- Revenue accounting organization, and
- Revenue accounting centers.

Production and *ad valorem* taxes, the expenses commonly deducted from revenue distributions, are explained in a separate section.

DIVISION ORDERS

As discussed in Chapter Seven, contractual agreements between the parties determine ownership interests, and usually no two contracts are exactly the same. These agreements can create many different owners in a single mineral property, requiring distribution of sales proceeds to each. Oil purchasers generally will send separate checks to each owner. Many gas purchasers prefer to pay all net revenues to the operator. As a result, the operator must distribute gas revenues to the various owners of the working interests, royalty interests, and any overriding royalty interests, net profit interests, and production payments.[36] If the working interest owners do not sell their gas collectively, each working interest owner may take its gas in kind, sell it to the party of its choice, and receive a net revenue check from its gas purchaser. So the parties must reach agreement as to who distributes gas revenues to whom.

A *division of interest order* (*division order*, *DOI*, or *D of I*) is the agreement between the purchaser of production and all the owners indicating how the purchaser should distribute the production proceeds. If the operator or other working interest owner is receiving revenue on behalf of itself and others, it should have a division order for its distributions to the other parties.

The division order includes the legal description of the property, the owners of interests in the property, the interest owned by each, and sometimes the terms of purchase (including provisions dealing with passage of title to the products, price, measurement, production taxes, and related items).[37] Each owner, by signing the division order, guarantees its ownership to be as stated, authorizes the purchaser to receive the product(s) from the property and make payment to the owners in proportion to their respective interests, and agrees to all other provisions of the division order.

Copies of division orders are retained in the files of the operator and the purchaser. A division order constitutes the accounting department's authorization to make payment to the various owners of interest, credit revenue to the income accounts, or credit the revenues from certain interests to suspense. New division orders or changes in division orders are reported on a *notice of division order changes* which contains the lease identification, the names and addresses of all interest owners, the fractional interest belonging to each, the fractional interest or interests to be held in suspense, and for a transfer of interest, the fractional interests of the grantor and grantee before and after the transfer or change in interests held in suspense. A division order is illustrated in Figure 13-1.

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[36]Overriding royalty, net profits, and production payment interests are discussed further in Chapters Twenty-One through Twenty-Three.

[37]Each owner's interest is based on a title opinion rendered by the legal department after examination of abstracts of title supplied by the operator of the property.

Figure 13-1: Oil and Gas Division Order[38]

NADOA Model Form Division Order (Adopted 9/95)
DIVISION ORDER

To:

Date: February 5, 2000

Property Number: 094-730-8820-1800
Property Name: Bell Heirs "A"
Operator: Big Oil USA, Inc.
County and State: Montague County, TX
Property Description: [Legal Description]

Effective Date: Commencing at 7:00 a.m. Date of First Purchase

Production: __X__Oil __X__Gas _____Other:

Owner Name and Address:	Owner Number:	Decimal Interests:	Type of Interest:
Big Oil USA, Inc.	197954	.50000000	WI
KT Oil, Inc.	287643	.21375000	WI
Amber Bell	634322	.06250000	RI
Frederick Bell	725873	.03125000	RI
Micah Bell	725874	.03125000	RI
Walter Johnson	697389	.00672550	ORRI
Phyllis Johnson	697390	.00672550	ORRI
Raymond Skinner	487653	.00345490	ORRI
Melvin Kirkland	567839	.00962500	ORRI
Lois Kirkland	567895	.00962500	ORRI

The undersigned certifies the ownership of their decimal interest in production or proceeds as described above payable by Big Oil USA, Inc. (Payor).
(Company Name)

Payor shall be notified, in writing, of any change in ownership, decimal interest, or payment address. All such changes shall be effective the first day of the month following receipt of such notice.

Payor is authorized to withhold payment pending resolution of a title dispute or adverse claim asserted regarding the interest in production claimed herein by the undersigned. The undersigned agrees to indemnify and reimburse Payor any amount attributable to an interest to which the undersigned is not entitled.

[38] This division order has been developed by the National Association of Division Order Analysts (NADOA) and is the primary form used in the industry. The NADOA also publishes the *National Association of Division Order Analysts Journal* containing guidelines in writing division orders.

Figure 13-1: Oil and Gas Division Order, continued

Payor may accrue proceeds until the total amount equals $25.00, or pay on December 31, whichever occurs first, or as required by applicable state statute.

This Division Order does not amend any lease or operating agreement between the undersigned and the lessee or operator or any other contracts for the purchase of oil or gas.

In addition to the terms and conditions of this Division Order, the undersigned and Payor may have certain statutory rights under the laws of the state in which the property is located.

Special Clauses:

Owner(s) Signature(s):
Owner(s) Tax I.D. Number(s):
Owner Daytime Telephone #:
Owner FAX Telephone #:

Federal Law requires you to furnish your Social Security or Taypayer Identification Number. Failure to comply will result in 31% tax withholding and will not be refundable by Payor.

Division orders may have special clauses in the body of the division order or as attachments that contain the legal language and agreements between the interest owner and the operator or the payor. These may include definitions of terms, identification of quantity measurement methods, quantity determination, inclusions and exclusions in payment proceeds calculations, circumstances that dictate when proceed amounts may be withheld, dates of payment, methods of payment, confirmation of valid title, and any other special arrangements.

DISTRIBUTION ACCOUNTING

An E&P company's revenues are its share of revenues net of royalties and overriding royalties and excluding revenue interests owned by others. For example, if a well's gross revenue from gas production is $100,000 before a ten percent state production tax and the E&P company's net revenue interest is 30 percent, then the E&P company's revenues are $30,000 and its share of production tax expense is $3,000. If the E&P company receives the full $90,000 of revenue proceeds (net of production taxes withheld and paid to the state), it keeps $27,000 and must distribute

$63,000 to other interest owners, including the state tax agency. In such a case, it is common to record the full receivable and full distribution payable while recording net revenue and net production tax expense as follows:

120	Accounts Receivable—Oil & Gas Sales	90,000	
710.011	Production Taxes	3,000	
	302 Revenue Distributions Payable		63,000
	602 Gas Revenue		30,000

To record gas revenue for well [name] for [month, year].

Exceptions to this rule are accounting for minimum royalties recorded as a production expense (discussed at the end of this chapter) and recognizing revenues for gas quantities taken and sold that give rise to gas imbalances (discussed in Chapter Fourteen). Occasionally, in foreign lands the E&P company's local subsidiary will record royalties as an expense and revenues gross of royalties pursuant to a production agreement with the host country's government. For the E&P company's consolidated financial statements, the royalty expense would be eliminated and the production revenues would be net of the expense.

Revenues Held in Suspense

Revenues may be held in suspense and not distributed for various reasons:

- Awaiting an executed division order,
- Awaiting an executed change in ownership of a working interest or royalty interest,
- Awaiting proof of title or title opinion,
- Awaiting resolution of dispute as to ownership interest,
- The signature of an owner of interest cannot be obtained on the division order or transfer order,
- The particular distribution is minimal, or
- Prior distributions to a particular owner have not been cashed, indicating that the owner is lost or has abandoned the property.

When awaiting an executed division order, all revenues may be held in suspense. If only a particular interest's owner is in doubt, only that portion of revenues would be held in suspense.

The division order typically provides that if a particular distribution is minimal, below a stated amount (e.g., $25 in Figure 13-1), then the amount need not be distributed until the cumulative distribution payable exceeds the stated amount. However, it is customary to distribute all amounts owed at the end of the year, even if they are less than the minimum amount. State or local regulation or the lease agreement may determine the minimal amount for the related royalty payment.

When owners are not known or cannot be located, the amounts due are customarily paid into an escrow account. Whether held in escrow or not, unclaimed distributions fall under state unclaimed property (*escheat*) laws and regulations. Various outside companies may be engaged to find the owners, generally charging fees to the owners found. However, after several years (generally five or seven), the unclaimed revenues held in suspense must be distributed to the appropriate state pursuant to state *escheat* laws.

ROYALTY REPORTING

Depending on which party has responsibility, either the operator or the purchaser must make periodic (usually monthly) payments and reports to the royalty owner. The report, which usually is in the form of a settlement statement or check stub (also called a revenue *remittance advice*), should identify the lease(s) involved, the month covered, the number of barrels of oil or condensate or mcf of gas sold, the sales price, the royalty owner's percentage of production ownership, the state production or severance tax withheld, and the net amount paid the royalty owner.

The United States Department of Interior's Minerals Management Service (MMS) has the responsibility to collect and account for the royalty interests that are owned by the federal government in onshore and offshore properties in the United States. The MMS requires that detailed, specific reports on production, sales, and other dispositions of products be filed on monthly and annual bases along with a check for the royalty. From these reports the MMS compiles information to determine if it is receiving all royalties due. MMS regulations change very frequently and are beyond the scope of this book. The MMS distributes manuals to operators explaining proper filing of its required forms. The revenue accountant should be properly informed in this area, as heavy penalties are incurred for not reporting and paying the royalty by the deadline dates.

Contracts or state regulations sometimes call for other data to be shown or for copies of supporting documents such as pipeline run tickets to be enclosed.

REVENUE ACCOUNTING ORGANIZATION

Because of differences in individual oil company operations, size, and structure, there is no standard organizational pattern that dictates how the revenue accounting function should be accomplished.

Companies with only a few producing properties may employ one accountant to perform all functions of a revenue department (or the entire accounting department). As in any small company with a job position that involves financial transactions, more creative solutions in terms of accountability and segregation of duties are required to achieve a system of internal controls. Generally the small company may have less sophisticated information and accounting systems, which may have an impact on the type of entries in the revenue recording process.

Larger companies may incorporate numerous specialized positions (such as a gas accountant or a production tax accountant) or units (production accounting, gas control, or royalty owner accounting) to achieve the revenue accounting function. Larger companies are more likely to have sophisticated information and accounting systems.

REVENUE ACCOUNTING CENTERS

One of the primary responsibilities of the revenue accountant is recording revenue to the correct property, measurement point, tank, or well. Therefore, one of the first issues is to identify revenue accounting centers to be used to accumulate and group recorded revenue. Generally the revenue accounting center is the well but may be a field, lease, prospect, or other defined aggregation of activity for grouping volume, cost, and revenue information by use of a distinct accounting center reference, such as a combined alpha and numeric code. The centers are needed to set up receivables, record production, make proper distribution of proceeds to the working interest and royalty interest owners, record accruals, and calculate taxes.

In many E&P companies, the revenue accounting center is not determined solely by the accounting department but on a company-wide basis, because the centers may be used as areas of responsibility in the production, land, and marketing activities, as well as in the accounting department. Hence, the centers are commonly referred to as accounting cost centers even within revenue accounting functions. The amortization cost center for full cost accounting is countrywide; for successful efforts, it is the lease or reasonable aggregation of leases. However, the accounting cost center often needs to be by well for purposes of management oversight or by lease for income tax reporting.[39]

PRODUCTION TAXES AND *AD VALOREM* TAXES

PRODUCTION TAXES

Most states levy one or more types of tax on oil and gas produced in the state. These taxes are computed on the basis of volumes and/or values of oil, condensate, gas, NGL, and sulfur produced and sold or consumed. These taxes are called *production* or *severance taxes.* The taxes are usually levied at the time and place that minerals are severed from the producing reservoir.

Another tax imposed by some states is a *conservation tax*, used to provide funds for the state governments' energy conservation, oversight, and research programs.

Many Indian tribes assess a production tax. These taxes are usually credited against the amounts otherwise due the state in which the well is located. Each tribe and state varies as to the assessment method and rates.

The revenue accountant must be familiar with the current tax laws of the states where producing properties are located as governmental regulations mandating different types of taxes and rates are subject to constant change. The Council of Petroleum Accountants Societies (COPAS) *Oil and Gas Severance Tax Guide*, the Commerce Clearing House, Inc.'s *State Tax Reporter*, and other sources provide periodic updated information on current taxes related to oil, gas, and NGL production and sales. The Society of Petroleum Evaluation Engineers website at www.spee.org provides such information by state to assist petroleum engineers in economic modeling and reserve estimation.

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[39]By well is necessary when joint venture owners elect to go nonconsent on a well whereby revenue interests and working interests vary by well, as discussed further in Chapter Twenty-Three.

Calculation of Production Taxes

As stated above, the basis for determining the amount of tax due is the value or the volume of the oil or gas that is produced and sold during a predetermined period of time. The accountant should be aware of whether the taxing entity bases the tax rates on the production produced from the property or the production sold. The accountant should also be aware of whether the purchaser or the producer is responsible for the payment and remittance of the tax as determined by state regulations or contractual agreements. State laws specify the tax rate and the basis of assessment of the particular product. One of the most common tax methods specifies a fixed percentage to be applied to the total gross value of the product sold in a month. Some states base the tax on the volumes of petroleum sold. A few states combine the two bases of value and volume in assessing taxes due. In other words, either volume or value is used, whichever generates greater revenue to the state. Several special provisions currently being used by taxing entities are listed below:

- The gross value of oil may be reduced by a designated cents per barrel before applying the tax rate to reflect the barge, pipeline, and/or trucking charges necessary to transport oil produced and sold.
- The value of natural gas can be reduced by documented *marketing deductions* (typically costs incurred beyond the separator, such as dehydration that may be required to make the gas saleable to a purchaser) with approval from the state.
- Different rates can be levied based on the producing property's location within counties, school districts, or municipalities; in some states, rates vary with the date that the lease commences commercial production.
- Some other states have different rates for a special classification of wells, such as wells incapable of producing more than 25 barrels of oil per day.
- Rates may differ based on the price of crude, such as one rate for crude that sells for less than $12 a barrel and a different rate for crude that sells for $12 a barrel or more.

Payment of Production Taxes

The oil or gas purchaser may deduct the taxes from the sales proceeds and pay the producer the net amount. The purchaser then remits the tax amount due, along with a tax form or schedule, to the appropriate state collection agency. Alternatively, the purchaser may pay the producer the gross value of production, and the producer remits the taxes to the state collection agency.

Some activities and ownership interests are exempt from taxes. For example, injection gas, vented or flared gas, and gas-lift gas are exempt in some states. Interests owned by the federal government, state government, or Indian tribes are exempt from taxes in most states. Sometimes contractual agreements between the parties result in tax-free interests. In this situation, the other owners must bear the non-tax-paying owner's share. In general, production taxes are borne proportionately by all interest owners, including the royalty interest owner.

States typically require monthly payment and reporting. Usually both the producer and purchaser must file a monthly tax report. The reports are generally due one to two months following production. The reports submitted by the purchaser and producer are compared by the states to determine that the taxes due were reported and paid correctly. Production reports generated by the operations department and filed with the state may also be compared with the tax reports. Many states also require quarterly and annual reporting.

The detail included on the tax reports varies from state to state, but usually the production volume, production value, and tax for each production unit or lease must be shown with a summary for each county or parish.

Penalties

The tax-assessing agency may impose penalties and interest for failure to file reports timely and failure to timely or fully pay taxes due. In many states, the penalties may be waived if the delinquency is not attributable to taxpayer negligence. In some states, failure to file tax reports is classified as a misdemeanor, with a fine and/or jail term as a possible penalty. Some penalties for late filing are a specific dollar amount regardless of production volume or value, while other penalties are stated as a specific percentage applied to the late report's production volume or value.

Refunds of Production and Other State Taxes

For various reasons an overpayment of state taxes can occur. Refund procedures vary from state to state. Some states require filing an official claim for the refund, along with supporting evidence. Other states require that amended tax reports be filed. Still other states allow a reduction in the amount of taxes due in the current month for all refund requests and then notify the taxpayer if the claim is disallowed.

AD VALOREM TAXES

Ad valorem (Latin for according to the value) taxes and property taxes are generally levied by the county, school district, and other local taxing entities where the production occurs. *Ad valorem* taxes are generally based on either (1) the level of production occurring in the previous calendar year or (2) on the estimated fair market value of well equipment or economic interest in the property. Tax rates may vary widely among the local taxing entities, and a county or parish may encompass many different taxing entities.

While similar to production taxes in terms of calculation (e.g., applying a statutory rate to the gross value of production or to an assessed value), *ad valorem* taxes are noticeably separate and thus provide the revenue and joint interest accountant with some unique challenges. For example, a state such as Colorado or Wyoming, which impose an *ad valorem* tax on both the gross value of production and on equipment, requires special handling.

For paying *ad valorem* tax based on gross production value, the distributor of revenues may withhold and escrow estimated taxes from distributions to all interests owners (with the exception of any tax-exempt owners). However, the working interest owners pay all *ad valorem* taxes assessed on equipment value.

As a general rule, the operator of the property is responsible for reporting and paying *ad valorem* taxes even though the purchaser often withholds and remits production and severance taxes. Another difference between *ad valorem* taxes and production taxes is the frequency of reporting. Production taxes are usually paid and reported on a monthly basis, while *ad valorem* taxes are paid annually.

Many operators withhold estimated *ad valorem* taxes from monthly revenue distributions to reduce the risk of uncollectible taxes from owners should the well unexpectedly cease production or a joint venture owner become insolvent.

Because of the high degree of specialization and varying regulations imposed by states and local taxing jurisdictions, *ad valorem* taxes may require a significant amount of attention. Failure to emphasize their importance can expose an E&P company to significant losses resulting from uncollectible taxes from nonoperators or from excessively high property tax appraisals that go unchallenged by the E&P company.

ACCOUNTING FOR OIL SALES

INFORMATION FLOW TO THE ACCOUNTING DEPARTMENT

The revenue accountant is responsible for ensuring that correct revenue entries are recorded and that correct revenue disbursements are made to owners. This process includes comparison of the settlement statement or revenue remittance advice information from the purchaser to internal company records of volumes sold, contract prices, tax rates, and net revenue interests. Therefore, the revenue accountant is required to interact closely with the production, land, and marketing departments to access the appropriate information to ensure that proper accounting entries are recorded for each property. The process of information verification will vary from company to company, with some verification often being delegated to other departments.

Most smaller and intermediate-sized companies record revenue and the volumes associated with the revenue directly from the check receipt and the attached documentation from the purchaser. Procedures need to be established to provide a verification of the volumes measured at the lease or central facility to the volumes indicated and paid for by the purchaser. Larger companies or companies with more sophisticated computer systems may have the capabilities that allow the production department to enter actual sales volumes directly into the system that is accessed by the revenue accountant. Methods for volume verification include, but are not limited to, the following:

1. In a very small company, a production clerk/accountant may receive the pipeline run tickets, internally calculate or outsource volume calculations, and verify that the statement of pipeline runs and the volume on the purchaser's check agree with the pipeline run tickets.
2. Production clerk(s), or other operations personnel or the production accounting department maintain the meter tickets. The production calculated from the tickets is provided in a report (sometimes called the production ledger) to the revenue department, which has responsibility for verifying that the volumes agree.

3. Production clerk(s) maintain the meter tickets, and the revenue department generates a report (such as a lease operating statement illustrated in Figure 15-1 in Chapter Fifteen) that includes sales volumes received from the purchaser. The production department has responsibility for verifying that the correct volumes were received.
4. Production clerk(s) maintain the meter tickets and enter the volumetric amount, gravity, and other pertinent information into the company's information system. The revenue accounting department accesses this information and verifies that the volumes paid for by the purchaser agree with the volumes entered by the production department during the monthly closing process.

The company also needs a process to verify that the amounts and terms negotiated on sales contracts are followed when revenue is received. Generally sales contracts will be maintained in the marketing department. A set of procedures needs to be established to provide the revenue accounting department, or other assigned department, a method of verifying that correct contract terms and prices are being used. This is more easily implemented with an integrated computer system that allows direct on-line entry of contract prices by the marketing department and subsequent access by the revenue accounting department to make monthly closing entries.

As stated above, the revenue accountant is responsible for ensuring that revenues are properly distributed. Division orders and royalty agreements generally reside in the land department. The land department is responsible for providing a record to the accountant (or the information to prepare the record) called a *revenue deck* containing the correct group of interest owners and their ownership percentages in the property.[40] This ownership record is assigned a unique code that, when referenced with the property's assigned, identifying accounting center number, directs the accountant or the computer system to set up payables to the correct owners at their

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[40]The revenue deck includes all owners: working interest, royalty, overriding royalty, state, federal and Indian royalty owners. This deck should sum to 100 percent (with the exception of some very unique cases). Most revenue accounting systems then will set up a payable for each owner in the deck. Payables are summed by owner for all properties. On a specified date, the system prints and distributes a single revenue check to each owner for the accumulated royalty payable for a given production month.

current ownership percentages in the property. If an interest owner assigns or sells its interest or part of its interest, a new revenue deck reflecting the new ownership would be set up and assigned a new unique code.

For example, assume OOC has an 80 percent working interest and a 68 percent net revenue interest in a well that started production on August 11, 2000. OOC's accountant sets up a revenue deck called R1 that contains the OOC 68 percent net revenue interest and a 32 percent interest to other owners. OOC sells half of its interests to HES Oil Co. effective October 1, 2000. OOC's accountant sets up a second revenue deck called R2 reflecting the new net revenue interests: OOC, 34 percent; HES Oil Co., 34 percent; and other interest owners, 32 percent. The first revenue deck is closed. Any sales occurring after September 30, 2000, are distributed using the second revenue deck.

EFFECTIVE DATE OF OWNERSHIP CHANGE

To facilitate accounting, agreements that call for ownership changes upon payout (explained in Chapter Twenty-Three) should specify the effective date. The governing agreement may provide for the ownership change to be effective (1) the first day immediately after the month when payout actually occurs or (2) on the day after payout is calculated to occur (see App. 9-20). The second approach requires a special allocation of the joint venture's revenues and costs for the month as noted in COPAS Bulletin No. 9.

RECORDING OIL SALES

Cash Receipts Approach

Some companies record revenues directly from information accompanying the purchaser's check. The actual revenue check is generally received directly by the company's lockbox at its bank or by a department in the company's finance office that is responsible for depositing the cash and sending a copy of the check and any documentation received to the revenue accountant. Cash is debited and an accounts receivable for oil and gas sales is credited for the amount of cash received.

The statement or check receipt attached to the actual check, identifying the production volume purchased, related taxes, and revenue received, is called a *remittance advice* or *settlement statement*. An accompanying statement of pipeline runs should also be provided by the purchaser or pipeline.

To illustrate, suppose that Our Oil Company receives a statement of oil runs from a lease showing the data below. The purchaser withholds taxes and pays each interest owner the net amount due.

OOC's share of oil sold is 700 barrels	
Oil revenue at $20/bbl	$14,000
Less 5% state severance tax	(700)
Net proceeds received	$13,300

The treasury department would record an entry debiting cash and crediting accounts receivable for $13,300. The revenue accountant would record the following entry:

120	Accounts Rec.—Oil and Gas Sales	13,300	
710.011	LOE—Production Taxes	700	
	601 Crude Oil Revenue		14,000

To record revenue on receipt of settlement statement.

These entries under the cash receipts approach reflect cash basis accounting (even though GAAP calls for accrual basis) and provide little control over sales or production. The preceding subsection explained how the revenue accountant, working with the production department, could verify the data on the purchaser's remittance advice.

Since the revenue check generally comes one or two months after the sale, the E&P company accrues on the monthly financial statements estimated revenue earned but not yet received. The basic entry debits accrued receivables and credits oil (or gas) revenue. The accrual estimation process will vary by company. The accrual may be based on simply the previous one or two month's total revenues or a more sophisticated analysis of actual production and estimated or actual prices. The production department should be able to supply current volume information on properties operated by the company. On nonoperated properties, the accountant may need to make an estimate of oil volumes based on past production history of the property.

The accrual entry should include the applicable production taxes and the net amount receivable using the same accounts as in the above cash basis entry.

This adjusting entry would then normally be reversed at the beginning of the next month so that the E&P company can continue to record revenue and taxes in the usual manner at the time settlement in cash is made.

If the accrual and reversal are prepared only on an annual basis, the reversal in the new period may cause material distortions in interim statements.

Accounts Receivable Approach

Under the accounts receivable approach, the E&P company records each cost center's revenue based on internal records of quantities sold, prices, and production tax rates or internal invoices. Rather than debiting accrued receivables, the revenue accountant debits accounts receivable and records the receivable to an accounts receivable subledger for the particular purchaser, as though the purchaser had been invoiced. When the purchaser's check is received, a treasury accountant records an entry to debit cash and credit accounts receivable for the particular purchaser. Any unusual balance in the accounts receivable subledger is investigated, and any recording errors or purchaser errors are corrected. For example, assume that OOC's records shows more oil sold and at a higher price than the oil purchaser's remittance advice, as illustrated in the following schedule:

	Per OOC	Per Purchaser
OOC's share of oil sold	705 bbls	700 bbls
Oil price	$20.20/bbl	$20.00/bbl
Oil revenue	$14,241	$14,000
Less 5% state severance tax	(712)	(700)
Net receivable	$ 13,529	$ 13,300

When revenues and production taxes are recorded, accounts receivable would be debited for $13,529. When the oil purchaser's $13,300 check is deposited, accounts receivable would be credited for $13,300, leaving a $229 accounts receivable balance to be investigated.

Note that neither the cash receipts approach nor the accounts receivable approach as illustrated above recognizes crude oil inventory in lease tanks. As discussed later in this chapter, it is common for E&P companies to not recognize such oil inventory in their financial statements.

A record of the earnings for each lease or well is needed to complete the federal income tax return, to prepare management reports, and to file reports with regulatory agencies. Thus, revenues are commonly recorded in an operating revenue subledger, with a separate record for each revenue accounting center (generally a well). The information shown for each accounting center would include at least the following for oil sales:

- Property identification,
- Interest owned,
- Oil runs (gross barrels, net barrels),
- Net revenue interest share of gross value included in revenue,
- Total revenue for the month, and
- Cumulative revenue for the year.

Gas sales might be shown in the same subledger or a separate gas revenue subledger.

Integrated Information and Accounting Systems

In companies using more sophisticated information and accounting systems, the production clerk or operations personnel, production accounting, gas control, or other designated department enters the oil volumes and related volume measurement factors by accounting center directly into the on-line system.

The marketing department, having responsibility for negotiations and valid sales contracts, enters the agreement on-line by property or measurement point.

The DOI owners and their interests are entered into the system by the use of date-sensitive codes that indicate the current revenue deck containing the ownership interests to be used by the system to record and make payments to owners.

The revenue accountant verifies that settlement statement information agrees with on-line numbers from the members of other departments. Daily or monthly pipeline information is entered into the system to provide monthly accruals. Production and other state tax information is entered and verified periodically by a tax accounting group.

When the revenue accountants are confident that correct information exists in the system, they initiate steps for the computer system to record entries, make payments, and generate reports for monthly closings.

Recording for the Integrated Company

In an integrated company, several divisions or subsidiaries may be involved in producing and refining oil and producing, processing, and marketing natural gas. The crude oil purchasing division may buy crude oil from the production division as it is run from the lease storage tank and may sell it to the company's own refinery or to another oil refiner. The crude oil purchasing division prepares and circulates the division order and authorizes payment to the various interest owners.

The accounting entries related to oil production and purchase by an integrated company can be classified into three groups:

1. Entries for revenue from a lease in which the company owns the working interest and sells production to another company,
2. Entries for revenue from a lease in which the company owns the working interest and purchases the production itself, and
3. Entries for purchases of oil from a lease in which the company owns no interest.

Sales by the production division to the crude oil purchasing division (and other intracompany transactions) are eliminated in preparing consolidated financial statements.

OIL INVENTORY

Virtually all E&P companies have oil in lease tanks, but the volumes and changes in inventory are typically immaterial to financial statements so most E&P companies do not bother to recognize the inventory of crude oil in lease tanks when preparing financial statements.[41] Some companies have substantial crude oil inventories, such as in remote foreign locations or on large ocean-going tankers; inventories of these types should be reflected in the financial statements.

Oil and gas inventory is recorded at the lower of cost or market (LCM). Immaterial inventory may be carried for simplicity at posted field price or similar market price. Changes in inventory carrying values are often recorded as an adjustment to lease operating expense rather than to revenues.

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[41]Only 38 percent of respondents to the *1999 PricewaterhouseCoopers Survey of U.S. Petroleum Accounting Practices* recorded oil in lease tanks as inventory.

To illustrate this procedure, assume that an E&P company's share of crude oil inventory in lease tanks at January 31, 2000, was 100 barrels carried at an LCM of $20 per barrel. The company's share of February 29, 2000, oil inventory was 60 barrels at an LCM of $19 per barrel. The necessary adjustment would decrease the recorded inventory by $860:

Beginning inventory (100 bbls @ $20)	$2,000
Less ending inventory (60 bbls @ $19)	(1,140)
Net decrease in inventory	$ 860

The customary entry on February 29 would be:

710.xxx	LOE, Change in Oil Inventory	860	
	130 Inventory of Crude Oil		860
To adjust value of inventory of crude oil on a lease.			

EXCHANGES

As mentioned in Chapter Twelve, occasionally an E&P company will exchange its crude oil for another company's crude oil, rather than sell it. Exchanges may arise to meet location, quality, or timing issues, e.g., to reduce transportation costs or to meet an integrated company's need for a different quality of crude for its local refinery.

An exchange may be structured whereby crudes are exchanged and one party receives a *differential* from the other for the agreed-upon difference in value of the crude barrels exchanged. Alternatively, the exchange may be structured as a sale of the E&P company's crude oil in exchange for the E&P company's purchase of other crude oil. Each company pays the other for the full purchase price of oil received in the exchange. Normally the acquired oil is sold the same month in which the exchange occurs. If the E&P company delivers its crude oil but fails to receive the other crude oil in the same month, the company effectively has not consummated the sale of crude oil and should not recognize a sale, but recognize a receivable (or inventory) for the crude oil to be received under the exchange.

For example, OOC delivers in June 2000, 1,000 barrels of West Texas Intermediate (WTI) crude oil in exchange for 1,100 barrels of Wyoming Sour crude to be delivered in July 2000. Because of the variation in crude quality and location, the parties agree to OOC being paid for 1,000 WTI barrels at the average June 2000 posted price for WTI and the other company being paid for 1,100 Wyoming Sour barrels at the average July

2000 posted price for Wyoming Sour crude. The June price turns out to be $20 per barrel, and the July price is $18 per barrel. OOC is to receive $20,000, and the other company will receive $19,800 from OOC. In June, OOC debits exchange receivable for $20,000 and credits marketing expense, production expense, or oil revenue for $20,000. In July, OOC receives the Wyoming Sour crude and the $200 net cash differential. OOC's July entry credits the receivable for $20,000, debits cash for $200, and debits marketing expense, production expense, or oil revenue for $19,800. When OOC sells the Wyoming crude, it credits revenue and debits accounts receivable.

ACCOUNTING FOR NATURAL GAS SALES

VALUE DETERMINATION

In Chapter Eleven, the volume of gas produced and recorded in the operating revenue subledger was stated in mcf. However, most gas sales contracts express price in terms of delivered mmBtu, not delivered mcf. Revenue (or gross value) is the quantity of mcf sold times the measured *heat content* per mcf, i.e., the mmBtu per mcf for the gas sold (also called the *Btu factor*) times the price per mmBtu. An mcf of gas with a relatively high heat content has more energy and more value than an mcf of gas with low heat content. Generally, dry natural gas that is substantially all methane has approximately 1 mmBtu per mcf.

The heat content can be determined under various conditions, but generally the sales contract will provide that heat content be determined based on *dry Btus*, i.e., the heating content in an mcf of gas measured and calculated free of moisture content. Some contracts may define *dry Btus* as each mcf having no more than seven pounds of water. If mmBtu/mcf is measured as though the mcf were saturated with water (as was required under old gas price controls), the mmBtu content would be approximately one percent less than mmBtu/mcf on a dry basis. Note that the terms *dry Btus* and *saturated Btus* refer to relative water saturation whereas the terms *dry gas* (or *residue gas*) and *wet gas* refer to NGL content.

E&P companies typically track revenue in terms of mcf sold times a price per mcf. To calculate sales price per mcf, the revenues received and recorded (and paid on a price per mmBtu) can simply be divided by the recorded corresponding gas sales volume. The price per mmBtu may also be converted to a price per mcf given the heat content, i.e., mmBtu content of an mcf of such gas. The basic conversion formula is (price/mmBtu) x (mmBtu/mcf) = price/mcf.

If the measured mmBtu/mcf reflects an mcf at a pressure base and water content inconsistent with the measured volume of mcf, then multiplying measured mmBtu/mcf by the measured volumes of mcf will not give the correct quantity of total mmBtu. In such cases, one or both measurements should be restated for consistent pressure base and water content.

Similarly, in converting a price/mmBtu to a price/mcf, a consistent pressure base and water content must be used. Typically, the heat content is converted for the pressure base and water content of the volumes recorded in the E&P company's records (generally at 14.73 psia for governmental reporting purposes). One mcf at 14.73 pounds per square inch absolute (psia) will have less density, less molecules, and less energy than an mcf at the greater pressure of 15.025 psia for the same mix of natural gases.

Pressure base and water content conversion formulas follow:

Expressing the Volume at a Desired Pressure Base:

$$\text{mcf at original psia} \times \frac{\text{original psia}}{\text{desired psia}} = \text{mcf at desired psia}$$

Expressing the Btu Factor at a Desired Pressure Base:

$$\text{mmBtu/mcf at orig. psia} \times \frac{\text{desired psia}}{\text{original psia}} = \text{mmBtu/mcf at desired psia}$$

Expressing the Btu Factor at a Desired Water Content Condition (saturated to dry):

$$\text{mmBtu/mcf at orig. psia (sat.)} \times [\text{orig. psia}/(\text{orig. psia} - 0.2561)] = \text{mmBtu/mcf at orig. psia (dry)}$$

Expressing the Volume at a Desired Water Content Condition (saturated to dry):

$$\text{mcf at orig. psia (sat.)} \times [1-(0.2561/\text{orig. psia})] = \text{mcf at orig. psia (dry)}$$

Calculating Gross Value:

mcf at desired psia (dry) x mmBtu at desired psia (dry) x price/mmBtu = Gross Value

In the following example of using the formulas above, the Btu factor is converted to the 14.73 psia.[42] The Btu factor is converted from saturated to a dry condition.[43] The mcf, measured at 14.73 psia in a dry condition, is multiplied by the mmBtu/mcf at 14.73 psia (dry) and multiplied by the contract price stated in mmBtu to arrive at the gross revenue value. Alternatively, the contract price stated in mmBtu can be multiplied by the mmBtu/mcf at 14.73 psia (dry) to arrive at the price per mcf and then multiplied by the mcf at 14.73 psia (dry). The volumes sold are 20,000 mcf at 14.73 psia (dry). The BTU factor is 1.079 mmBtu/mcf at 15.025 psia (saturated or sat.). The contract price is $2.00/mmBtu.[44] Calculations are as follows:

Step 1: 1.079 mmBtu/mcf @ 15.025 psia (sat.) x 14.73/15.025 =
1.058 mmBtu/mcf @ 14.73 psia (sat.)

Step 2: 1.058 mmBtu/mcf @ 14.73 psia (sat.) x [14.73/(14.73 - 0.2561) =
1.077 mmBtu/mcf @ 14.73 psia (dry)

Step 3: 1.077 mmBtu/mcf @ 14.73 psia (dry) x 20,000 mcf @ 14.73 psia (dry)
x $2.00/mmBtu = $43,080 gross value

or Step 3 may be expressed by first calculating the price per mcf @ 14.73 (dry):

(a) $2.00/mmBtu x 1.077 mmBtu/mcf @ 14.73 (dry) =
$2.154/mcf @ 14.73 (dry)

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[42]To convert to the same pressure base used in the volume measurement recorded in the accounting system.

[43]The water content condition was converted to a dry condition rather than the volume converted to a saturated condition as most gas contracts specify Btu measurement in a dry condition and most accounting systems will require the volume and Btu measurements recorded at a dry condition.

[44]Contract prices stated in mmBtu are independent of gas temperature or pressure. The volume and Btu factor must be stated at the same pressure base to calculate value; however, the price may be adjusted to the pressure base of the volume rather than converting the Btu factor, as long as the accountant does not convert both the price and the Btu factor.

(b) \$2.154/mcf @ 14.73 (dry) x 20,000 mcf @ 14.73 psia (dry) =
\$43,080 gross value

RECORDING GAS SALES

Recording sales of unprocessed gas involves essentially the same process as recording sales of oil.

For example, suppose that OOC operates the Margaret Theresa Lease #1. The royalty interest is 15 percent. All gas production is sold to RK Gas Resources, Inc. at \$1.92 per mmBtu assumed to equate to \$2.00 per mcf. Assume that RK Gas Resources, Inc. will make the tax payment to the state. The appropriate entry on OOC's books to receive payment for 20,000 mcf sold in June 2000, including the royalty share, less withheld production taxes of five percent, would be:

120	Accounts Receivable—Oil and Gas	38,000	
710.011	LOE—Production Taxes	1,700	
	602 Gas Revenues		34,000
	302 Royalties Payable		5,700

To record sale of gas production for June 2000

Calculations:	20,000 mcf x \$2 x 95% =	\$38,000
	20,000 mcf x \$2 x 85% x 5% =	\$1,700
	20,000 mcf x \$2 x 85% =	\$34,000
	20,000 mcf x \$2 x 15% x 95% =	\$5,700

Many automated revenue systems will make a memo entry for the total gross revenue from the property to provide for governmental and internal management reporting, and the system will allocate the amounts attributable to the working interest and royalty interest owners based on the DOI revenue deck.

When sales are made from a central delivery facility rather than the wellhead, the production department must provide the revenue accounting department with the gas sales volumes allocated by lease. The central delivery facility generally provides a statement called a *gas allocation statement* that details the allocation of sales volumes to each lease, as previously illustrated in the gas allocation example in Chapter Eleven.

The gas allocation statement may also provide the sales price, marketing costs (e.g., gas gathering charges and dehydration charges), production taxes withheld, if any, and the net sales proceeds allocated to each lease or well.[45]

GAS DEMAND CHARGES

As gas pipelines become gas transporters rather than gas purchasers, some gas producers are paying the pipelines gas demand charges to secure pipeline capacity. Such costs should be capitalized (charged to Account 280, Pipeline Demand Charges, in Appendix 5's illustrative Chart of Accounts) and amortized over the time period the capacity is available.

ACCOUNTING FOR RESIDUE GAS AND NGL SALES

RESIDUE GAS AND NGL SETTLEMENTS

Accounting for the residue gas and NGL from a plant involves complex allocations. The revenue accountant must have a clear understanding of the processing arrangements and the contract provisions. Liquids contracts, as discussed in Chapters Eleven and Twelve, may have innumerable variations, such as the measurement calculation of the products as specified in the contract terms; where the gas and/or NGL title passes; which party is responsible for transportation, processing, fractionation, marketing, and other charges; how the processor charges for processing (e.g., through a product retention or a fee per mcf, mmBtu, or gallon); and various other considerations.

Since it would be impossible to provide a discussion and the accounting entries for all situations that may be encountered in gas plant settlement accounting, this section will examine two revenue determination methods used in the industry for making payments on processed residue gas and NGL. The first, a commonly used method, provides for payment based on the allocation of actual product extracted and delivered at the plant tailgate. The second method, less used in the industry, provides for payment on a specified percentage of the theoretical volumes of residue and NGL.

Two discussions from previous chapters are relevant in this discussion: first, the discussion in Chapter Eleven on the allocation of gas at a particular measurement point (in this example, the processing plant) back

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[45]An illustration of a gas allocation statement can be found in COPAS Bulletin No. 7, *Gas Accounting Manual*.

to the individual leases; second, the theoretical gallons of liquids contained in unprocessed gas based on test results described in Chapter Eleven.

Revenue Based on Actual Product Extracted

To illustrate the first revenue determination method, assume that gas streams produced from two leases, Leases A and B, enter a processing plant. Test results taken at the wellhead provide the theoretical amount of gpm (gallons per mcf) of each liquid that may be produced from the stream of gas at a particular wellhead. The gas is again measured and tested at the plant inlet. The test results taken at the plant inlet yield a total mcf and a gpm based on the combination of Leases A and B gas streams into the plant. The plant inlet volumes are allocated back to Leases A and B. Volumetric and quality measurements are taken at the plant's tailgate. The basis for the settlement payment is typically the quantities extracted and delivered for sale during the month. In this example, only the calculations for the ethane are illustrated.

Assumptions:	Lease A	Lease B	Total
Wet gas (mcf) processed	24,000	20,000	44,000
Ethane theoretical gpm at lease	0.120	0.100	
Actual ethane sold (gallons)			4,600
Producers’ negotiated share of ethane	70 %	65 %	
Processor’s share as a processing fee	30 %	35 %	
Actual ethane price per gallon			$ 0.210

Ethane Revenues:	Lease A	Lease B	Total
Wet gas (mcf)	24,000	20,000	44,000
x ethane theoretical gpm	x 0.120	x 0.100	
= ethane theoretical gallons	2,880 +	2,000 =	4,880 (a)
Total actual ethane gallons sold			4,600 (b)
Plant's ethane recovery factor, (b)/(a)			0.9426
Applied to each lease	x 0.9426	x 0.9426	
Actual ethane allocated by lease	2,715 +	1,885 =	4,600
Producers' negotiated share	x 70 %	x 65 %	
Producers' settlement volumes	1,900	1,225	
Ethane price per gallon	x $ 0.210	x $ 0.210	
Allocated ethane revenue	$ 399	$ 257	

In our example, the processing plant was able to extract almost 95 percent of the ethane that was theoretically determined to be in the gas stream. The quantity of salable liquids actually recovered in the plant differs from the theoretical liquid content of the gas volume owing to variations between the test conditions, plant operating conditions, designed operating efficiency of the plant, and processing losses.

The ratio of a plant's actual volumes to theoretical volumes is called the *recovery factor*. A recovery factor is calculated for each individual product extracted in the plant. The recovery factor is multiplied by the theoretical gallons of the product for each lease to determine the allocated volumes. Generally contracts provide for separate settlement calculations for each of the individual components extracted.

The second revenue determination method used in plant processing contracts may provide for payment based on a specified percentage of the theoretical gallons of gasoline rather than the actual gallons extracted from the product. In theory, settlement based on theoretical gallons may result in the producer's negotiated share being lower than if settlement were based on actual gallons extracted. For this second example, the same facts as in the prior example are assumed except that the producers' negotiated shares of ethane sales are 67 percent and 62 percent for Leases A and B, respectively. For the second example, the ethane revenues allocated to Leases A and B would be as follows:

	Lease A	Lease B
Wet gas (mcf)	24,000	20,000
x ethane theoretical gpm	x 0.120	x 0.100
= ethane theoretical gallons	2,880 +	2,000
Producers' negotiated share	x 67 %	x 62 %
Producers' settlement volumes	1,930	1,240
Actual ethane price per gallon	x $ 0.210	x $ 0.210
	$ 405	$ 260

In this case the producer does not share in the risks of the plant operation but receives a negotiated straight percentage of theoretical volumes.

Variations

The producer may be paid on a *sliding scale* percentage of the price per gallon, with the percentage varying according to either, or both, the price and the gpm of the gas. The lower the price and/or the gpm, the smaller the percentage due the producer; conversely, an increase in the price or gpm increases the percentage due the producer. While a sliding scale approach is more complicated, it reduces the range of the processing fee to more closely approximate the plant operator's processing costs and provides the operation with steady profits. The producer assumes more risk of changes in NGL prices and gas quality.

Contracts may specify that the payment to the producer is based on the processor's gross NGL sales proceeds or based on proceeds after deduction of cash discounts, transportation costs, or marketing costs.

NGL Inventory

Producer-owned inventory balances at the plant are rare. Most plants are connected by a pipeline system that allows for residue gas and products to be moved as soon as extracted. However, some NGL may be stored in pressurized tanks at the plant and later removed by truck.

It is also possible for a producer to be allocated NGL sales in a manner that creates a negative inventory or overdelivery attributable to the producer's account.

GAS PLANT SETTLEMENT STATEMENT

The gas plant settlement statement in Figure 13-2 is an example of required information to make the appropriate accounting entries to record the sale of residue gas and liquids. It would be inaccurate to state that this is a typical gas plant settlement statement given the multitude of contract arrangements that are possible and the wide range of formats used by plant operators. Gas plant settlement statements vary widely; however, they generally contain:

- The mcf, Btu content, and the mmBtu of unprocessed gas received from the producer allocated to the lease or delivery point;
- The residue gas returned to the lease (for injection or fuel usage);
- The residue gas available for sale to a purchaser or end user and the residue gas sold by the plant (if provided for in the agreement);

- An inventory of the volumes by NGL product;
- The gross value of the separate NGL products; and
- Processing fee deductions by NGL product in the form of a percent of product or charge per gallon, mcf, or mmBtu.

Settlement statements may also contain:

- Liquid loss volumes by product, production tax amounts, or other charges and
- The net value, after deductions, for each separate NGL product.

The gas plant settlement statement in Figure 13-2 depicts June 2000 NGL and residue gas sales for the Margaret and Angeline leases paid under different contract settlement terms reflected by two different contract agreement numbers. The following assumptions are applied to the Margaret lease:

- The gas processing contract specifies that the processor will sell the residue gas and NGL for the producer (the propane will be taken in kind by the producer).
- The producer is paid on an allocation of actual product.
- The processing contract specifies that the processor will retain 16 percent of the actual volumes produced of each NGL and the residue gas.
- The contract provides for the processor to be paid (1) a transportation fee of $0.035 per gallon of NGL available for sale and $0.04 per mmBtu of residue gas available for sale and (2) a marketing fee of $0.0025 per NGL gallon sold and $0.003 per mmBtu of residue gas sold.
- A small negative inventory balance for ethane exists at June 1, 2000.
- The producer is responsible for paying the state production tax.
- The producer is responsible for distributing the sales proceeds to the other interest owners.

Figure 13-2: A Gas Plant Settlement Statement

SETTLEMENT STATEMENT FOR: BIG OIL USA, INC.

DONALD JAMES PROCESSORS, INC.
Production Month: June 2000

SUMMARY OF PRODUCT PAYMENT: BIG OIL USA, INC. — PAGE 1

Lease # and Name		Contract #		AVAILABLE VOLUME	TAKE-IN-KIND	VOLUMES DELIVERED	GROSS	LESS TRANSP. (a)	LESS MRKTNG. (b)	NET DUE
9738293	Margaret	17465-23	NGL (gal)	32,948	5,078	27,674	$9,715.16	$1,153.20	$69.19	$8,492.77
9738293	Margaret	17465-23	Gas (mmBtu)	249,762		249,762	$330,508.48	$9,990.48	$749.29	319,768.71
9732387	Angeline	16984-45	NGL (gal)	34,200	0	34,200	$12,041.53	$12,041.53	$85.50	10,759.01
9732387	Angeline	16984-45	Gs (mmBtu)	189,781	189,781	0				$0.00
										$339,020.49

(a) Transportation = $0.035/Gal. and $0.04/mmBtu of available volumes (b) Marketing Fee = $0.0025/Gal. and $0.003/mmBtu of volumes delivered.

LIQUIDS PRODUCTION — Lease: Margaret — PAGE 2

			PRODUCT	GPM	THEORETICAL GALLONS	RECOVERY FACTOR	ACTUAL GALLONS	CONTRACT PERCENT	PRODUCER ENTITLEMENT
Contract #:	17465-23								
Prod. Mo.:	06/00	Alloc. Inlet							
Lease #:	9738293	mcf:	ETHANE	0.1020987	23,965	0.72854864	17,460	0.84	14,666
Lease Name:	Margaret	256,439	PROPANE	0.0318178	6,054	0.99854328	6,045	0.84	5,078
County:	Hidalgo		I-BUTANE	0.0030644	565	0.98738554	558	0.84	469
State:	Texas	Alloc. Inlet	N-BUTANE	0.0382929	7,099	0.98775937	7,012	0.84	5,890
Btu Content:	1.1203	mmBtu	PENTANES	0.0703337	12,087	0.83302638	10,569	0.84	8,878
Pressure Base:	14.65	287,289							
Contract Btu:	Dry				50,170		41,643		34,981

LIQUIDS GROSS VALUE — Lease: Margaret

PRODUCT	PRODUCER'S ENTITLEMENT	PRODUCER'S BEGINNING INVENTORY	AVAILABLE FOR SALE	IN-KIND GALLONS	GALLONS DELIVERED	PRODUCER ENDING INVENTORY	GALLONS DELIVERED	PRICE/GAL.	GROSS
ETHANE	14,666	(2,032)	12,634	0	12,634	0	12,634	$0.239880	$3,030.67
PROPANE	5,078	0	5,078	5,078	0	0	0	$0.358690	0.00
I-BUTANE	469	0	469	0	469	0	469	$0.446590	209.28
N-BUTANE	5,890	0	5,890	0	5,694	196	5,694	$0.431120	2,454.80
PENTANES	8,878	0	8,878	0	8,878	0	8,878	$0.452870	4,020.41
	34,981	(2,032)	32,949	5,078	27,675	196	27,675		$9,715.16

Figure 13-2: A Gas Plant Settlement Statement (cont.)

RESIDUE GAS GROSS VALUE — Lease: Margaret

	RESIDUE VOLUMES, mmBtu								
ALLOCATED INLET	PRODUCT SHRINKAGE	THEORETICAL REMAINING	RESIDUE ALLOCATION	ACTUAL RESIDUE	RESIDUE RETURN	RES. AVAIL. FOR SALE	CONTRACT PERCENT	RESIDUE GAS PRICE/mmBtu	RESIDUE GROSS
287,289	29,343	257,946	0.968274	249,762	0	249,762	0.84	$1.575348	$330,908.14

LIQUIDS PRODUCTION — Lease: Angeline — PAGE 3

			PRODUCT	GPM	THEORETICAL GALLONS	CONTRACT PERCENT	ENTITLEMENT GALLONS	TAKE-IN-KIND GALLONS	TOTAL GALLONS
Contract #:	16984-45								
Prod. Mo.:	06/00	Alloc. Inlet							
Lease #:	9732387	mcf:	ETHANE	0.1020987	17,392	0.8450	14,696		14,696
Lease Name:	Angeline	170,345	PROPANE	0.0318178	5,420	0.8025	4,350		4,350
County:	Woodward		I-BUTANE	0.0030644	522	0.8250	431		431
State:	Oklahoma	Alloc. Inlet	N-BUTANE	0.0382929	6,523	0.8200	5,349		5,349
Btu Content:	1.1141	mmBtu	PENTANES	0.0703337	11,981	0.7825	9,375		9,375
Pressure Base:	14.65	189,781							
Contract Btu:	Dry				41,838		34,201		34,201

LIQUIDS GROSS VALUE — Lease: Angeline

		PRODUCT	GALLONS AVAILABLE FOR SALE	GALLONS DELIVERED	PRICE/GAL	GROSS
Contract #:	16984-45					
Prod. Mo.:	06/00					
Lease #:	9732387	ETHANE	14,696	14,696	$0.259320	$3,811.03
Lease Name:	Angeline	PROPANE	4,350	4,350	$0.376230	1,636.43
County:	Woodward	I-BUTANE	431	431	$0.464320	199.96
State:	Oklahoma	N-BUTANE	5,349	5,349	$0.443020	2,369.65
Btu Content:	1.1141	PENTANES	9,375	9,375	$0.429270	4,024.46
Pressure Base:	14.65					
Contract Btu:	Dry		34,201	34,201		$12,041.53

RESIDUE GAS GROSS VALUE — Lease: Angeline

	RESIDUE VOLUMES, mmBtu								
ALLOCATED INLET	PRODUCT SHRINKAGE	THEORETICAL REMAINING	RESIDUE ALLOCATION	ACTUAL RESIDUE	RESIDUE RETURN	RES. AVAIL. FOR SALE	CONTRACT PERCENT	RESIDUE GAS PRICE/mmBtu	RESIDUE GROSS
189,781	18,432	171,349	0.912708	156,392	156,392	0	0	$1.575348	$0.00

The assumptions that apply to the Angeline lease in Figure 13-2 are the same as for the Margaret lease except for the following:

- The gas processing contract specifies that the processor will buy the NGL and that the residue gas will be returned to the producer.
- A processing fee of $0.05 per mmBtu of residue gas will be separately invoiced.
- The NGL volumes attributable to the producer's account are based on a contract percentage of theoretical gallons for each product.

When recording the accounting entries for the Figure 13-2 sales, assume the following for the Margaret and Angeline leases:

- Big Oil records only the NGL volumes and values attributable to its 84 percent contract percent (the *net-back* method).[46]
- Big Oil has a 50 percent net revenue interest. Big Oil has an agreement with the other interest owners that the processing fees, transportation, and marketing charges from the processing plant are marketing costs to be shared in proportion to net revenue interests. Big Oil's working interest percentage is not used for this example.
- Big Oil records the volume and value of the delivered (i.e., sold) residue gas and NGL, rather than the produced amounts because the inventory amounts at the processor's plant are immaterial.
- The state production tax rate is 7.5 percent of the value of the residue gas and NGL (no marketing or other deductions from the gross value are allowed, and there are no state or federal royalty interests that are exempt from the production tax).[47]

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[46]Recording the net volume of gas (the actual gross volume of NGL extracted less the volume charged as a processing fee by the processor) seems to be the method used most frequently by industry revenue accountants. Generally, given the small NGL volumes and values compared with total company energy volumes and values, recording NGL revenues net of the processing fee rather than recording the processing fee as an expense becomes a question of materiality for a particular entity to address.

[47]In some states there are regulations that apply to certain types of processing plants, and the plants may have the responsibility for the calculation of the state production taxes, as the processing plant statement may not contain adequate information for the producer to make accurate calculations. The tax calculations and deductions will appear on the plant settlement statement.

Big Oil makes the following calculations related to its 50 percent interest in the sale of residue gas and NGL from the Margaret lease. Transportation expenses are classified as a marketing expense.

	Total	Big Oil USA	Other Owners
Residue gas sales	$330,508	$165,254	$165,254
Marketing expenses	(10,740)	(5,370)	(5,370)
Production taxes	(24,788)	(12,394)	(12,394)
Net gas proceeds	$294,980	$147,490	$147,490
NGL gas sales	$9,715	$4,857	$4,858
Marketing expenses	(1,222)	(611)	(611)
Production taxes	(729)	(364)	(365)
Net NGL proceeds	$7,764	$3,882	$3,882

The corresponding accounting entries are as follows:

120	Accounts Receivable	319,768	
702	Gas Marketing Expense	5,370	
710.011	Production Taxes	12,394	
	320 Production Taxes Payable		24,788
	302 Revenue Distributions Payable		147,490
	602 Gas Revenues		165,254

To record June 2000 residue gas sales, Margaret lease.

120	Accounts Receivable	8,493	
703	NGL Marketing Expense	611	
710.011	Production Taxes	364	
	320 Production Taxes Payable		729
	302 Revenue Distributions Payable		3,882
	603 NGL Revenues		4,857

To record June 2000 NGL sales, Margaret lease.

The corresponding accounting entry to record NGL sales allocated to the Angeline lease is as follows:[48]

120	Accounts Receivable	10,759	
703	NGL Marketing Expenses	642	
710.011	Production Taxes	451	
	320 Production Taxes Payable		903
	302 Revenue Distributions Payable		4,928
	603 Plant NGL Sales Revenue		6,021

To record June 2000 NGL sales, Angeline lease.

A company may also choose to record 100 percent of the residue gas and NGL volumes and values as revenue, recording the difference between 100 percent and the contract percent as a processing fee. This may be the desired method of accounting when interest owners' lease agreements specify royalty payment on 100 percent of the value of the NGL extracted, not allowing a reduction of the royalty for volumes taken by the processor. Some lease agreements may specify minimum royalties on the NGL. Other may specify that royalties are based on the actual volumes and prices received by the plant owner rather than a contract percentage on the theoretical volumes, as in the Angeline processing agreement.

If the processing fee exceeds the state taxing authority's allowable deduction in computing the production tax, the net-back method may create accounting system problems in calculating and paying the correct amounts to state tax authorities. Generally, the fees charged by the processing companies will fall within the state's allowable limits. The revenue accountant should be aware of the state's tax regulations to avoid penalties on underpaid production taxes.

Revenue accountants may receive plant statements that calculate both the value of the unprocessed gas and the combination of the values of the residue gas and NGL. This generally is the result of a *keep-whole provision* in the contract that places the risk of processing the gas in the hands of the processor. The producer receives the higher value of the two calculations. The accounting entries for the value received are recorded as shown for unprocessed gas in the earlier *Accounting for Natural Gas Sales* section or as shown in this section for the sales of residue gas and NGL.

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[48]An entry to record the gas taken in kind, processing charges, and related production taxes would also need to be made; the entry would be dependent on the disposition of the in-kind gas.

Dual accounting (which is the same as the *keep-whole provision* described above) is a requirement for gas plant processing with the Mineral Management Service and Indian tribe royalties. When gas is flowing through an operated gas plant, the MMS will be paid the higher of (1) the total of the NGL cumulative sales, plus the residue sales or (2) the unprocessed (wet) gas value. In rare instances, other royalty owners receive similar keep-whole pricing under their lease agreements.

SPECIAL ROYALTY PROVISIONS

In addition to the basic fractional royalty provided in all oil and gas lease contracts, two other royalty provisions are very common. These two provisions, introduced in Chapter Seven, are called shut-in royalties and guaranteed minimum royalties. These special provisions may involve either oil or gas but more often are applicable to gas wells.

SHUT-IN ROYALTIES

The standard lease agreement provides for the payment of *shut-in royalties* in the event that it is necessary, because of a lack of market or marketing facilities, to shut in a well capable of production. These payments in lieu of production must be made to prevent forfeiture of the lease. If a shut-in royalty payment is not recoverable from future production, it is similar in nature to *ad valorem* taxes assessed on proved property fair value (which are operating expenses) and to delay rentals (which are carrying costs of undeveloped property charged under successful efforts to exploration expense and under full cost to capitalized lease acquisition costs). However, a shut-in royalty occurs after proved reserves are discovered and is not truly an exploration cost or carrying cost of undeveloped property. Hence a company using either successful efforts or full cost would typically charge the shut-in royalty to a lease operating expense account. Recording the shut-in royalty to lease operating expense is appropriate even when the shut-in royalty amount is the same as the delay rental amount as provided in Section 3 of the gas lease in Figure 7-1. Nonrecoverable shut-in royalties are generally immaterial to company financial statements.

If the payment is recoverable from future production, it is usually considered as a recoverable advance payment and is recorded as an account receivable by both full cost and successful efforts companies, if it is reasonably certain that recovery will take place. If a receivable account is used, the amount charged to the account should be limited to the amount that can reasonably be expected to be recovered from future royalty revenues in excess of the guaranteed amount. Any amount paid in excess of amounts reasonably anticipated to be recovered should be charged to lease operating expense.

Entries to illustrate the different procedures for recording shut-in royalties are shown below, assuming that a shut-in payment of $1,000 was made in the first month (in which there was no production) and that the second month's sales were 2,000 mcf at $2.00 per mcf. The royalty interest is one-eighth, and taxes have been ignored.

Payment Not Recoverable from Future Production:

710.19	Shut-in Royalty Expense	1,000	
	302 Revenue Distributions Payable		1,000

To record a shut-in royalty.

Payment Recoverable from Future Production:

126	Accounts Receivable—Other	1,000	
	302 Revenue Distributions Payable		1,000

To record shut-in royalty recoverable from future production.

120	Accounts Receivable (2,000 mcf @ $2.00)	4,000	
	602 Gas Revenues (7/8)		3,500
	302 Revenue Distributions Payable (1/8)		500

To record sale of gas.

302	Revenue Distributions Payable	500	
	126 Accounts Receivable—Other		500

To apply royalty on current production against recoverable amount (balance recoverable, $500).

GUARANTEED MINIMUM ROYALTIES

The lease agreement may stipulate *guaranteed minimum royalties* whereby the lessor receives a minimum royalty each year regardless of the amount of production. For example, Section 4(I) of the State of Texas leasing form in Appendix 7 calls for a minimum annual royalty after the lease's primary term equal to the annual primary term's annual delay rental. Payments made on this guaranteed basis are sometimes called *fixed cash* *royalties* and are normally recorded as a lease operating expense if incurred after proved reserves are recognized.

Nonrecoverable Minimum Royalties

When the lessor is guaranteed a nonrecoverable minimum amount of royalty each period and the value of the lessor's portion of the oil or gas produced is less than that minimum amount, then the required deficiency payments to the royalty owner are customarily treated as production expenses by both successful efforts companies and full cost companies.

Assume that a nonrecoverable minimum royalty of $600 per month is to be paid. The first month's delivery of gas was 1,000 mcf at $2.00 per mcf. The 1/8th royalty earned is $250, i.e., 1/8 x $2,000. The gas revenue and minimum royalty would be recorded as follows:

120	Accounts Receivable (1,000 @ $2.00)	2,000	
710.19	Minimum Royalty Expense ($600-$250)	350	
	602 Gas Revenues (7/8 x $2,000)		1,750
	302 Revenue Distributions Payable		600

To record lease sale of gas. Excess of minimum royalty over 1/8 of production charged to lease operating expense.

Some producers, however, reduce their shares of revenues by the full amount of the minimum royalty paid the lessor regardless of whether the full amount has been earned out of production. This approach has theoretical merit but distorts revenue per unit from the average sales price and hinders management's review of sales activity. The following entry illustrates the entry to record payment as a reduction of revenue:

120	Accounts Receivable	2,000	
	602 Gas Revenues (7/8)		1,400
	302 Revenue Distribution Payable		600

To record sale of gas and to record minimum royalty.

Recoverable Minimum Royalties

As in the case of shut-in royalties, if deficiency amounts of minimum royalties are recoverable from future production and it can be reasonably anticipated that future recovery will be made, it is appropriate to charge the minimum payments to an accounts receivable account or to an advance payment account.

To illustrate recoverable guaranteed royalties, assume that a property is burdened with a minimum royalty of $2,500 per month recoverable from future royalties earned in excess of the minimum. Production for the first six months of the contract was as follows: January, February, and March, no production; April, 4,000 mcf; May, 12,000 mcf; and June, 80,000 mcf. The selling price was $2 per mcf, and production taxes are ignored for the sake of simplicity. A schedule of recoverable minimum royalties is as follows:

Month	Royalty Paid	Royalty Earned	Excess Paid Over Earned	Cumulative Recoverable Balance
January	$ 2,500	$ 0	$ 2,500	$ 2,500
February	2,500	0	2,500	5,000
March	2,500	0	2,500	7,500
April	2,500	1,000	1,500	9,000
May	2,500	3,000	(500)	8,500
June	11,500	20,000	(8,500)	0

It should be emphasized again that if recoverable guaranteed amounts are paid, any amounts recorded as a receivable should generally be charged to lease operating expense if and when it becomes likely that the amount would not be recoverable.

ACCOUNTING FOR REINJECTED GAS

The accounting treatments given to different types of injection operations are often identical. However, accounting varies with the source of the natural gas as discussed below.

GAS CYCLING

One Lease

When gas is produced from and reinjected into the same reservoir pursuant to a single lease agreement (or unitization agreement, discussed in Chapter Twenty-Three), no ownership equity is disturbed and no royalty payments are necessary. Also production taxes are generally not payable on gas injected into the same lease. It seems logical to assume that this operation is conducted initially for the purpose of extracting liquids, because the injection does not enhance the value of the gas or reduce the cost of producing the gas when it is ultimately sold. It follows, therefore, that no value should be assigned to the reinjected gas, that all of the income and lifting cost should be assigned to the liquids until gas is actually sold, and that statistical records should be maintained only for the gas reinjection. Only when injected gas is again produced and sold should it be included in sales figures and recorded as lease revenue.

Multiple Leases

A similar situation exists when a single reservoir into which gas is being reinjected underlies more than one tract leased by the same group of working interest owners. The treatment of the working interests' shares of gas would be the same as in the single lease situation discussed above. However, a question of royalty payments arises because some of the gas may be produced on one lease and injected on another lease with a different royalty owner. The most desirable solution to this problem is to secure royalty owners' agreements to unitize which, in effect, would convert the several leases to a single property. Injections using one lease's wells may increase production from wells on other leases producing from the same reservoir. In the absence of such an agreement and assuming that a royalty must be paid each time the gas is produced and leaves a lease, these royalty payments should be charged to the lease benefiting from the injection operations. All of the expense should be considered lifting costs attributable to any oil and NGL produced from the reservoir. As in the case of gas reinjected into the lease from which it was produced, none of the injected volumes should be included in revenues of the working interest owners.

GAS ACQUIRED FROM OTHER SOURCES (EXTRANEOUS GAS)

A more involved situation presenting additional accounting problems exists if the gas used for injection (often as part of a secondary or tertiary recovery program) is either purchased from outsiders (including royalty owners) or transferred from other reservoirs owned by the producer conducting the injection program. Situations of this type are typical of many pressure maintenance operations involving the injection of gas or a combination of gas and products. It is for this reason that frequent reference will be made in the following discussion to pressure maintenance operations. Since the accounting problems applicable to injected gas are identical to those involving injected products, the discussion below is applicable to both gas and products.

There are three general ways to account for the cost of injected purchased gas:

- Expense as incurred,
- Capitalize as cost of wells and development, or
- Capitalize as a deferred charge to be credited as the injected gas is reproduced.

If the injectant costs are recurring over the property's productive life and are not recoverable, they may simply be expensed as incurred. Reproduction and sale would be recorded as current revenue (or perhaps as a reduction of production expense).

Some accountants favor charging purchases of extraneous gas and products for pressure maintenance to the well and facilities account, especially in the case of full cost companies. In this case the costs would be amortized on the basis of units produced.

Still other companies may treat the cost of reinjected gas or products as a deferred charge (without amortization) until the material is recovered. The deferred charge account represents, in effect, an inventory account. It appears to be generally agreed that if gas or product purchases are to be treated as deferred charges, the amount recorded as an asset should represent only the recoverable value of the gas or products, and the difference between the purchase price and the amount recoverable should be charged to pressure maintenance expense of the injected reservoir at the time of injection.

If extraneous gas is injected into a reservoir, it is customary for agreements to be made with royalty owners of the leases into which gas is being injected, permitting the later recovery of the extraneous gas without royalty payments. One important factor in determining the appropriate accounting procedure is whether all the gas and products injected will be recoverable. Generally, some injected products and gas will remain in reservoirs because it would not be economically feasible to recover all of the product and gas injected.

A cumulative record of gas injected must be maintained, and the volume of *reproduced* gas must be determined when sales are subsequently made.

Production taxes and royalty payments may not be due on reproduced gas. Determination methodology varies:

1. Use the method prescribed by the tax authority or lease agreement,
2. Assume all injected gas is reproduced before any gas reserves,
3. Assume all injected gas is produced after estimated reserves, or
4. Assume proportionate production.

Gas Purchased from Others

Illustrated below are journal entries to record the purchase and subsequent reproduction of injected commodities acquired from outsiders, including the amount *purchased* from royalty owners on leases from which gas is transferred. First, it is assumed that the injected gas is charged to expense as incurred. In the next example, it is assumed that the injected gas is charged to a deferred charge account. Finally, it is assumed that the gas is capitalized as Costs of Wells and Development.

Recorded as an Expense

710.21	Operating Expense—Pressure Maint., Lease A	1,000	
	301 Vouchers Payable		1,000

To record purchased gas injected in Lease A.

120	Accounts Receivable—Oil and Gas Sales	1,200	
	602 Gas Revenues, Lease A		1,200

To record sale of produced natural gas.

Recorded as a Deferred Charge

293	Other Deferred Charges	1,000	
	301 Vouchers Payable		1,000

To record gas purchased for injection in Lease A.

120	Accounts Receivable—Oil and Gas Sales	1,200	
	293 Other Deferred Charges		1,000
	630 Misc. Operating Income (or Lease Operating Expenses), Lease A		200

To record sale of natural gas previously injected.

Recorded as Capitalized Costs of Wells and Development

231.005	Intangible Costs of Wells and Development, Enhanced Recovery Projects	1,000	
	301 Vouchers Payable		1,000

To record gas purchased for injection in Lease A.

120	Accounts Receivable—Oil and Gas Sales	1,200	
	602 Gas Revenues, Lease A		1,200

To record sale of gas from Lease A.

Under this approach, the amount of cost capitalized ($1,000) would become a part of the basis for amortization of wells and related equipment and facilities. The current period's depreciation provision would include amortization of the injected gas costs.

Gas Transferred from Another Lease of the E&P Company

Although gas production and reinjection by the same company are not revenue and expense, they may be recorded as such for internal management purposes to better track each field's performance. The E&P company might credit the company's revenue from the producing lease and charge the pressure maintenance account of the injected lease, reversing the entry for external financial reporting if significant.

This procedure for handling the value of the E&P company's share of production reinjected in another lease is illustrated below:

Entry to Record Injection

710.021	LOE—Pressure Maintenance, Lease A	1,000	
	602 Gas Revenue, Lease B		1,000

To record transfer of injected gas from Lease B to Lease A.

Consolidating Entry

602	Gas Revenue, Lease B	1,000	
	710.021 LOE—Pressure Maintenance, Lease A		1,000

To eliminate intracompany income on the transfer of gas from Lease B to Lease A.

120	Accounts Receivable—Oil and Gas	1,200	
	602 Gas Revenue, Lease A		1,200

To record sale of produced natural gas.

Chapter Fourteen

GAS IMBALANCES

INTRODUCTION

If a gas producing company nominates, sells, and delivers to a customer more gas (e.g., five mmcf) from a pipeline than the volume of gas the producer puts into the pipeline, the gas producer has a *pipeline gas imbalance,* owing the gas volume (e.g., five mmcf) or cash equivalent to the pipeline. Such an imbalance may also be called a *producer/ transporter gas imbalance* or *a shipper/transporter gas imbalance*.

In turn, a working interest owner (WI) may be allocated and sell a volume of gas different from the owner's entitled share of production, creating a *producer gas imbalance* also called a *producer/producer gas imbalance*. For example, WI Owner A could take and sell in a month one mmcf more than the owner's entitled net revenue interest share, and other WI owner(s) in the property would necessarily take and sell that month one mmcf less than their entitled shares. This creates a producer gas imbalance of one mmcf owed by Owner A to the other owner(s). Owner A is said to have an *over-take or overlift*, and the other owners have an *under-take or underlift*. The imbalance is typically settled by the other owner(s) taking one mmcf extra from the property's future production. However, the imbalance might be settled by Owner A paying cash to the other owners many years later.

How should the gas imbalances be recorded in the financial statements? Should Owner A record payables on its balance sheet? If so, at what values? Or, for the producer gas imbalance, should Owner A reduce its share of the property's proved reserves since the other owners now have a right to take one mmcf of Owner A's share of future production? Who is responsible for paying the royalties and production taxes on the one mmcf of gas production sold by Owner A instead of the other owner(s)? This chapter addresses such questions.

For pipeline gas imbalances, the general responsibility and rights of the parties are largely established by prior contractual agreement and by pipeline rules subject to the approval of FERC. For producer gas imbalances, the responsibilities and rights of the joint venture's WI owners are ideally provided in a *gas balancing agreement* (GBA), often attached as an exhibit to the joint operating agreement. However, many operating agreements signed prior to the mid-1980s do not contain GBAs.

Minimizing and accounting for pipeline and producer imbalances require extensive coordination between operators, nonoperators, consumers, and pipeline companies. COPAS Bulletins Number 24 *Producer Gas Imbalances* and No. 28 *Joint Task Force Guidelines on Natural Gas Administrative Issues* provide accounting guidelines for producer and pipeline imbalances. In addition, the SEC has provided guidance regarding the valuation of receivables and payables related to producer imbalances.

PIPELINE GAS IMBALANCES

ROLES OF THE OPERATORS AND NONOPERATORS

A field operator is responsible for monitoring and controlling the flow of gas production from the field's wells. In order to facilitate the nomination process, the operator provides estimates of monthly production to the nonoperators in order for them to determine their available deliverability. Nonoperators that choose to market their own gas must establish a market for their gas and are responsible for providing a nomination to the well operator or the pipeline company. Subsequent to the month of gas flow, the pipeline company prepares a monthly production volume allocation statement, which allocates the actual production to each working interest owner. The nonoperator should review the production volume allocation statement and resolve any differences with the operator or the pipeline company.

NOMINATION PROCESS

In order for a producer to market his own gas, he makes a nomination to the operator or the pipeline company, as discussed in Chapter Twelve. If the pipeline's capacity exceeds the total of the nominated volumes, the nomination is confirmed (*confirmed nomination*). If the total of the nominated volumes exceeds the pipeline's capacity, the pipeline allocates its capacity based on service type (firm versus interruptible transportation). The nominations are revised, and the producers and pipeline agree to a confirmed nomination. The producer's customer also contacts the pipeline company in order to confirm its nominated receipt volume. Differences between confirmed nominations and actual gas flow must be minimized in order to avoid pipeline imbalance penalties. If actual production varies significantly from the confirmed nomination, the operator modifies the physical gas flow, or the nominations are revised.

ALLOCATION PROCESS

Physical gas flow seldom equals the total of the confirmed nominated volumes. Consequently, the parties involved (operators, pipelines, shippers) execute agreements that determine an allocation method prior to physical flow (*predetermined allocation methodology*). These agreements should consider the contractual and regulatory issues related to the allocation method. Common allocation methods include pro-rata-allocation based on confirmed nominations and allocation based on entitlements. The agreements should also specify the party responsible for preparing the monthly *production volume allocation statement*, the timing of the allocation statement preparation, and the format of the allocation statement. The statement should be reviewed by the other working interest owners, and any discrepancies should be communicated. The producer should record any overdeliveries or underdeliveries to the pipeline as receivables or payables, respectively.

The following illustration provides an example calculation of allocations using both the confirmed nominations method and entitlements method.

A property owned 60 percent by Owner A and 40 percent by Owner B is expected to produce 100,000 mcf of gas in the following month. Owners A and B make confirmed nominations of 70,000 mcf and 30,000 mcf, respectively. The mainline pipeline index price is $1.90 mmBtu equating to $2/mcf. If the actual production were 80,000 mcf, the allocations based on the confirmed nominations method and the entitlements method would be calculated as follows:

Confirmed Nomination Allocation:	Owner A	Owner B
Total actual production	80,000 mcf	80,000 mcf
Percentage of production nominated	x 70%	x 30%
Allocated actual production	56,000 mcf	24,000 mcf

Entitlement Allocation:	Owner A	Owner B
Total actual production	80,000 mcf	80,000 mcf
Ownership percentage	x 60%	x 40%
Allocated actual production	48,000 mcf	32,000 mcf

Assuming the pipeline company delivers each owner's confirmed nomination to the owner's customers, Owners A and B would record a pipeline imbalance receivable or payable for the overproduced or underproduced volumes as follows:

Confirmed Nomination Allocation:	Owner A	Owner B
Allocated production	56,000 mcf	24,000 mcf
Less confirmed nomination	(70,000 mcf)	(30,000 mcf)
Gas imbalance payable to pipeline	(14,000 mcf)	(6,000 mcf)
x Pipeline index price	x $2/mcf	x $2/mcf
Pipeline imbalance liability	$ (28,000)	$ (12,000)

Owners A and B would record a pipeline imbalance liability of $28,000 and $12,000, respectively. Owner A has been allocated 56,000 mcf and paid sales proceeds on that basis although its 60 percent NRI share is 48,000 mcf. So there is also a producer gas imbalance of 8,000 mcf owed by Owner A to Owner B, giving Owner A imbalances netting to 22,000 mcf payable and giving Owner B imbalances netting to 2,000 mcf receivable.

Entitlement Allocation:	Owner A	Owner B
Allocated production	48,000 mcf	32,000 mcf
Less confirmed nomination	(70,000 mcf)	(30,000 mcf)
Gas imbalance receivable from (payable to) pipeline	(22,000 mcf)	2,000 mcf
x Pipeline index price	x $2/mcf	x $2/mcf
Pipeline imbalance asset (liability)	$ (44,000)	$ 4,000

Owner A would record a pipeline imbalance payable of $44,000, and Owner B would record a pipeline imbalance receivable of $4,000. Notice that under the entitlement allocation method, Owner A owes no gas to Owner B, i.e., there is no *producer gas imbalance*. Rather Owner A owes the entire 22,000 mcf imbalance to the pipeline.

SETTLEMENT PROCESS

In addition to producers and transporters agreeing to a predetermined allocation methodology, they should also establish predetermined resolution procedures to settle imbalances. Subsequent to the implementation of FERC Order 636, imbalance trading, volumetric make-up, and cash in/out became the three most common methods to settle pipeline imbalances. Under the imbalance trading method, two different shippers on the same pipeline can trade their under- and overdelivered positions in order to negate their imbalances. Volumetric imbalance make-ups involve the producer separately identifying and nominating additional or lesser volumes in order to settle under- or overdeliveries. Under the cash in/out method, the producer pays or receives cash for pipeline imbalance under- or overdeliveries.

The above example uses a mainline index price to value the under- and overdeliveries. The imbalance should be valued in accordance with the contractual requirements of the pipeline's tariff, which may require that imbalances be valued at current mainline index prices, the pipeline's weighted average cost of goods sold (WACOG), a weighted average sales price, or some other method. Additionally, a pipeline company may assess penalties for imbalance volumes that exceed imbalance tolerances defined in the tariff. Producers should assess the carrying value of unsettled pipeline imbalances to ensure that the amounts are valued in accordance with the pipeline tariff and the applicable penalties have been properly accrued.

Accounting. Pipeline gas imbalances are generally recorded as accounts receivable or payable at values consistent with contractual arrangements with the pipeline company. Informal SEC staff interpretations have called for valuing an imbalance receivable at the lowest of (a) the gas price in effect at the time of production, (b) the current market value of such gas, or (c) if a firm contract is in hand, the contract price (EITF Issue No. 90-22). An imbalance payable would be valued at the greatest of the three values.

Underproduced parties should consider the credit worthiness of overproduced owners to ensure that the carrying value of the receivable is collectible. If a portion of the receivable is not collectible, the balance should be adjusted to the amount expected to be received.

PRODUCER GAS IMBALANCES

GAS BALANCING AGREEMENTS

To reduce operational and settlement conflicts, a GBA should be included in the joint operating agreement, which is completed prior to drilling a well. If a GBA was not included in the joint operating agreement, a GBA should be negotiated as soon as possible and prior to a property's reserves becoming fully depleted. As more fully addressed in COPAS Bulletin 24, a GBA should cover the following items:

- **Balancing unit.** The GBA should address the geological formation covered and whether balancing will be computed on a mcf or mmBtu basis.
- **Rights and obligations.** The agreement should address rights and obligations of both the operator and nonoperator with respect to nominating gas, curtailments, operational issues, limitations on overproduced gas, and rights of parties in the event an overproduced working interest owner becomes bankrupt.
- **Statement of gas balancing.** The GBA should specify the content of the statement, the party responsible for its preparation, and the timing of its preparation. Normally the operator prepares the statement.
- **Ownership changes.** The agreement should address whether gas imbalances should be settled in cash when a working interest is sold or transferred to a new owner.
- **Royalty and production tax payments.** The GBA should address the responsibility of each producer for paying royalties and taxes.
- **Volumetric balancing methods.** The agreement should determine what balancing alternatives (gas make-up, exchange make-up, offsetting of imbalances) are available to volumetrically settle imbalances.
- **Cash settlement methodology.** The GBA should describe the frequency of cash settlements and the valuation methodology (actual proceeds, LIFO, FIFO, or current market value).

DETERMINING PRODUCER GAS IMBALANCES

The aforementioned monthly production volume allocation statement is the primary source of information required to compute producer balancing positions. This statement distributes the total quantity of gas produced based on the predetermined allocation methodology. Multiple allocation statements may be prepared if a well is connected to more than one pipeline. The total of the allocation statements should equal the well's or property's total production.

The producer gas imbalance is the difference between the following:

- The working interest owner's share of production on the allocation statement, and
- The working interest owner's entitled share of production, which is calculated by multiplying (1) the total volume of gas produced by (2) typically the working interest owner's gross working interest.

If the royalty interest owner takes its royalty in-kind, the working interest owner's entitled share of production is based on net revenue interest.

The operator is responsible for preparing a monthly gas balancing statement which provides each working interest owner with their cumulative over- or underproduced position. Nonoperators should test the accuracy of the gas balancing statement by verifying the accuracy of their working interest, total production amounts, and allocated share of production. All discrepancies should be communicated to the operator.

SETTLING PRODUCER GAS IMBALANCES

The operator facilitates settling producer imbalances in accordance with the terms of the GBA. In the absence of a GBA, working interest owners should determine the settlement alternatives prior to fully depleting the reserves. Gas make-up, cash balancing, and offsetting imbalances represent the three most common methods used to settle producer gas imbalances. Under the gas make-up method, the *underproduced* owner(s) will sell gas volumes in excess of their entitled amounts, and in turn the *overproduced* owner(s) will sell gas volumes less than entitled in order to eliminate the imbalance. Cash balancing involves paying a cash settlement to the underproduced party for the imbalance volume. Working interest owners may also agree to offset imbalances of two or more wells or properties in which the owners coincidentally have ownership interests.

ACCOUNTING FOR PRODUCER GAS IMBALANCES

The sales and entitlement methods represent the two methods used to account for gas sales and gas imbalances. Both of these methods are in accordance with generally accepted accounting principles and are permitted by the SEC. The *1999 PricewaterhouseCoopers Survey of U.S. Petroleum Accounting Practices* found that 51 percent and 49 percent of the survey respondents used the sales and entitlement methods, respectively.

Sales Method. Under the sales method, a WI owner records revenue only when the gas is produced and sold on the owner's behalf. For producer gas imbalances, no receivables or payables are recorded, but proved reserves are adjusted as illustrated in Figure 14-1.

When a WI owner has overproduced in excess of its share of remaining estimated reserves, the overproduced party should recognize the excessive gas imbalance as a liability on the balance sheet. When an underproduced working interest owner determines that an overproduced partner's share of remaining reserves is insufficient to settle an imbalance, the underproduced party will recognize a receivable, to the extent collectible, from the overproduced owner. Consequently, it is necessary for companies utilizing the sales method to maintain schedules that compare the cumulative over- or under-takes to the remaining reserves available to settle imbalances.

Entitlement Method. Under the entitlement method, a WI owner records revenue based on its entitled share of total monthly production. When a working interest owner is overproduced, the monthly excess of the value taken over the entitled value is recorded as a payable or as deferred revenue. The underproduced WI owner records a receivable and revenue for the monthly imbalance amount as illustrated in Figure 14-1.

Producer Imbalance Valuation and Disclosure. At the November 8, 1990, meeting of the FASB's Emerging Issues Task Force, an SEC observer stated the following:

- The SEC staff has not taken a position on whether the sales method or entitlement method is preferable;
- If the gas imbalance is significant, companies should disclose the accounting method and the imbalance volume and value; and

- Companies should disclose in the management's discussion and analysis section of their annual report the effect of gas imbalances on operations, liquidity, and capital resources (EITF Issue No. 90-22).

Additionally, companies using the sales method should adjust the standardized measure of future cash flows as well as net revenues used in the ceiling test for any imbalances impacting proved reserves.

The imbalance receivables and payables should be recorded using the amounts expected to be received or paid. The GBA may require valuing the imbalance using a LIFO, FIFO, average value received, or current market method. Absent a GBA, gas imbalances are frequently recorded at the average value received when the imbalance arose or at the current market value. Informal SEC staff interpretations have called for valuing an imbalance receivable at the lowest of (a) the gas price in effect at the time of production, (b) the current market value of such gas, or (c) if a firm contract is in hand, the contract price (EITF Issue No. 90-22). An imbalance payable would be valued at the greatest of the three values.

Depreciation, Depletion, and Amortization (DD&A). Production and estimated reserve quantities used to calculate DD&A should be based on the same method used to record revenues. Thus, an overproduced party using the sales method will have greater historical revenues and production than under the entitlement method but will also have greater DD&A. When the sales method is utilized, the total remaining reserves must be adjusted for imbalance amounts in order to properly calculate a working interest owner's share of remaining reserves.

Operating Expenses. Producers should ensure that operating expenses are recorded in a manner consistent with the method used to recognize revenue. Because working interest owners are obligated to pay for their *entitled* share of operating costs on a monthly basis, the entitlement method provides a proper matching of revenues and expenses without any adjustment of expenses.

Figure 14-1: Illustration of Sales and Entitlement Methods

A property owned 60% by A and 40% by B subject to a 20% royalty interest produces 100,000 mcf of natural gas of which 45,000 mcf is sold by A at $1.60/mcf and 55,000 mcf is sold by B at $1.50/mcf. Severance taxes are 5%. The gas imbalance is 15,000 mcf. The net revenues for the month and the corresponding balance sheet amounts at the end of the month are calculated as follows:

	Entitlement Method		Sales Method	
	A	B	A	B
Revenue Calculation				
8/8ths quantities *sold*	60,000	40,000	45,000	55,000
Less royalty share (20%)	(12,000)	(8,000)	(9,000)	(11,000)
Net quantities sold	48,000	32,000	36,000	44,000
x price	$ 1.60	$ 1.50	$ 1.60	$ 1.50
Revenue	$ 76,800	$ 48,000	$ 57,600	$66,000
Severance tax expense (5%)	(3,840)	(2,400)	(2,880)	(3,300)
Revenue net of tax	$ 72,960	$ 45,600	$ 54,720	$ 62,700
Balance Sheet Entries, Dr. (Cr.)				
Accounts receivable (8/8ths)	$ 72,000	$ 82,500	$ 72,000	$ 82,500
Royalties payable (net of tax)*	(13,680)	(15,675)	(13,680)	(15,675)
Severance tax payable (8/8ths)*	(3,600)	(4,125)	(3,600)	(4,125)
Gas imbal. receivable (payable)*	24,000	(22,500)	0	0
Less related royalties (20%)	(4,800)	4,500	0	0
Less related sev. tax (5%)	(960)	900	0	0
	$ 72,960	$ 45,600	$ 54,720	$ 62,700
Reserve Calculation				
Assume beginning 8/8ths ultimate reserves are two bcf.				
Beginning net reserves, mcf	960,000	640,000	960,000	640,000
Less entitled prod. in month 1	(48,000)	(32,000)	(48,000)	(32,000)
+/- other quantities sold	0	0	12,000	(12,000)
- Net production deemed sold	(48,000)	(32,000)	(36,000)	(44,000)
Net ending reserves	912,000	608,000	924,000	596,000
Net ending reserves if no imbalance	912,000	608,000	912,000	608,000
+/- gas imbalance not recognized as a receivable or payable	0	0	15,000	(15,000)
Less portion for royalty	0	0	(3,000)	3,000
Net ending reserves	912,000	608,000	924,000	596,000

*The *1999 PricewaterhouseCoopers Survey of U.S. Petroleum Accounting Practices* found that approximately 80% of the respondents paid royalties and severance taxes on the sales method, and 70% of those using the entitlement method booked the imbalance as a receivable or payable.

Under the sales method, a question arises as to whether operating expenses should be expensed as incurred because they relate to that month's production activity regardless of revenues recognized that month or matched with revenue consistent with DD&A expense recognition. Should an owner that is allocated no sales in a month defer revenue but not operating expenses? Should an owner allocated all sales in a month record only its entitled share of expenses for the month, whereby in a future month the owner may record no sales but will record its obligatory share of that future month's operating expenses?

Such scenarios suggest that operating expenses should be matched with revenues consistent with DD&A expense recognition.

In order to achieve a proper matching under the sales method consistent with DD&A expense recognition, operating expenses would have to be accrued or deferred, depending on whether the company is overproduced or underproduced. These accruals and deferrals would be reversed as the imbalances are settled. In practice, companies utilizing the sales method seldom accrue or defer operating expenses unless the amounts are considered material. The *1999 PricewaterhouseCoopers Survey of U.S. Petroleum Accounting Practices* found that only 12 percent of the companies using the sales method adjust operating expenses for imbalances.

Severance Taxes. State severance taxes are usually paid based on actual sales. Consequently, the sales method provides for the proper matching of revenue with severance tax expense. Under the entitlement method, additional state severance tax should be accrued or deferred if a company is under- or overproduced. These accruals and deferrals would be reversed as the imbalances are settled. In practice, companies seldom record these entries unless they are considered material.

Royalties. Companies must ensure that royalty payments are made in accordance with the applicable lease agreements and regulatory guidelines. In order to properly match the cash inflow associated with gas sales, most companies pay royalties on a sales method, regardless of the method used to recognize their share of revenue and record producer imbalances.

Chapter Fifteen

PRODUCTION COSTS

This chapter addresses both the nature of and the accounting for oil and gas *production costs,* which are also referred to as *lifting costs* or *lease operating expenses*. The classification does not customarily include depreciation, depletion, or amortization of mineral properties, wells, and related facilities and equipment. Production costs become part of the cost of oil and gas produced.

PRODUCTION COSTS DEFINED

Production costs are defined in Reg. S-X Rule 4-10(a)(17) as follows, similar to the language in Oi5.115 and Oi5.116:

> Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:
>
> (A) Cost of labor to operate the wells and related equipment and facilities.
> (B) Repairs and maintenance.
> (C) Materials, supplies, fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
> (D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
> (E) Severance taxes.
>
> …Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

ACCOUNTING FOR PRODUCTION COSTS

Production costs are expensed as incurred except in two cases:

- Recording oil and gas inventory at cost and
- Accrual or deferral of production costs associated with gas imbalances using the sales method of accounting.

Production costs theoretically are part of the cost of oil and gas produced and, therefore, allocable to inventory and cost of goods sold. However, crude oil and natural gas inventories are usually insignificant and not recognized on E&P company balance sheets. The *1999 PricewaterhouseCoopers Survey of U.S. Petroleum Accounting Practices* found that only 17 (38 percent) of 45 responding companies recorded a financial statement asset for oil inventory in the field.

As explained in Chapter Fourteen, the sales method of accounting for gas imbalances may reflect an accrual or deferral of production costs to better match expenses with revenues.

Thus, the accounting problems related to production costs concern cost control, analysis of profitability, and record keeping for tax reporting purposes.

In accounting for production costs, one of the first requirements is to determine the functional accounts that will be used. The accounting system must provide information in sufficient detail to permit the accounting for costs in accordance with recognized accounting principles and at the same time meet the needs of operating personnel in evaluating operations. In accounting for production costs, it is also essential that the accounting records furnish the necessary data for federal income tax purposes as addressed in Chapter Twenty-Six.

THE COST CENTER

For financial reporting, lease operating expenses may be aggregated by country or large geographical area. However, for management control, joint interest billings (Chapter Ten), reserve determination (Chapter Sixteen), and income tax reporting (Chapter Twenty-Six), lease operating expense records are maintained at the well and lease levels. Some costs are readily identifiable with the a well or lease, but other costs must be accumulated by classifications or functions and then apportioned to the wells or properties on some reasonable basis.

ACCUMULATION OF COSTS

In Our Oil Company, those lease operating expenses that can be closely related to the individual leases are charged directly to Account 700, Lease Operating Expenses (see Appendix 5). Indirect costs are accumulated in Accounts 350 through 369, Clearing and Apportionment accounts, and then allocated to operating expenses of individual leases. Some costs are considered indirect because of the nature of the cost item itself, while others are considered indirect as the result of the practical aspects of cost accumulation. The classification of specific costs as direct or indirect varies from company to company.

Listed below are the Appendix 5 subaccounts for Lease Operating Expenses.

Sub A/C	Sub A/C Name	Direct or Indirect
001	Salaries and Wages	Direct
002	Employee Benefits	Direct
003	Contract Pumping Services	Direct
004	Well Services and Workovers	Direct or Indirect
005	Repairs and Maintenance of Surface Equipment	Direct
006	Fuel, Water, and Lubrication	Direct
007	Supplies	Direct
008	Auto and Truck Expenses	Direct or Indirect
009	Supervision	Indirect
010	*Ad Valorem* Taxes	Direct
011	Production and Severance Taxes	Direct
012	Other Taxes	Direct
013	Compressor Rentals	Direct
014	Insurance	Direct or Indirect
015	Salt Water Disposal	Direct or Indirect
016	Treating Expenses	Direct or Indirect
017	Environment and Safety	Direct
018	Overhead	Indirect
019	Royalties (where appropriate)	Direct
020	Other	Direct or Indirect

It is obvious that the classification of costs is rather arbitrary, and in most cases, it is not immediately clear how a particular cost should be classified because the subaccounts used are a mixture of classification by *nature* (salaries, supplies, insurance) and by *function* (well service, repairs, auto and truck). Thus, each company must make arbitrary decisions. For example, in Our Oil Company, if field labor is used in well services activities, the labor cost is charged to subaccount Salaries and Wages rather than to subaccount Well Services and Workover. Other companies might make different assumptions about classifying costs. Therefore, it is important that the classification system be understood by all company personnel and followed consistently.

DIRECT PRODUCTION COSTS

Direct production costs are those costs that can be closely related to the production of oil or gas on specific mineral properties. These costs are largely controlled at the lease operating level. Several of these direct costs will be examined to illustrate both the nature of the costs involved and the manner in which they are handled for accounting purposes.

Salaries and Wages

Field employees are pumpers, gaugers, roustabouts, and other employees below first-level supervisors. They are employed directly on the oil and gas producing properties. These employees are concerned with the basic lease and facility operations and routine maintenance. Time sheets or other written documentation will customarily show the time spent on each job or each well or lease and provide the basis for charging the salaries and wages to individual properties or wells. The allocation of expenses to the individual wells or properties would normally occur during the monthly joint interest billing cycle.

Employee Benefits

Employee benefits are considered to be part of the total cost of labor and would be allocated to the individual leases. The normal practice is for the company to develop estimates of the ratio of employee benefits to direct labor costs. For purposes of simplicity, it is assumed that employee benefits for Our Oil Company were 20 percent of the direct labor costs. In Our Oil Company, charges for all employee benefits are originally recorded in Account 903, Employee Benefits. At each pay period (or monthly in some companies), an entry is made charging Lease Operating Expenses and crediting Employee Benefits for the predetermined percentage of labor costs.

Contract Pumping Services

It is common in the industry for individuals to render pumping and routine maintenance services to companies on a contract basis. The company and the individual enter into a contract whereby the individual renders certain services on specific properties for a stipulated sum that gives consideration to the number of wells, their location, the type of services to be rendered, the time schedule involved, and other factors negotiated by the parties. In this arrangement the individual is acting as an independent contractor and is not considered to be an employee of the company. The individual's charges will cover all expenses including time, vehicle usage, and travel (if any). Unusual items will be billed individually to the company for approval. The monthly invoice from the contractor should provide the details necessary for accounting entries.

Well Services and Workovers

The definition of *well services and workovers* varies. For example, some companies include such items as repairs to sucker rods, tubing, and wellhead connections in this category, while other treat those costs as repairs. Similarly, there is a question of which *workover* costs should be charged to operating expense and which should be capitalized.

In Our Oil Company, charges are made to this production expense subaccount for costs of repairing sucker rods and tubing, costs of pulling rods and tubing, repairing well head connections, swabbing, cleanout work, scraping paraffin, and replacing or servicing gas lift valves. In general, Our Oil Company charges all repairs to the wells or to equipment in the wells to this subaccount. Costs of outside services relating to the reconditioning, repairing, or reworking of a producing well are expensed to this subaccount. Similarly, the subaccount is charged for operations to restore efficient operating conditions. Costs such as reperforating casing, repairing casing leaks, or acidizing and shooting to get the well producing again are proper charges to this subaccount rather than to capital additions and improvements. Cost of workovers adding proved reserves are capitalized. Projects that call for deepening the well to another horizon or attempting to secure production from a shallower horizon (i.e., recompleting) or improving (not restoring) access to proved reserves from a producing horizon (e.g., fracing or lateral drilling) are treated as drilling costs. If the deeper drilling or the attempted recompletion at a shallower horizon involves proved reserves at that horizon, the costs are *development* costs and should be capitalized while efforts to secure production in a horizon not already proved should be treated as *exploratory* drilling costs. See the glossary definition of *workover*.

Repairs and Maintenance of Surface Equipment

Costs of repairing lease equipment, such as tank batteries, separators, flow lines, lease buildings, engines, motors, other above ground production equipment, and lease roads, are charged to this account. In general, costs related to repairs of the well or subsurface well equipment are charged to the Well Service and Workover account. When company labor is used in such operations, the labor costs are usually charged to Salaries and Wages rather than to Repairs and Maintenance.

***Ad Valorem*, Production, and Severance Taxes**

As discussed more fully in Chapter Thirteen, *ad valorem* taxes are accrued as lease operating expenses based upon some reasonable estimate of the amount which will be assessed for the current period, while production and severance taxes are recorded when the related production occurs or when the revenue on which they are based is recorded. Production taxes may be based upon the value of product being sold or based upon the volume of product sold or a combination. The following example illustrates an entry for production taxes.

Assume that Our Oil Company's share of production from the Magness lease for June 2000 is 10,000 barrels of oil, which were sold for $20.00 per barrel. Production taxes imposed by the state were six percent of the gross value. The oil purchaser makes all necessary disbursements. The entry to record these items of income and expense is as follows:

120	Accounts Rec.— Oil and Gas Sales	188,000	
710.011	LOE—Production Taxes	12,000	
	601 Crude Oil Revenue		200,000

To record production and sale of crude oil together with related taxes from the Magness lease for June 2000.

INDIRECT PRODUCTION COSTS

Indirect operating costs are all costs that are not closely related to the production of oil and gas on specific leases and are not controllable at the lease level. These indirect costs are accounted for in much the same way as overhead costs. In general, the costs of a function or activity are accumulated and then apportioned or allocated to individual properties on the basis of direct labor hours, direct labor costs, number of wells, time of equipment use, volume of service rendered, volume of production, or some other reasonable basis. Most of these costs are accumulated by Our Oil Company in the clearing and apportionment accounts (Accounts 350 through 369).

Depreciation of Support Facilities

In virtually all of the clearing and apportionment accounts, depreciation of tangible real and/or personal property is involved. While Oi5.117 specifies that, under the successful efforts method of accounting, the costs of all support equipment and facilities used in oil and gas producing activities shall be capitalized, no mention is given to the method of depreciating these costs. Accordingly, the depreciation method is left to the experience of the company. Depreciation of support equipment and facilities will usually be computed by the straight-line method or declining balance method because use of the assets involved is not related directly to the production of specific units of oil or gas revenues; therefore, the company is able to select either method of depreciation.

Salt Water Disposal

Unfortunately, salt water is also produced in varying quantities whenever oil is produced. The salt water is a waste item that must be disposed of in an environmentally safe manner. This usually requires the salt water to be gathered and reinjected back into a formation below the surface of the earth.

If only one property is served by a particular salt water disposal system, the costs can be handled as a direct cost and charged directly into lease operating expense under Account 710-014. However, if more than one lease is served by the system or systems, some means of apportioning the costs must be determined.

If the ratio of water to oil does not differ significantly among the properties served by a system, an apportionment based on the number of wells served would be appropriate. However if the oil-to-water ratio differs significantly among the properties served, a charge based on the volume of salt water handled might be appropriate.

For example, assume that the oil-to-water ratio is about the same from each well in a reservoir served by salt water disposal system 24010. Costs of operating the system for the month of June 2000 were $40,000. This system serves the Magness B lease (24007), which has two producing wells, and the Parker B (24008) and the Parker C (24009) leases, each with four producing wells. The entry to apportion these costs is as follows:

710-015	Salt Water Disposal, Lease 24007	8,000	
710-015	Salt Water Disposal, Lease 24008	16,000	
710-015	Salt Water Disposal, Lease 24009	16,000	
	352 Support Facilities Expenses		40,000

To record apportionment of the expense of salt water disposal system.

Other Apportionment Accounts

The development and use of apportionment accounts (also called clearing accounts) are similar to those discussed above. Charges accumulated in these accounts are ultimately apportioned to individual lease operating expense accounts or asset accounts. The primary problems related to apportionment accounts relate to choosing a reasonable basis for apportionment and measuring the activity related to each lease. Typical methods used to apportion costs are as follows:

- **District Expenses:** Allocated among acquisition, exploration, development, and production functions. The portion allocated to production is further allocated to individual properties on the basis of the number of producing wells.
- **Region Expenses:** Relate to operation of the regional offices and other regional activities and are initially allocated to the districts on the basis of total expenditures in each district.
- **Drilling Equipment Expenses:** Apportioned to exploratory wells or development wells on a footage rate or, in some cases, on a day-rate basis.

- **Air Compressor Plant and Systems Expenses:** Normally apportioned on a volume basis.
- **Dwelling Expenses:** An allocation in the same manner as district expenses would be appropriate.
- **Electric Power System Expense:** Power usage.
- **Fire Protection System Expense**: Number of wells or facilities in area served.
- **Gas Compressor Plant Expense:** Volumes.
- **Gas Gathering System Expense:** Volumes and/or wells served.
- **Oil Gathering System Expense:** Volumes and/or wells served.
- **Salt Water Disposal System Expense:** Volumes and/or wells served.
- **Water Flooding System Expense:** Volumes of water used.
- **Other Services Facilities Expense:** Number of hours or number of days used.
- **Transportation Equipment Expense:** Based on number of miles driven or number of hours used.
- **Warehouse and Shop Expense:** Number of items issued, cost of items issued, or direct labor hours for each lease.

The essential factor to be considered in the use of clearing or apportionment accounts is arriving at a reasonable basis for charging costs to the activities using the services involved.

PRODUCTION COSTS STATEMENTS

Production costs statements, or *lease operating statements*, are prepared monthly for each well, lease, or property. Since the individual property is often used as the cost center for successful efforts accounting, these statements are somewhat analogous to an income statement for a property. Some companies' statements include revenue from production, while others show expenses only. The entity's share of revenue and its share of operating expenses are shown. Details of all items are indicated and usually are shown for the current month and the year-to-date. Additional information or changes in format will depend upon each entity. For Our Oil Company, a portion of the Lease Operating Statement for Lease No. 24001 (having a one-eighth royalty) is shown in Figure 15-1.

Figure 15-1: Lease Operating Statement

Our Oil Company			Lease: Mag #24001	
LEASE OPERATING STATEMENT			WI: 60.0%	
1999			NRI: 52.5%	
	January	February		Year To Date
8/8ths Volumes Sold:				
Oil bbls	315	312	*Ten more*	3,600
Gas mcf	1,200	1,150	*monthly*	12,000
NGL bbls	0	0	*columns*	0
			exist on a	
OOC's Sales Prices:			*standard*	
Oil $/bbl	$20.25	$20.45	*lease*	$21.00
Gas $/mcf	$2.71	$2.95	*operating*	$2.65
NGL $/bbl	$0.00	$0.00	*statement.*	$0.00
Per BOE at 6 mcf: 1bbl	$18.70	$19.40		$19.18
Revenues @ 8/8ths:				
Oil	$6,379	$6,380		$75,600
Gas	3,252	3,393		31,800
NGL	0	0		0
Total revenues	9,631	9,773		107,400
Less Royalties & ORRIs	(1,204)	(1,222)		(13,425)
WI Revenues @ 100%	8,427	8,551		93,975
WI Expenses @ 100%:				
001 Salaries & wages	0	0		0
002 Employee benefits	0	0		0
003 Contract pumping	250	250		3,000
etc., by subaccounts	400	755		5,800
018 Overhead	200	200		2,448
020 Other expenses	0	0		0
Total expenses	850	1,205		11,248
WI Net Cash Flow @ 100%	$7,577	$7,346		$82,727
OOC's Share:				
Revenue	$5,056	$5,131		$56,385
Expenses	(510)	(723)		(6,749)
Cash flow	$4,546	$4,408		$49,636
Revenue per boe	$18.70	$19.40		$19.18
Expenses per boe	(1.89)	(2.73)		(2.30)
Cash flow per boe	$16.81	$16.67		$16.88

Chapter Sixteen

OIL AND GAS RESERVES

INTRODUCTION

Proved reserves are fundamental to E&P financial reporting:

- Capitalized costs of proved properties are amortized on a units-of-production method based on the ratio of volumes currently produced to the sum of those volumes and remaining proved reserves (Chapter Seventeen);
- Proved properties' net capitalized costs are limited to certain computations of value of the underlying reserves (Chapters Eighteen and Nineteen);
- Proved reserve estimates impact the timing for expensing field remediation and abandonment costs (Chapter Twenty-One);
- Proved reserves are used in determining whether and to what extent gain is recognized in certain conveyances of oil and gas property (Chapters Twenty-Two through Twenty-Four); and
- Public companies must disclose certain supplemental unaudited information on the proved reserve volumes (Chapter Twenty-Nine) and certain values attributable to the proved reserves (Chapter Thirty) with audited financial statements.

Chapter Sixteen defines reserves and key reserve categories and provides an overview of how reserves are estimated and reported. The focus is on proved reserves as the category fundamental to financial accounting and reporting.

GENERAL DEFINITIONS AND CATEGORIES

Reserves are a category of *oil and gas resources*. Reserves are estimates usually made by petroleum reservoir engineers, sometimes by geologists but, as a rule, not by accountants. The Society of Petroleum Evaluation Engineers' Monograph I, *Guidelines for Application of the*

Definitions for Oil and Gas Reserves, provides the following categories of oil and gas resources:[49]

- Total Oil and Gas Resources
  1. Undiscovered
  2. Discovered
     a. Nonrecoverable resources
     b. Recoverable resources (or ultimate reserves)
        i) Cumulative past production
        ii) Reserves
           • Proved reserves
              · Proved developed
                 —Proved developed producing
                 —Proved developed nonproducing
                    - Behind-pipe reserves
                    - Shut-in reserves
              · Proved undeveloped
           • Unproved reserves
              · Probable reserves
              · Possible reserves

Resources refer to estimated volumes of oil and gas that have been produced and volumes that are physically in the ground but may or may not be presently known or economically recoverable. Total world oil resources are estimated to be nine trillion barrels, over 300 times the world's current annual oil production.[50]

Discovered resources are those estimated volumes contained in known petroleum reservoirs. Discovered oil resources are largely unrecoverable under current economics and technology. It is not uncommon for more than half the discovered oil in a reservoir to be economically unrecoverable, whereas the recoverability of a reservoir's natural gas can often exceed 70 percent.

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[49] *Guidelines for Application of the Definitions for Oil and Gas Reserves*, a December 1988 monograph by the Reserves Definition Committee of the Society of Petroleum Evaluation Engineers.

[50] Estimated world oil resources appears in John L. Kennedy's paper, "Oil and Gas Markets, Companies, and Technology in the 1990's and Beyond", in the *Journal of Petroleum Technology,* August 1995.

The term *discovered recoverable resources* refers to petroleum already produced as well as reserves, i.e., estimated future production. The world's discovered oil resources recoverable with a high degree of certainty consist of approximately 850 billion barrels of past recorded world oil production through 1999 and approximately one trillion barrels of proved oil reserves—20 percent of world resources.[51]

The Society of Petroleum Engineers (SPE) and the World Petroleum Congress (WPC) approved in March 1997 definitions of *reserves* and several categories of reserves (SPE/WPC reserve definitions). In 1998 the Society of Petroleum Evaluation Engineers approved the SPE/WPC reserve definitions. *Reserves* of oil and gas were defined as

> quantities of petroleum which are anticipated to be commercially recovered from known accumulations from a given date forward. All reserve estimates involve some degree of uncertainty. The relative degree of uncertainty may be conveyed by placing reserves into one of two principal classifications, either proved or unproved.

Two significant attributes of the SPE/WPC definitions are (1) acceptance by two large and well-respected industry organizations and (2) inclusion of deterministic and probabilistic methods for expressing reserve estimates. The method is *deterministic* if a single best estimate of reserves is made based on known geological, engineering, and economic data. The method is called *probabilistic* when the known geological, engineering, and economic data are used to generate a range of estimates and their associated probabilities. Before addressing the various categories of reserves, several points should be noted.

- Financial reporting uses a definition of proved reserves adopted by the SEC in 1978 that is generally, but not entirely, consistent with the SPE/WPC definitions of reserves and proved reserves, as addressed later in this chapter.
- Reserves are expressed in volumes rather than in dollars or energy content. Some definitions refer to *quantities* rather than volumes and recognize that reserves may be expressed by weight (e.g., metric tons of oil) or energy content (e.g., mmBtu of gas).

[51] Primary source: "The State of the Global E&P Industry: Is the World Running Out of Oil," Society of Petroleum Engineers paper no. 56456, presented in October 1999.

- The amounts of reserves and *recoverable* resources change as economic factors change. In general, if the price of oil goes up faster than production costs, more oil can be commercially recovered, and reserves will increase. If oil price declines, reserves typically decline. On the other hand, resource estimates refer to volumes physically present that do not change with petroleum prices.
- Reserves are "as of" a given date, e.g., as of December 31, 1999 (and not for the year ended December 31, 1999). The *as of* date should be included when reporting a reserve estimate.
- The terms *estimated reserves, reserve quantities,* and *remaining reserves* are inherently redundant, since reserves are estimated remaining volumes, but such terms are commonly used and generally acceptable in emphasizing key characteristics of reserves.
- The reliability of reserve estimates is subject to the reliability of available underlying geologic and engineering data and experience, expertise, and judgment of the estimator.
- All reserve estimates reflect some degree of uncertainty.

Within the SPE/WPC definitions, *proved reserves* are

> those quantities of petroleum, which by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations. . . . If deterministic methods are used, the term reasonable certainty is intended to express a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate.

Subclassifications of proved reserves will be addressed more thoroughly in sections discussing SEC reserve definitions later in this chapter. These classifications include *proved developed producing reserves*, *proved non-producing reserves*, and *proved undeveloped reserves*. SEC definitions should always be used for financial reporting.

Unproved reserves are reserves

> based on geologic and/or engineering data similar to that used in estimates of proved reserves; but technical, contractual, economic, or regulatory uncertainties preclude such reserves being classified as

> proved. Unproved reserves may be further classified as probable and possible reserves.

Unproved reserves are not reported to the SEC or used for financial accounting purposes, such as calculating DD&A or ceiling tests. However, risk-adjusted unproved reserves, particularly probable reserves, may be used in developing expected cash flows and fair values pursuant to FAS 121 on accounting for impairment of long-lived assets (Chapter Eighteen).

Probable reserves are

> those unproved reserves which analysis of geological and engineering data suggest are more likely than not to be recoverable. In this context, when probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will be equal or exceed the sum of estimated proved plus probable reserves.

Normally, *probable reserves* refer to additional reserves that will likely become proven with additional drilling or with the successful testing (or implementation) of a new enhanced recovery project. *Probable reserves* can also refer to incremental reserves not recoverable under existing economic conditions but recoverable based on expected favorable changes in economic conditions.

Possible reserves are those unproved reserves

> which analysis of geological and engineering data suggests are less likely to be recoverable than probable reserves. In this context, when probabilistic methods are used, there should be at least a 10% probability that the quantities actually recovered will equal or exceed the sum of estimated proved plus probable plus possible reserves.

PROVED RESERVE CLASSIFICATIONS

This chapter section focuses on the SEC definitions of *proved*, *proved developed*, and *proved undeveloped reserves*. FAS 25, Paragraph 7, provides that for FAS 19 and FAS 25, such SEC definitions shall apply that are in effect on the date(s) as of which reserve disclosures are to be made. Thus, as the SEC changes its definitions, the applicable FAS definitions will automatically change to match the current SEC definitions.

PROVED RESERVES

Reg. S-X Rule 4-10(a)(2) defines *proved oil and gas reserves* as

> the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions. . . .

Based on observed practices and the authors' experiences, the following observations and examples for proved reserves as of December 31 illustrate how to apply the phrase "existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made:"

- The phrase *the date the estimate is made* refers to the "as of" date of December 31 and not when the December 31 reserve estimate is made, which might be several weeks before or after the as-of date. If the December 31 proved oil reserves were estimated in early December, based on a November 30 spot price of $25 per barrel, but the price at December 31 is $22 per barrel, then the estimate should in theory be revised to reflect December 31 pricing even if by mid-January of the following year the price had recovered to $25 per barrel.[52]
- Reserves should reflect oil, gas, and NGL spot prices at December 31 except to the extent of pricing determinable under sales contracts existing at December 31. For example, assume for a given field, the December 31 spot price is $2.80/mmBtu. Assume a contract in December calls for the sale of 1 bcf of gas from the field in the subsequent calendar year at a price of $3.00 per mmBtu while a second contract calls for the sale of 2 bcf of gas at 5 cents over index prices. The $3.00 determinable price is used for 1 bcf of reserves to be produced in the subsequent year. All other gas is priced at the $2.80

[52] An exception to this rule is found in applying the full cost ceiling test, as more fully described in Chapter Nineteen. The ceiling for capitalized costs may reflect higher oil and gas prices occurring after the balance sheet date.

spot price (consistent with SAB Topic 12A, Item 2, Question 1). The contract price based on index pricing is not fixed and determinable at December 31.

- Absent fixed and determinable contract prices, the oil, gas, and NGL market (spot) prices on December 31 should be used even though such prices may be materially higher or lower than the actual realized prices for December or January. Historically many companies have used the December average actual prices received when such prices are close approximations of the month-end prices. However, as more fully explained in Chapter Twenty-Nine, the SEC staff issued on the SEC website an interpretation that average prices for any period was not a suitable proxy for the "year-end" price required by SFAS 69 for the standardized measure. SAB Topic 12A, Item 2, Questions 1 and 2, calls for determining year-end reserves by using "current market prices" at year-end. Hence, the SEC staff will object to average prices or any pricing that does not reflect the year-end spot price, unless such pricing reflects firm contracts with determinable prices.
- U.S. natural gas spot prices are volatile. Consequently, the average annual gas prices are often used in forecasting future cash flow for valuation of gas fields. However, the average annual gas price is not used for determining proved reserves under the SEC definition. SEC rules require the use of December 31 spot price for calendar-year financials despite the caveat found in SAB Topic 12A, Item 2, Question 2, to use the year-end price "provided the company can reasonably expect to sell the gas at the prevailing market price."
- Production tax and severance tax rates should reflect laws enacted as of December 31 (and not enacted in the following January). So for an October 1999 state law raising the tax rate from five percent to six percent effective January 1, 2000, the rate would be six percent for estimating the proved reserves recoverable under December 31, 1999, economic conditions.
- Future operating costs should reflect rates as of December 31 applied to expected operations, such as periodic workovers or additional gas compressors.

The SEC definition continues:

> Reservoirs are considered proved if economic productivity is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (a) that portion delineated by drilling and defined by gas-oil or oil-water contacts, if any, and (b) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir [see Figure 16-1].
>
> Reservoirs that can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the proved classification if successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.
>
> Estimates of proved reserves do not include the following: (A) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves"; (B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects; and (D) crude oil, natural gas, and natural gas liquids that may be recovered from oil shales, coal, gilsonite, and other such sources.

PROVED DEVELOPED AND UNDEVELOPED RESERVES

The same Reg. S-X Rule 4-10(a)(2) defines *proved developed reserves* as

> reserves that can be expected to be recovered through existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural gas forces and mechanisms of primary recovery should be included as proved developed reserves only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

Reg. S-X Rule 4-10(a)(4) defines *proved undeveloped reserves* as

> reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells for which a relatively major expenditure is required for recompletion. Reserves on undrilled acreage should be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only if it can be demonstrated with certainty that there is continuity of production from the existing productive formation [see Figure 16-1]. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

The SEC reserve definitions for proved developed and proved undeveloped reserves specifically state that estimated quantities of oil expected to be obtained through application of fluid injection or other improved recovery techniques are proved only if testing or operations have been successful in the same (pressure-connected) reservoir. The SPE/WPC definition requires only that such testing or operations have been successful in a reservoir in the immediate area with similar rock and fluid properties. This is the most significant difference between the SEC definitions and the SPE/WPC definitions.

The SEC reserve definitions are augmented by SAB Topic 12 presented in Appendix 2 of this book. Two points of Topic 12 are as follows:

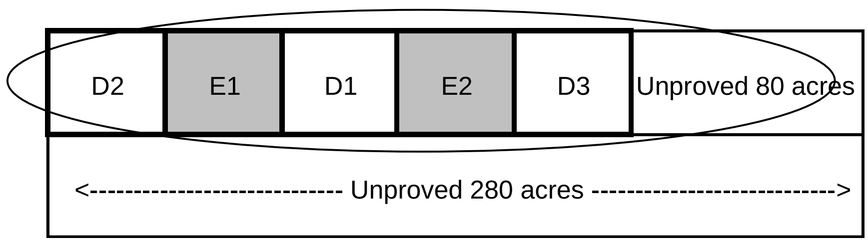
- Net natural gas liquids reserves are related to the leasehold in which ownership is held and not to NGLs received for operating or owning the gas processing plant at which the NGLs were recovered (SAB Topic 12A, Item 1 on page App. 2-2).
- Coalbed methane is not *gas derived from coal* and should be included in proved gas reserves (SAB Topic 12G on page App. 2-19).

Additional guidance in estimating reserves is found in the latest edition of the SPEE monograph on reserve definitions.

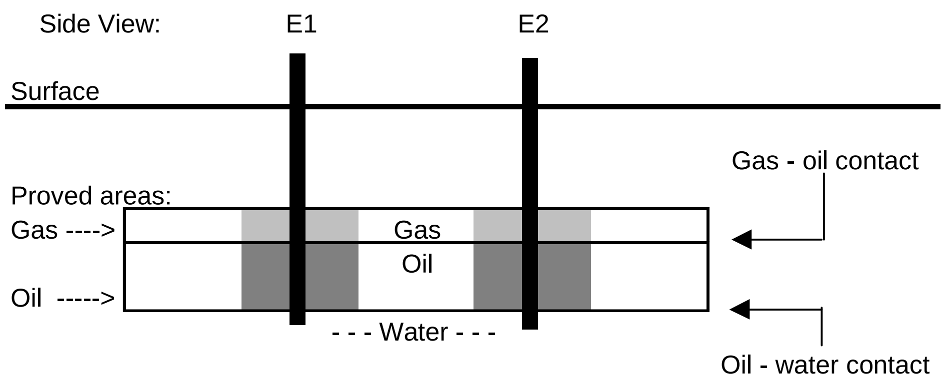
Figure 16-1: Illustrative Proved Areas of a Reservoir

Two exploratory wells E1 and E2, drilled on 40-acre spacing, have proved reserves. Earlier G&G studies showed the producing structure to be a narrow ellipse, so only three offset locations are proved (D1, D2, and D3). The total proved area is 200 acres consisting of five drill spacing units on a 560 acre lease.

Top View:



Side View:



If the gas-oil and oil-water contacts are ten feet apart, then the 200-acre proved portion of the oil reservoir has ten feet of "pay" and a volume of 2,000 acre-feet. If such volume is 90% rock, 2% water, 5% unrecoverable oil and 3% recoverable oil (with 7.758 barrels in an acre-foot), then the proved oil reserves approximate 465,000 barrels [i.e., 2,000 x 3% x 7,758]. Fluid properties could be used to estimate the change in volume as the oil moves from reservoir temperature and pressure to the surface.

SUBCATEGORIES OF PROVED DEVELOPED RESERVES

Proved developed producing reserves are expected to be recovered from completion intervals producing at the time of the estimate.

Proved developed nonproducing reserves are of two types—*shut-in* and *behind-pipe* reserves. *Shut-in reserves* are those reserves expected to be recovered from completion intervals that were open at the time of the reserve estimate but were not producing for generally one of three reasons:

- The well was intentionally shut in for market conditions, such as a perceived temporary decline in oil or gas prices;
- The well had not yet begun production from the completed interval (perhaps because production equipment or pipelines were not yet installed); or
- Mechanical difficulties have not yet been corrected.

Behind-pipe reserves are those reserves expected to be recovered from completion interval(s) not yet open but still behind casing in existing wells. Such wells are usually producing, but from another completion interval. Additional completion work is needed before behind-pipe reserves are produced. Such production is usually delayed until the currently producing zone is depleted. A requirement for behind-pipe reserves being considered developed is that they can be produced without very large capital expenditures relative to the cost of drilling another well. If the capital costs are very large, these reserves must be called proved undeveloped reserves.

RESERVE ESTIMATION

Reserve estimation is a complex, imprecise process requiring a synthesis of diverse data about the geologic environment, the reservoir rock structure and other characteristics, and the engineering analyses of the interrelationships among reservoir fluids, pressure, temperature, operating practices, markets, prices, and operating costs. In estimating reserves, the engineer's judgments are influenced by existing knowledge and technology, economic conditions, applicable statutory and regulatory provisions, and the purposes for which the reserve information is to be used. As an oil and gas field is developed and produced, more geological and engineering data become available for estimating the reserves.

GENERAL ESTIMATION METHODS

In addition to the deterministic and probabilistic methods of expressing reserve estimates, there are four common methods of estimating reserves:

1. Analogy,
2. Volumetrics,
3. Performance curves, and
4. Material balance analysis.

Analogy

Analogy employs experience and judgment to estimate reserves based on observations of similar situations (e.g., nearby producing wells) and includes consideration of hypothetical performance. Analogy is used when data are unreliable (exploration plays) and/or insufficient to warrant the use of other estimating methods. For example, possible reserves for a proposed well are estimated to be 500,000 barrels by analogy to similar nearby producing wells known to have average estimated ultimate cumulative production of 500,000 barrels. Analogy alone is generally considered to have a low degree of accuracy relative to other methods. However, any reserve estimation method employs some degree of analogy in application.

Volumetrics

The volumetric method begins with estimates of physical measurements of rock and fluid properties to determine the probable volume of hydrocarbons initially contained in a reservoir and then estimates the quantities that can be economically recovered. The percentage of original oil in place that is typically expected to be recovered can vary from 10 percent to 50 percent depending on rock and fluid properties, whereas recovery factors for gas often vary between 50 percent and 90 percent. This method is most commonly used in newly developed and/or nonpressure-depleting reservoirs (water-drive). The volumetric method has a low degree of accuracy in general, although accuracy can be greatly increased in cases of good rock quality, well control, and uncomplicated reservoirs. Figure 16-1 provides a simple example of the volumetric method of estimating reserves.

Performance Curves

For many properties, oil and gas production rates and reservoir pressures decline in patterns or *curves* that can be extrapolated to estimate future production. Figure 16-2 shows a graph with a production decline curve for a property producing for five years. Historical production for the five years is plotted on the graph to reveal a trend in the production rate over time. This trend or curve is extrapolated five years into the future to provide an estimate of future production. The engineer ends the curve extrapolation and future production when the production rate declines to the property's economic limit. This limit occurs when production is too low to provide monthly cash inflow from production sales in excess of monthly cash outflow for operating costs.

Computer programs are often used to calculate recoverable reserves from input such as the current production rate, the estimated decline, and the various economic parameters, such as operating expenses and product prices that determine the economic limit.

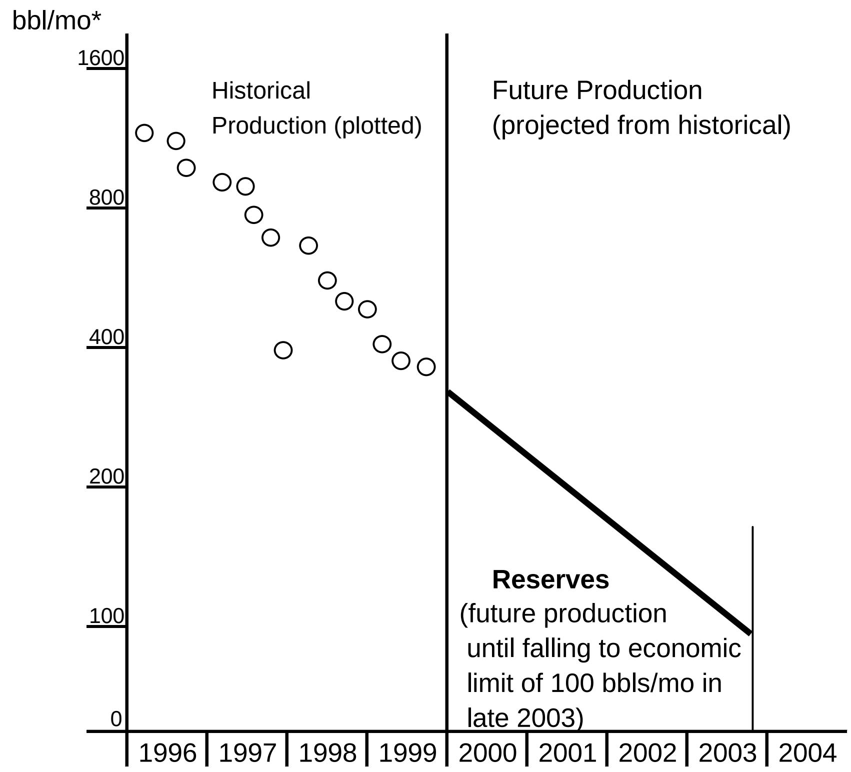
Performance curves are generally considered to provide more precise estimates than the volumetric method or analogy and are the most commonly used estimation tools after production is established. The accuracy of such curves generally improves as historical production data accumulate. Analysis of decline curves plotting the log of producing rates versus time requires special attention when wells are not producing at capacity, when the number of producing wells is changing, when operating practices change, or when completion zones are not consistent over time. Reasons for wells not producing at capacity include seasonal curtailments, regulatory prorationing, and operational problems.

Production declines in generally one of two patterns:

1. An *exponential decline curve*, whereby the percentage decline per year is relatively constant, such as ten percent decline per year, or
2. A *hyperbolical decline curve*, whereby the percentage decline per year decreases over the well's productive life.

When production is plotted on a logarithmic scale, the exponential decline is a straight line, as in Figure 16-2, whereas the hyperbolic decline curve drops steeply with initial production and curves or *flattens* to an almost horizontal line. The historical production pattern and analogy with older wells in the same or similar reservoirs will indicate which curve is applicable and the likely annual decline rate(s).

Figure 16-2: Production Decline Graph



* Production is usually expressed on a logarithmic scale for graphing.

Material Balance Analysis

This method involves complex calculations based on analysis of the relationship of production and pressure on performance, whereby reservoir pressure declines as more fluid (oil, gas, and water) is removed from the reservoir. Essentially, *material balance* simply means that the mass of all material (oil, gas, water) removed must equal *initial material* less the *material remaining*. From this simple equation, more complex relationships are developed based on reliable pressure and temperature data, production data, fluid analysis, and knowledge of the reservoir characteristics. This method's accuracy is directly related to the quantity and quality of such data, and obtaining the data necessary to justify such a detailed study can be relatively expensive.

One variation of this method generates a *p/z curve*, whereby a gas reservoir's pressure (p) divided by a gas compressibility factor (z) provides a p/z amount that declines in a pattern as the reservoir produces. By extrapolating this pattern or curve, total cumulative gas production and gas reserves can be reasonably estimated. This method requires shutting in wells for perhaps several days at a time to periodically measure pressure at the bottom of the well. Analysis of curves showing declining reservoir pressure versus cumulative production requires special attention if wells are not properly tested, if several wells produce from the same reservoir, if the reservoir had greater than normal original pressure, or if the reservoir is suspected of having a water drive (as opposed to pressure depletion). Failure to provide the required special attention when such conditions are present will generally result in estimates that are unreasonably high.

SUPPORTING DATA

In addition to the geologic and engineering data referred to above, other important data for determining reserve quantities are as follows:

1. **Records of Production.** These are records of historical daily production (as opposed to sales) that are kept in the production files and updated periodically by engineering assistants. These files should be kept for both operated and nonoperated properties. From these figures, the engineers can establish a production decline curve to determine the remaining recoverable reserves.

2. **Records of Ownership.** For ownership interests (both before and after payout), only the entity's net share of reserves is reported. These interests should come from the lease records department and should agree with the interests being used for revenue and joint interest billing. Ownership interests may change over time based on agreements among the owners. Such changes typically occur when all well costs have been recovered and are referred to as *before payout* and *after payout* interests.

3. **Records of Gas Imbalances.** Imbalances occur when owners of production do not sell quantities in proportion to their ownership

interest. Companies can choose to account for imbalances by the sales method or the entitlements methods, as explained in Chapter Fourteen. Those companies using the sales method will adjust reserves for the amount of any imbalance. A company using the entitlements method will reflect the imbalance on the balance sheet but will not adjust reserves.

4. **Records to Determine Current Pricing and Operating Costs.** For proved reserves that are by definition based on current economic and operating conditions, the engineer uses current prices and operating costs to determine the economic limit. Lease operating costs are usually available from lease operating statements but require analysis to identify recurring costs, repairs, and maintenance. A thorough analysis is necessary to identify fixed and variable portion. This analysis will be useful in projecting costs in the later years of a field as the number of wells and the daily producing rates decline.

RESERVE SCHEDULES

Reserve estimation normally includes developing schedules of how the reserves will be produced over time. Timing of production may be impacted by market conditions, by producer decisions, or by timing of investments to develop proved undeveloped reserves. Both historical conditions and future plans may be important in making reasonable projections. Figure 16-3 provides a simplistic production schedule of proved reserves.

Figure 16-4 shows a simplistic future cash flow estimate for a ten percent net revenue interest in the gross reserves of Figure 16-3. There may be schedules for each well, for each field, for each state, for each country, and even for each reserve classification, such as proved developed.

Figure 16-3: Simplistic Reserve Production Schedule

(as of 12/31/99, assuming 10% annual decline in the well's production rate)

	Oil (bbl)
Past:	
1995	10,000
1996	9,000
1997	8,100
1998	7,290
1999	6,561
Cumulative to 12/31/99	40,951
Future:	
2000	5,904
2001	5,314
2002	4,782
2003	4,304
2004	3,874
2005	3,486
Reserves at 12/31/99	27,664
Estimated Ultimate Recovery	68,615

Figure 16-4: Simplistic Schedule of Estimated Future Cash Flow from Production

Year	Gross Oil	Net Oil	Revenue	Operating Costs	Net Cash Flow	Cash Flow Discounted at 10%
2000	5,904	590	$11,800	$ 7,000	$ 4,800	$ 4,577
2001	5,314	531	10,620	7,000	3,620	3,138
2002	4,782	478	9,560	7,000	2,560	2,017
2003	4,304	430	8,600	7,000	1,600	1,146
2004	3,874	387	7,740	7,000	740	482
2005	3,486	349	6,980	7,000	(20)	(12)
Total	27,664	2,765	$55,300	$42,000	$13,300	$11,348

Reserve schedules generally show much more information than in Figures 16-3 and 16-4:

- Production and cash flow in columnar form for each year (for 10 to 20 years) and in total are presented.
- Production columns usually include gross production (oil, gas, and NGL) as well as the owner's share, or *net production*, of oil, gas, and NGL.
- Cash flow columns might include oil price, gas price, combined revenue, severance taxes, lease operating costs, net operating cash flow, investments, net cash flow, and net cash flow discounted to a present value.

The schedules may also contain estimates of federal income taxes and after-tax cash flow, both undiscounted and discounted.

RESERVE REPORTS

Reserve reports may be prepared by company employees or by independent third-party engineering firms. A discussion with the engineer is always advisable to get a better understanding of how the work was performed and the engineer's assessment of the data used.

Reserve reports are often prepared to meet the disclosure requirements of the SEC and for many other uses of interest to accountants, including the following:

- for use in historical financial reporting and income tax reporting to determine amortization of certain costs;
- for determining FAS 121 impairment of proved property (Chapter Eighteen) and for calculating the full cost ceiling test (Chapter Nineteen);
- for developing long-range plans and budgets;
- for management use in choosing among options for field development and reservoir management;
- for bank loans and lines of credit collateralized by future production,
- for valuing developed oil and gas properties, or an entire company being considered for acquisition or divestment; and
- for use in regulatory hearings or litigation.

The different purposes may require different definitions, assumptions, and methods, which may lead to very different results, and yet each may be a perfectly correct and valid report for its purpose.

In all cases the report should include a letter stating, among other things, who requested the report, the report's purpose, the effective date, a description of the properties evaluated, sources of data, significant assumptions, reserve definitions used in preparing the report, summary results, whether or not the evaluator is independent, and what definition of proved reserves was used (such as the SEC definition required for financial reporting). The letter will normally contain statements of the estimator's limited responsibility for the accuracy of the data provided to the estimator and the imprecise nature of the estimates. If the estimator is a registered professional engineer, the estimator's seal will usually be affixed to the letter.

The report may include summary reserve schedules and schedules by property. One such summary may list all properties ranked according to total present value to show the most valuable first. The report may include graphs of production decline curves and p/z curves as well as maps showing the location of existing wells and proved undeveloped locations.

Financial auditors read reserve reports and their cover letters to assist in compliance with AU 336 on use of a specialist and AU 558 and Interpretation 9558 on supplementary information. The cover letter provides much of the information needed for such compliance and may indicate areas that need to be investigated more thoroughly. For instance, a letter may reveal inconsistencies in the assumptions or methods used, such as the use of prices other than market prices at the reserve estimation date.

SPE STANDARDS FOR ESTIMATING AND AUDITING RESERVES

In 1979, the SPE developed standards for estimating and auditing oil and gas reserve information (SPE Standards). The SPE Standards are not binding on petroleum engineers but do provide estimation and reporting guidance. Many petroleum engineering consulting firms do not issue reserve estimation reports that purport to comply with the SPE Standards, since compliance is not mandatory and purported compliance would expose the firms to unnecessary legal exposure.

The SPE Standards introduced guidance for engineers on reserves estimated by another party. The SPE audit arose from FAS 19 and SEC rules proposed in 1977 and 1978 (and abandoned in late 1979) requiring disclosed proved reserves to be audited, i.e., within the audited financial statement notes. The engineer’s audit under the SPE standards was designed to be a partial audit to be completed by the independent financial auditors. The reserve engineer was to *audit* the reserve estimation process without independently verifying underlying data such as ownership interests, oil and gas prices, and operating cost rates. The engineer's report was to be addressed to the client and the client's financial statement auditors. In order to *complete* the reserve audit and to allow the reserve information to be included in the audited financial statements' footnotes, the financial statement auditors were to test the accuracy and completeness of the underlying data not verified by the reserve auditor.

The FASB and SEC do not require reserve data to be included in audited footnotes to the financial statements, only as *unaudited* supplemental information (as explained in Chapters Twenty-Eight and Twenty-Nine). However, the reserve *audit* is a popular service offered by independent petroleum engineering firms, because it is sometimes less expensive than an independent reserve determination. Reserves audited by an independent petroleum engineering firm, but not by the financial statement auditors, still appear in the *unaudited* information supplementing audited financial statements.

Unlike an audit report under AICPA standards, a petroleum engineer's reserve *audit* report can express positive assurance without the engineer testing or verifying the accuracy and completeness of the underlying data used to develop the reserve estimates. However, the engineer's reserve audit report discloses the lack of such testing or verification.

The SPE Standards are reproduced as Appendix B in the AICPA Audit and Accounting Guide, *Audits of Entities with Oil and Gas Producing Activities*.

Chapter Seventeen

DEPRECIATION, DEPLETION, AND AMORTIZATION (DD&A) UNDER THE SUCCESSFUL EFFORTS METHOD

Capitalized proved property costs are expensed as depreciation, depletion, and amortization (DD&A) as the proved oil and gas reserves to which they relate are produced. In this chapter the term *amortization* is used as a generic term to encompass all three types of periodic transfers of asset cost to expense.

This chapter focuses on DD&A under the successful efforts method of accounting. Chapter Nineteen addresses DD&A using the full cost method.

GENERAL PRINCIPLES OF AMORTIZATION

THE REQUIREMENTS OF Oi5

Both proved property acquisition costs and proved property well and development costs are to be amortized on a unit-of-production basis as the related proved reserves are produced.

Proved property acquisition costs are depleted (or amortized) over *total* proved reserves. However, costs of wells and related equipment and facilities are depreciated (or amortized) over the life of proved *developed* reserves that can be produced from assets represented by those capitalized costs. If a property is fully developed, the proved reserves and proved developed reserves should be the same. However, if a property is only partially developed, proved developed reserves will be only a part of total proved reserves.

Depreciation, depletion, and amortization may be computed separately for each individual property; alternatively, properties may be aggregated on the basis of a common geological structural feature or stratigraphic condition (for example, a reservoir or a field). In some cases, as addressed later in this chapter, royalty interests and other nonoperating interests may be aggregated without regard to geological features.

If both oil and gas are found on a property or a group of properties, the amortization per unit should normally be calculated on the basis of estimated total equivalent units (based on energy content) of oil and gas reserves. The unit-of-production rates are revised whenever the need is indicated but must be reviewed at least once each year and revised if appropriate.

THE UNIT-OF-PRODUCTION CONCEPT ILLUSTRATED

The basic computation of unit-of-production amortization is expressed by either of the following essentially identical formulas:

$$\frac{\text{Unamortized Costs at End of Period}}{\text{Reserves at Beginning of Period}} \times \text{Production for Period}$$

or

$$\frac{\text{Production for the Period}}{\text{Reserves at Beginning of Period}} \times \text{Unamortized Costs at End of Period}$$

More encompassing formulas are presented later.

To illustrate the general computation, assume the following data available at the end of an accounting period:

Capitalized costs, end of period	$1,000,000
Amortization taken in prior periods	$ 250,000
Estimated reserves at beginning of period	1,000,000 bbls
Production during period	40,000 bbls

Amortization for the period would thus be $30,000.

$$\frac{\$1{,}000{,}000 - \$250{,}000}{1{,}000{,}000 \text{ bbls}} \times 40{,}000 \text{ bbls} = \$30{,}000$$

REVISION OF ESTIMATES

Oi5.121 requires that amortization rates and reserve estimates be revised when a need for revision is indicated but at least annually. Changes in reserve estimates should be considered on a prospective basis, as required by APB Opinion No. 20. That is, a change in the estimate affects the current and future periods, but no adjustment is made in the accumulated amortization applicable to prior periods. (The problem this creates in computing amortization for *interim periods* is examined later in this chapter.) Thus, the following formula is commonly used for computing periodic unit-of-production amortization:

$$\frac{CC - AA}{EREP + CPP} \quad x \quad CPP$$

where,

CC is total capitalized costs,
AA is accumulated amortization,
EREP is estimated reserves at the end of the current period, and
CPP is the current period's production.

To illustrate this computation, assume the following facts, which are identical to those in the preceding example except that the estimate of reserves was revised during the period.

Capitalized costs, end of period	$1,000,000
Amortization taken in prior periods	$ 250,000
Estimated reserves at beginning of period	1,000,000 bbls
Production during period	40,000 bbls
Estimated reserves at the end of period	560,000 bbls

In calculating amortization for the period, the estimate of reserves originally made at the beginning of the period is ignored. Thus, even though the expected amortization at the beginning of the period was $.75 per barrel ($750,000 divided by 1,000,000 bbls), this fact is ignored in the computation, and amortization for the period is based on the revised estimate of beginning-of-period reserves. The appropriate beginning figure is the total of the revised estimate at the end of the period added to the production during the period. Based on the above facts, amortization for the period is $50,000:

$$\frac{\$1,000,000 - \$250,000}{(560,000 \text{ bbls} + 40,000 \text{ bbls})} \quad x \;\; 40,000 \; = \; \$50,000$$

GROUPINGS OF PROPERTIES FOR AMORTIZATION PURPOSES

It has been noted previously that proved properties in a common geological structure may be combined for the purpose of computing DD&A. Oi5.121 makes it clear that only properties that are closely related geologically may be combined for amortization purposes. It is not appropriate to consider a large geological unit, such as a *basin* or a *trend*, as a geological phenomenon that justifies combining properties for DD&A purposes.

As a general rule, the cost center is either the property or a property aggregation by field. Combining properties by well is often impossible, since a property often encompasses acreage greater than the well's spacing unit. In such cases, a cost center by well would not be an aggregation of properties but a portion of a property—a concept inconsistent with FAS 19 successful efforts accounting. Given five options for determining amortization cost centers, the 36 successful efforts respondents to the *1999 PricewaterhouseCoopers Survey of U.S. Petroleum Accounting Practices* generally amortized by field:

58%	by field
13	by property
11	by well
5	by reservoir
13	by *other* methods
100%	

To illustrate the grouping of proved properties, assume that four leases overlying a reservoir are drilled and developed in the current period. Data relating to the four leases follow:

	Lease				
	A	B	C	D	Total
Net capitalized costs, end of period	$800,000	$1,400,000	$ 400,000	$2,000,000	$4,600,000
Estimated reserves, end of period (bbls)	180,000	680,000	1,500,000	400,000	2,760,000
Production during period (bbls)	20,000	20,000	100,000	0	140,000

If amortization is computed for each property individually, the total amortization for the period will be $145,000:

Property A:	$\frac{\$800{,}000}{200{,}000 \text{ bbls}}$	x 20,000 bbls	=	$ 80,000
Property B:	$\frac{\$1{,}400{,}000}{700{,}000 \text{ bbls}}$	x 20,000 bbls	=	40,000
Property C:	$\frac{\$400{,}000}{1{,}600{,}000 \text{ bbls}}$	x 100,000 bbls	=	25,000
Property D:	$\frac{\$2{,}000{,}000}{400{,}000 \text{ bbls}}$	x 0 bbls	=	0
Total amortization				$145,000

On the other hand, if the properties are combined into a single group, depletion for the period will be $222,069:

$$\frac{\$4{,}600{,}000}{2{,}900{,}000 \text{ bbls}} \times 140{,}000 \text{ bbls} = \$222{,}069$$

DEPLETION OF PROVED MINERAL INTERESTS

In Our Oil Company, the capitalized costs and related amortization for proved mineral interests are found in Account 221, Proved Leaseholds, and Account 226, Accumulated Amortization of Proved Property Acquisition Costs. Such costs are amortized over the property's total proved reserves:

> [C]apitalized acquisition costs of proved properties shall be amortized (depleted) by the unit-of-production method . . . on the basis of total estimated units of proved oil and gas reserves (Oi5.121).

It will be recalled that under the successful efforts method, costs of unproved properties are subject to an impairment test. Unproved properties whose costs are not individually significant may be combined into groups and their costs amortized on the basis of experience. The amortization of unproved properties and the grouping of unproved properties in making that computation are unrelated to production and are not included in the amortization discussed in this chapter. If impairment of unproved properties has been recorded on a group basis, the gross cost of properties that have been proved will have been transferred to the proved properties account. If impairment of an unproved property has been recorded on an individual basis, the net impaired cost (original cost less the impairment allowance) will have been transferred to proved properties if the property has become proved.

ILLUSTRATION OF DEPLETION COMPUTATION

As previously observed, amortization of mineral acquisition costs in the oil and gas industry is also referred to as *depletion.*

To illustrate Oi5.121 depletion requirements when a single proved property is treated as the cost center, assume the data given below for proved leasehold No. 24081. (Depletion and amortization of costs of nonoperating mineral interests are discussed later in this chapter.)

Cost initially transferred from unproved properties	$ 200,000
Depletion taken prior to beginning of this period	$ 20,000
Estimated proved reserves at beginning of this period	4,000,000 mcf
Production during this period	80,000 mcf
Revised estimate of proved reserves, end of period	4,920,000 mcf

Depletion for the year is thus $2,880:

$$\frac{\$200{,}000 - \$20{,}000}{(4{,}920{,}000 \text{ mcf} + 80{,}000 \text{ mcf})} \times 80{,}000 \text{ mcf} = \$2{,}880$$

Depletion for the period would be recorded as follows:

726 Amortization (Depletion) of Proved Property Acquisition Costs	2,880	
226 Accumulated Amortization of Proved Property Acquisition Costs		2,880

When depletion is computed for the individual property, a detailed record of the amortization applicable to each property is maintained.

Depletion of costs of a group of properties is computed in exactly the same manner as illustrated above for a single property, except that data for all properties in the group are combined. The grouping of properties is illustrated in the following section, in which depreciation of wells and related facilities and equipment is discussed. When properties are depleted on a group basis, a record is kept of accumulated depletion applicable to the group, and depletion is not considered to be related to individual properties.

DEPRECIATION OF PROVED PROPERTY WELL AND DEVELOPMENT COSTS

The capitalized costs of wells and related facilities include both tangible and intangible costs. In the general ledger accounts of Our Oil Company, these costs are kept separately in Account 231 for intangibles and Account 233 for tangibles. Oi5.126 suggests that the term *depreciation* may be given to amortization of tangible and intangible costs, although many companies still refer to the amortization of intangibles as depletion. This commonly used terminology probably stems from the fact that if IDC is capitalized for federal income tax purposes, it is subject to depletion for income tax reporting.

Amortize capitalized costs of wells and related facilities over proved developed reserves (but amortize acquisition costs over proved reserves):

> Capitalized costs of exploratory wells and exploratory-type stratigraphic test wells that have found proved reserves and capitalized development costs shall be amortized (depreciated) by the unit-of-production method . . . on the basis of total estimated units of **proved developed reserves** rather than on the basis of all proved reserves, which is the basis for amortizing acquisition costs of proved properties (Oi5.126).

For example, assume that a group of partially developed leases in a field has been combined into a single amortization pool. Relevant data are as follows:

Proved property acquisition costs	$ 240,000
Proved property intangible costs	$3,800,000
Proved property tangible costs	$ 600,000
Accumulated amortization of acquisition costs	$ 20,000
Accumulated amortization of intangible costs	$ 760,000
Accumulated amortization of tangible costs	$ 120,000

Proved developed reserves at year end	900,000 bbls
Proved reserves at year end	1,400,000 bbls
Production during period	100,000 bbls

Depletion and depreciation for the period are recorded as follows:

726	Amortization of Proved Prop. Acq. Costs	14,667*	
732	Amortization of Intangibles	304,000**	
734	Amortization of Tangibles	48,000***	
	226 Accumulated Amortization of Proved Property Acquisition Costs		14,667
	232 Accumulated Amortization of Intangibles		304,000
	234 Accumulated Amortization of Tangibles		48,000

To record amortization for period, as computed below:

* $\dfrac{\$240{,}000 - \$20{,}000}{1{,}400{,}000 \text{ bbls} + 100{,}000 \text{ bbls}} \times 100{,}000 \text{ bbls} = \$\ 14{,}667$

** $\dfrac{\$3{,}800{,}000 - \$760{,}000}{900{,}000 \text{ bbls} + 100{,}000 \text{ bbls}} \times 100{,}000 \text{ bbls} = \$304{,}000$

*** $\dfrac{\$600{,}000 - \$120{,}000}{900{,}000 \text{ bbls} + 100{,}000 \text{ bbls}} \times 100{,}000 \text{ bbls} = \$\ 48{,}000$

EXCLUSION OF PORTION OF SIGNIFICANT DEVELOPMENT PROJECTS

Development costs are to be amortized as the related proved *developed* reserves are produced. However, distortions in the amortization rate would occur if the amortization formula includes substantial development costs relating to both proved developed and proved undeveloped reserves.

To illustrate, assume that an offshore platform is constructed at a cost of $50,000,000 to be used to drill 15 development wells to extract an estimated 30,000,000 barrels of proved reserves. Prior to construction of the platform, two successful stratigraphic evaluation wells were drilled at a cost of $12,000,000. At the end of the current period, only two development wells have been drilled, at a cost of $3,000,000. During the current period 250,000 barrels were produced, and at the end of the period, the estimated remaining proved developed reserves to be produced from the two wells are 4,750,000 barrels.

The total capitalized costs of $65,000,000 divided by the 5,000,000 barrels of *beginning* proved developed reserves would provide a high current amortization rate of $13 per barrel. If all 15 wells had been drilled, increasing total capitalized costs to $84,500,000, then all 30,000,000 barrels of proved reserves would be developed, giving an amortization rate of only $2.82 per barrel. Clearly, to better match DD&A expense to revenue and production, it would be appropriate to exclude a portion of the $65,000,000 of capitalized costs from the amortization formula until all proved reserves are developed.

Oi5.126 provides for just such an adjustment to the formula:

> If significant development costs (such as the cost of an offshore production platform) are incurred in connection with a planned group of development wells before all of the planned wells have been drilled, it will be necessary to exclude a portion of those development costs in determining the unit-of-production amortization rate until the additional development wells are drilled.

Oi5.126 does not specify the method to be used in determining what portion of the platform costs and stratigraphic well costs are to be excluded from the amortization calculation. Presumably the exclusion would be based either (1) on the portion of total proved reserves estimated to be recoverable from the wells already producing or (2) on the basis of the ratio of wells already productive to the total number of wells projected.

Under the first approach, the amortization rate would be [($62,000,000 x 5/30) + $3,000,000] divided by 5,000,000 barrels, or $2.67 per barrel. Under the second approach, the amortization rate would be [($62,000,000 x 2/15) + $3,000,000] divided by 5,000,000 barrels, or $2.25 per barrel of production.

The capitalized costs temporarily excluded from amortization would eventually become part of the amortization base as additional wells are drilled. The costs of development wells drilled would be included in the amortization calculation as the costs are incurred, and the related reserves would be transferred to proved developed reserves.

The exclusion from the amortization base would apply not only to the platform costs but also to the capitalized costs of stratigraphic test wells that led up to the construction of the platform.

For successful efforts accounting, Oi5.126 does not allow a third approach of amortizing capitalized costs plus expected future development costs over total proved reserves. However, this approach is used in full cost accounting and illustrated in Chapter Nineteen. For the above example, the third approach would provide an amortization rate calculated as $84,500,000 divided by 30,000,000 barrels, or $2.82 per barrel.

DEVELOPED RESERVES REQUIRING ADDITIONAL DEVELOPMENT COSTS

Oi5.126 also provides for situations in which companies using the successful efforts method have developed reserves that may require additional costs to be incurred before the reserves can be produced:

> Similarly, it will be necessary to exclude, in computing the amortization rate, those proved developed reserves that will be produced only after significant additional development costs are incurred, such as for improved recovery systems.

This problem should not be commonly encountered, however, because paragraph (a)(3) of Reg. S-X Rule 4-10 defines proved developed reserves as follows:

> Proved developed oil and gas reserves are [proved] reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program confirmed through production response that increased recovery will be achieved.

In addition, the definition of proved undeveloped reserves in Reg. S-X Rule 4-10(a)(4) includes the following:

> Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

The purpose of all these rules is obviously to reasonably *match* revenue and production with applicable costs. However, unit-of-production amortization is not perfect, as discussed briefly at the end of this chapter.

DISMANTLEMENT, RESTORATION, AND ABANDONMENT COSTS

Oi5.128 requires that:

> estimated dismantlement, restoration, and abandonment costs and estimated residual salvage values shall be taken into account in determining amortization and depreciation rates.

See Chapter Twenty on accounting for such costs under existing and proposed standards. In the 1990's and 1980's, the future cost of dismantlement, restoration, and abandonment ("DR&A") was added to the current amortization base so as to increase DD&A to accrue for DR&A over the property's productive life. However, the estimated future costs were not added to the asset accounts.

The February 2000 proposed statement of financial accounting standards *Accounting for Obligations Associated with the Retirement of Long-Lived Assets* calls for a DR&A liability to be recognized when the obligation is incurred, e.g., when the well is drilled or when the producing property is acquired. The amount of the recognized liability is added into the amortizable capitalized costs of acquiring or developing a property. Unlike current rules that use undiscounted future DR&A, the proposed rules recognize the liability at the discounted present value of future DR&A.

JOINT PRODUCTION OF OIL AND GAS

If both oil and gas are found on a property (or group of properties, if a geological group is being used as a basis for amortization), the amortization should normally be calculated on the basis of estimated total equivalent units of oil and gas, with the equivalent units being expressed in terms of relative energy content, i.e., Btu content. (An equivalent unit based on revenues is specifically prohibited for companies using the successful efforts method, yet it is allowed for full cost accounting.) The energy content of both oil and gas varies from reservoir to reservoir, and even within a single reservoir. As noted in Chapter One, many companies use a general approximation that one barrel of oil contains six times as much energy as does one thousand cubic feet (mcf) of gas. Other companies may attempt to be more precise in their calculations, however, and use the actual equivalent energy content for oil and gas in the property or group of properties making up the amortization unit.

To illustrate this concept, assume that the following data apply to a fully developed property:

Capitalized costs	$6,000,000
Amortization in prior periods	$ 240,000
Estimated oil reserves, end of period	620,000 bbls
Estimated gas reserves, end of period	3,300,000 mcf
Oil production during period	70,000 bbls
Gas production during period	360,000 mcf

The amount of amortization for the period is computed as follows, converting gas volumes to barrels of oil equivalent

Reserves, end of the period:	
Oil (620,000 bbls x 1)	620,000 boe
Gas (3,300,000 mcf/6)	550,000 boe
Total equivalent barrels, end of period	1,170,000 boe
Production for the period:	
Oil (70,000 bbls x 1)	70,000 boe
Gas (360,000 mcf/6)	60,000 boe
Total equivalent barrels produced	130,000 boe
Total equivalent barrels, beginning of period	1,300,000 boe

Amortization for the period would be $576,000, computed as shown:

$$\frac{130{,}000 \text{ boe}}{1{,}300{,}000 \text{ boe}} \times (\$6{,}000{,}000 - \$240{,}000) = \$576{,}000$$

Some companies, especially gas producing companies, may wish to convert oil to gas equivalents, an approach that will not change the results of the computation. This procedure is illustrated below:

Reserves, end of the period:	
Oil (620,000 bbls x 6 mcf per bbl)	3,720,000 mcfe
Gas (3,300,000 mcf x 1)	3,300,000 mcfe
Total equivalent mcf, end of period	7,020,000 mcfe
Production for the period:	
Oil (70,000 bbls x 6 mcf per bbl)	420,000 mcfe
Gas (360,000 mcf x 1)	360,000 mcfe
Total equivalent mcf produced	780,000 mcfe
Total equivalent mcf, beginning of period	7,800,000 mcfe

Amortization for the period would be $576,000:

$$\frac{780{,}000\text{ mcfe}}{7{,}800{,}000\text{ mcfe}} \times (\$6{,}000{,}000 - \$240{,}000) = \$576{,}000$$

Although the general presumption of Oi5.129 is that if both oil and gas are found in a property or group of properties forming an amortization group, amortization should be based on a cost per equivalent unit, Oi5.129 provides for two specific exceptions to this rule:

> However, if the relative proportion of gas and oil extracted in the current period is expected to continue throughout the remaining productive life of the property, unit-of-production amortization may be computed on the basis of one of the two minerals only; similarly, if either oil or gas clearly dominates both the reserves and the current production (with dominance determined on the basis of relative energy content), unit-of-production amortization may be computed on the basis of the dominant mineral only.

The first exception can be illustrated using the data from the preceding example. Since oil represents 53 percent of the energy content of minerals in the reservoir at the end of the period and 54 percent of the energy content of the minerals produced during the current period, relative production of oil and gas in the current period is approximately the same as it will be in future periods, so that production and reserves of only one mineral may be used in the calculation, if the entity desires. If only oil production and reserves are considered, the amortization for the period would be $584,348:

$$\frac{70{,}000 \text{ bbls}}{690{,}000 \text{ bbls}} \times \$5{,}760{,}000 = \$584{,}348$$

In the above example, since neither mineral is clearly dominant in both reserves and production (oil accounts for only 53 percent of the energy content in reserves and only 54 percent of the energy content of current production), use of a single mineral could not be justified on the basis of dominance. Oi5.129 does not explain what is meant by the term "clearly dominates". It would seem reasonable to assume, however, that if three-fourths or more of the energy content of both production and reserves were attributable to one mineral, that mineral clearly dominates. On the other hand, if the energy content of either production or reserves attributable to one mineral is no more than two-thirds of the total energy content of that category, one mineral cannot be considered clearly dominant. Based on this rule of thumb, the situation must be carefully analyzed if the ratio is between two-thirds and three-fourths.

REVISIONS OF INTERIM ESTIMATES

In the examples in this chapter, DD&A has been computed for the *period*, with the length of the period not specified. When reserve estimates are changed during the year, however, the definition of the period becomes important.

Oi5.126 requires that amortization rates "be revised whenever there is an indication of the need for revision but at least once a year." During a fiscal year, revisions in the rate may be indicated by such matters as (1) major discoveries, (2) other reserve additions, or (3) major price changes which impact the volume of proved reserves. Companies are cautioned against blindly using predetermined DD&A estimates and not revising the reserve estimates or amortization rate until the end of the year.

APB Opinion No. 20 requires that changes in reserve estimates be treated on a *prospective* basis. This requirement has been interpreted in different ways in practice. Two general approaches were reported in the *1999 PricewaterhouseCoopers Survey of U.S. Petroleum Accounting Practices.* The following example will be used to illustrate both.

Assume that depreciation is being recorded quarterly and reported in quarterly statements. Assume that on January 1, 2000, the first day of the fiscal year, undepreciated costs of wells and facilities on a property are $6,000,000 and estimated proved developed reserves are 1,000,000 barrels. During the first quarter, ending March 31, 2000, 20,000 barrels are produced; during the second quarter, ending June 30, 18,000 barrels are produced; and during the third quarter ending September 30, 22,000 barrels are produced. Thus, depreciation recorded in the first three quarters was $120,000, $108,000, and $132,000, respectively. In October, 6,000 barrels are produced, and in November, 8,000 barrels are produced. In December, a revised estimate of proved developed reserves is made, showing that on December 1 estimated reserves are 626,000 barrels. The revised estimate as of October 1 is, therefore, 640,000 barrels, and the revised estimate as of January 1, 1995, is 700,000 barrels. Production during December is 6,000 barrels.

In the first popular approach, the *period* is the last quarter, in which reserves are revised. Amortization for the year will then be the sum of the four quarterly amortization amounts. Under this approach, using the assumed facts previously given, the amortization for 2000 will be computed as follows:

Amortization for the first three quarters	$360,000
Amortization for the fourth quarter:	
$\frac{\text{20,000 bbls}}{\text{640,000 bbls}}$ x ($6,000,000 - $360,000) =	176,250
Total depreciation for the year	$536,250

Under the second popular approach, the *period* is the fiscal year-to-date. Using this approach DD&A is computed for the interim period as if the reserves were added at the beginning of the year:

Amortization for the year:	
$\frac{\text{80,000 bbls}}{\text{700,000 bbls}}$ x $6,000,000 =	$685,714
Less prior interim amortization	(360,000)
Amortization for the 4th qtr.	$325,714

AMORTIZATION OF NONOPERATING INTERESTS

The costs of nonoperating interests, like the costs of operating interests, should generally be depleted or amortized on the unit-of-production basis. Oi5.121 provides that in certain circumstances, other methods of computing amortization may be appropriate:

> If an enterprise has a relatively large number of royalty interests whose acquisition costs are not individually significant, they may be aggregated, for purpose of computing amortization, without regard to commonality of geological structural features or stratigraphic conditions; if information is not available to estimate reserve quantities applicable to royalty interests owned (refer to paragraph .160), a method other than the unit-of-production method may be used to amortize their acquisition costs.

There are two major difficulties in implementing the unit-of-production method for nonoperating interests. First, many nonoperating interests may be quite small in both cost and value, so that they are individually immaterial. Second, operating interest owners are quite likely to refuse to provide information to nonoperating interest owners concerning proved reserves underlying a property or field, especially when the royalty interest is small and the royalty owner is not an operating oil and gas company. The royalty owner may be able to approximate the reserves by projecting the decline curve from the property, based on past production history.

Oi5.121 implies that if a single royalty interest is significant, its capitalized costs should be amortized over the related proved reserves from the property. Royalty interests in a field or reservoir may also be combined without regard to geologic commonality and amortized as the related proved reserves are produced. More commonly, however, because of the lack of information necessary to compute unit-of-production amortization, royalty costs are combined and amortized on a straight-line basis over a period of eight to ten years, since overall U.S. proved reserves are about eight to ten times overall production.

Although Oi5.129 refers specifically to royalties (including overriding royalties), the same basic concepts apply to net profits interests. Conceptually, the unamortized costs of a net profits interest would be depleted on the basis of (1) the production on which the net profit for the period is determined and (2) on the fractional share of reserves represented by the net profits interest. However, working interest owners may be reluctant to inform a net profits interest owner of the estimated proved reserves underlying the property or properties, so that amortization based on the straight-line method may be a logical approach to computing depletion.

The holder of a production payment payable in product would amortize cost on the basis of production received if there is reason to believe that the payment will be satisfied. For example, if the entity obtained for

$1,000,000 a production payment of 1,000,000 mcf of gas and during the current period received the first 250,000 mcf, with reasonable assurance that the remaining 750,000 mcf will be received, depletion of $250,000 [$1,000,000 x (250,000 mcf ÷ 1,000,000 mcf)] should be recorded and matched against the value of the gas received during the period.

If it is doubtful that the total number of units to be delivered under a production payment expressed in physical quantities of minerals will be received, but an estimate of product that will be received can be made, then a portion of the costs should be amortized based on the ratio of units delivered to total expected to be delivered. For example, if (1) $1,500,000 is paid for a production payment to be satisfied by delivery of 1,000,000 mcf of gas, (2) during the current period the first 100,000 mcf of gas are received, and (3) it is estimated that only an additional 500,000 mcf will be received in the future, then depletion would be $250,000 [$1,500,000 x (100,000 mcf/ 600,000 mcf)]. On the other hand, if it is doubtful that the full amount will be satisfied, but there is no information available on the quantity that will ultimately be delivered, a good case can be made for ignoring depletion and for treating the entire value of the gas received as a recovery of the $1,500,000 cost of the production payment.

ALLOWABLE METHODS OTHER THAN UNIT- OF-PRODUCTION

Although Oi5.126 specifies that the unit-of-production method should be used in depreciating the costs of wells and related facilities and equipment, there are limited situations in which other methods may be used. Oi5.126 mentions one exception:

> It may be more appropriate, in some cases, to depreciate natural gas cycling and processing plants by a method other than the unit-of-production method.

Presumably, if a cycling or processing plant serves only one lease or one group of leases combined for amortization purposes, the unit-of-production method should be used. However, when a cycling or processing plant serves a number of properties subject to individual amortization, or when the plant is used to process gas for other operators on a contract basis, some other depreciation method would be appropriate. Many companies consider processing plants to be more akin to refining facilities than to oil and gas producing assets.

Another instance in which a depreciation method other than the unit-of-production method appears to be appropriate is one in which assets with significant costs have a useful life substantially shorter than the productive life of the property on which they are situated. However, this is not specifically addressed in Reg. S-X Rule 4-10 or Oi5.

DEPRECIATION OF SUPPORT EQUIPMENT AND FACILITIES

Support facilities such as warehouses, camps, trucks, office buildings, and communications equipment frequently provide service to two or more functions (exploration, acquisition, development, and production). For example, a district warehouse will serve all four of those functions. Even in cases in which support equipment is used in only one activity, such as production, it may be impossible to identify the asset with only a single property or group of properties in a single amortization base. Consequently, the unit-of-production method based on oil and gas produced may not be an appropriate method for depreciating support equipment. Instead, the straight-line method, the unit-of-output method, based on some factor such as miles driven (for trucks), or other acceptable basis should be used. This creates no unique accounting problems.

As pointed out in Chapter Four, depreciation and other costs of owning and using support equipment should be allocated to operating activities on the basis of usage and, consequently, expensed or capitalized as appropriate. For example, to the extent that an asset is used in development, its depreciation and operating costs are capitalized, whereas depreciation and operating costs related to its use in production activities will be charged to expense. This cost allocation may be accomplished through clearing and apportionment accounts, as discussed in Chapter Four.

A SUCCESSFUL EFFORTS AMORTIZATION EQUATION

Based on the issues raised in this chapter, the unit-of-production equation or formula may be expressed as follows for a given cost center (i.e., the property or a reasonable aggregation of properties):

Amortization expense = B x S/(S+R), where:

- B = the amortization base, defined below;

- S = volume sold during the period (i.e., equivalent barrels or mcfs or the volume of the dominant hydrocarbon); and
- R = the volume of proved reserves at the end of the period using *developed* reserves for well and equipment DD&A, but using *total* proved reserves for property acquisition DD&A.

The amortization base = C-A+D-V-E, where:

- C = incurred capitalized costs of mineral property interests or of wells and development;
- A = the prior accumulated amortization;
- D = the estimated undiscounted future dismantlement and reclamation costs or P&A costs;
- V = the estimated undiscounted future salvage value of the lease equipment; and
- E = the capitalized development costs excluded from the amortization base as allowed by Oi5.126.

Note that D, V, and E will not apply for DD&A of mineral property acquisition costs. Proposed DR&A rules (Chapter Twenty) have D and V already in C.

The formula for full cost addressed in Chapter Nineteen is very similar but is countrywide, uses total proved reserves, and adds to the amortization base *F* for future development costs of properties in the amortization base.

SHRINKAGE

Units sold (S) could arguably be replaced with units produced, but the two volumes are nearly equal over quarterly or annual periods. In some instances, units sold are significantly less than units produced, the difference being called *shrinkage*. Shrinkage may arise from natural gas used on the lease, gas volumes lost in processing for extraction of NGL, removal of impurities and BS&W, and even theft or pipeline leaks. Where shrinkage is significant, the amortization calculation should use units produced or sold (S) and proved reserves (R) that are both before shrinkage or both after shrinkage so that costs will be reasonably allocated over the productive life of the reserves.

The *1999 PricewaterhouseCoopers Survey of U.S. Petroleum Accounting Practices* shows that when volumes sold differ from volumes produced, volumes sold are generally used for calculating amortization both under successful effort and full cost accounting. Of 45 respondents, 28 (or 62 percent) used volumes sold; 17 (or 38 percent) used volumes produced; one respondent reported using both.

TAX TREATMENT FOR DEPLETION AND DEPRECIATION

For federal income tax purposes, the IRS has established specific rules regarding the computation of depletion and depreciation of oil and gas properties. Tangible well equipment is capitalized as personal property and depreciated in accordance with IRS depreciation guidelines. Leasehold costs are generally depleted over the greater of the units-of-production method or at a statutory rate based on the property's revenue and net income, as explained further in Chapter Twenty-Six.

A PROBLEM WITH THE UNIT-OF-PRODUCTION METHOD

The unit-of-production method mandated by Oi5.126 is far from perfect. Over the economic life of an oil field, as production declines, cash flow per barrel declines to zero, while amortization per barrel may remain relatively constant. The unit-of-production method mandated in Oi5.126 results in income per barrel generally declining over the life of the field and even being at a loss in the later years, as illustrated in the following example for a property expected to produce for seven years:

Year	Net Bbls	Revenue ($20/bbl)	Oper. Costs	Cash flow/bbl	DD&A per bbl*	Net Income per bbl	Net Income	Year-End Net Unamor-tized Cost	Year-End Future Cash Flow
0								$25,000	$30,000
1	1,000	$20,000	$10,000	$10.00	$5.00	$5.00	$5,000	20,000	20,000
2	890	17,800	10,000	8.76	5.00	3.76	3.350	15,550	12,200
3	780	15,600	10,000	7.18	5.00	2.18	1.700	11,650	6,600
4	690	13,800	10,000	5.51	5.00	0.51	350	8,200	2,800
5	600	12,000	10,000	3.33	5.00	(1.67)	(1,000)	5,200	800
6	530	10,600	10,000	1.13	5.00	(3.87)	(2,050)	2,550	200
7	510	10,200	10,000	0.39	5.00	(4.61)	(2.350)	0	0
	5,000	$100,000	$70,000	6.00	5.00	1.00	$5,000		

* Ignoring application of FAS 121

For simplicity, this example assumes expected future cash flow based on a constant oil price of $20.00 per barrel and constant fixed operating costs of $10,000 per year. This example shows a property generating $5,000 net income over its seven-year life, and all of the income is recognized in the first year due to amortization based on reserve volumes rather than expected future net cash flow. By the end of Year 2, unamortized costs are already impaired per FAS 121 (i.e., such costs of $15,550 exceed $12,200 in undiscounted future cash flows).

This example's property averages $1.00/bbl of net income over the seven-year life. Arguably, to better match revenue and expense, DD&A expense should ideally reflect the $1.00/bbl of net income every year. However, the example illustrates that unit-of-production amortization tends to overstate net income per barrel in the early life of a producing property and understate it in the later years. In other words, in any one year the method generally understates amortization for new producing property and overstates amortization for old producing property.

For an ongoing oil and gas producing company, the understatement of amortization for new fields' capitalized costs compensates to some degree for the overstatement of amortization of old fields' costs. However, without new fields, a liquidating company will find net income per barrel declining over time.

This mismatching of revenue and expense also causes capitalized costs for any one field to become impaired over time, arguably necessitating impairment write-offs under FAS 121 to avoid losses in the later years of the field's productive life.

Revenues would be better matched with costs, and income per barrel would be more level over the property's productive life if the capitalized costs were amortized over projected cash flow from production of proved reserves, instead of over units of production. This method, not provided for in Oi5 or Reg. S-X Rule 4-10, seeks for the combined cost of amortization expense and lifting cost, per equivalent barrel, to be relatively constant over the life of the property. This method, for the simplistic example above, would adjust DD&A so that net income per barrel was always $1.00 if oil and gas prices and lifting costs remained constant.

FAS 121 accounting for long-lived asset impairment (addressed in Chapter Eighteen) and the full cost ceiling test (addressed in Chapter Nineteen) partially compensate from time to time for any significant mismatching of revenue and expense arising from the unit-of-production amortization method applied to oil and gas producing activity.

Chapter Eighteen

ACCOUNTING FOR THE IMPAIRMENT OF LONG-LIVED ASSETS

OVERVIEW

In March 1995, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to Be Disposed Of* (*FAS 121* or *the Statement*). FAS 121 addresses accounting for the impairment of long-lived assets, certain identifiable intangibles, and goodwill related to those assets to be held and used. The Statement also addresses the accounting for long-lived assets and certain identifiable intangibles to be disposed of.

For successful efforts companies, the impairment provisions of FAS 121 are applicable for proved properties and related equipment and facilities, whereas unproved properties are subject to the impairment provisions of FAS 19 and Reg. S-X Rule 4-10 (see Chapter Seven for further discussion on the impairment and abandonment of unproved properties). Full cost ceiling provisions in Reg. S-X Rule 4-10 are applicable in assessing impairment of the full cost pool (see Chapter Nineteen for further discussion of the full cost ceiling test).[53]

FAS 121 requires a two-tiered approach for assessing impairment:

1. Whenever events or changes in circumstances indicate that the asset's carrying amount may not be recoverable, the entity estimates expected future cash flows from the asset's use and ultimate disposal. If the asset's carrying amount exceeds such cash flows (undiscounted and without interest charges), the entity must recognize an impairment loss as calculated in the following step. This comparison is usually based on pre-tax cash flows.
2. The impairment loss is measured as the amount by which the asset's pre-tax carrying amount exceeds its fair value.

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[53] For a discussion of how FAS 121 impairment rules differ from the pre-1996 successful efforts ceiling test, see Chapter Eighteen of the 4th Edition (1996) of *Petroleum Accounting Principles, Procedures, & Issues.*

Events or new circumstances must occur which indicate that an asset may be impaired. An asset's carrying value is required to be assessed only when there are indications that its carrying value may not be recoverable. If the asset's expected undiscounted future cash flows, as calculated in Step 1 above, are more than its carrying value, the asset's carrying value is considered recoverable, and there is no impairment loss to measure.

FAS 121 is a broad-based standard that provides only general measurement guidelines. The following is a simple example of a successful efforts company applying FAS 121 for proved properties:

Assumptions

- Proved oil and gas properties and related equipment are grouped on a field basis for impairment purposes.
- The company has 20 proved fields.
- During the current reporting period, management made downward revisions in proved crude oil reserve estimates of three nonoperated fields (Fields A, B, and C). The downward reserve revisions are due to significantly reduced planned development activities as a result of recent changes in regulations pertaining to the disposal of produced water for these offshore Louisiana properties.
- Field A, B, and C have fair values of $3, $5, and $4 million, respectively (using expected future cash flows from reserves discounted at the market's current rate of return).

Example

	(in millions)		
	Field A	Field B	Field C
Capitalized cost of proved properties	$ 5	$20	$10
Accumulated DD&A	(2)	(8)	(3)
Liability for plugging & abandonment[54]	nil	(2)	(1)
Deferred revenue for volume production payment on Field C [55]	0	0	(3)
Net book value	$ 3	$10	$ 3

[54]Some companies may record the accrued liability for plugging and abandonment as a separate liability rather than as a component of accumulated DD&A. See Chapter Twenty on application of proposed standards for asset retirement obligations.

[55]Reducing book value for any related deferred revenue for a volume production payment (VPP) is addressed at the end of this chapter.

Deferred income taxes are generally ignored for determining net book value. However, an exception to this rule is addressed later in this chapter.

Recognition test	Field A	(in millions) Field B	Field C
Future undiscounted expected cash flows before taxes	$ 4	$ 8	$ 8
Net book value	$ 3	$10	$ 3
Impairment loss	No	Yes	No

Measurement of impairment

Net book value, ignoring deferred income taxes	$10
Fair value	(5)
Impairment loss	$ 5

Notice that the measurement of impairment is also a pre-tax amount. Net book value has not been reduced by related deferred income taxes, and fair value is what the asset would sell for. The impairment loss is not based on any income taxes (or income tax benefits) resulting from selling the asset for fair value at a gain (or loss). So the adjusting journal entry to record the impairment loss treats it like any pre-tax expense, whereby the effect on the income tax provision must also be computed and recorded.

For this example:

- The income statement's impairment loss account would be debited for $5 million, and the impaired asset's accumulated DD&A would be credited for $5 million.
- If the effective income tax rate were 40 percent, an additional entry would debit balance sheet deferred income taxes for $2 million, and the deferred income tax provision would be credited for $2 million.
- The $5 million impairment loss would reduce net income by $3 million.

In comparison, the *ceiling writedown* under the full cost ceiling test explained in Chapter Nineteen is an after-tax amount equivalent to the $3 million in the example above.

Paragraph 13 of FAS 121 requires the impairment loss to be reported as a component of income from continuing operations before income taxes for entities which have a multi-tier income statement. In addition, the company's policy for assessing and measuring impairment of its long-lived assets should be disclosed in the notes to financial statements.

Paragraph 14 of FAS 121 requires the following disclosures in financial statements for each period in which an impairment loss was recognized:

1. Description of the impaired assets (e.g., type of assets, location, fields) and the facts and circumstances leading to the impairment;
2. The way fair value was determined;
3. The amount of impairment loss, disclosed either on the face of the income statement or in a note to the financial statements stating in which caption on the income statement the impairment loss is aggregated; and
4. The business segment impacted by the impairment loss, if applicable.

APPLICATION ISSUES

This section addresses several issues that may arise in applying FAS 121 to proved properties, including wells and facilities.

INHERENT IMPAIRMENT UNDER UNIT-OF-PRODUCTION AMORTIZATION

The last subsection of Chapter Seventeen explained how property impairment is inherent if the required unit-of-production amortization method is used.

Due to unit-of-production amortization and the fact that many operating costs are *fixed costs* rather than *variable costs*, the likelihood of impairment increases with time as an asset group's production declines to its economic limit. For example, if reserves were acquired at $5 per boe, the expected DD&A rate would be $5/boe produced. However, as production declines with time, net cash flows per equivalent barrel also decline (eventually to zero) because operating costs, many of which are fixed, are spread over fewer units of production. Thus, in the asset group's later years, cash flow per boe will be less than the $5 per boe needed to recover the asset group's unamortized carrying costs, as was illustrated at the end of Chapter Seventeen. The problem may be lessened by upward reserve revisions over the productive life, but the problem remains inherent in this amortization method.

Paragraph 6 of FAS 121 notes that the impairment assessment process may indicate the need to review depreciation policies. However, Oi5 permits only the unit-of-production amortization method for successful efforts companies (full cost companies may use a unit-of-revenue amortization method under certain circumstances). Thus, for older properties the unit-of-production method will continue to trigger impairment write-downs as the properties approach their economic limits.

IMPAIRMENT INDICATORS

FAS 121 requires management to review the carrying value of proved oil and gas properties if events or changes in circumstances indicate that the carrying value may not be recoverable. Impairment indicators could include the following:

- The passage of time due to unit-of-production amortization, as explained above;
- Lower expected future oil and gas prices (such as those used by management in evaluating whether to develop or acquire properties);
- Actual or future development costs significantly more than previously anticipated for a group of properties (e.g., significant AFE overruns with no significant upward revisions in reserve estimates);
- Significant downward revisions to a field's reserve estimates; and
- Significant adverse change in legislative or regulatory climate (e.g., unanticipated increase in severance tax rates).

SEC registrants will have to address impairment in the operating results of the quarter in which the events or circumstances occur that indicate an asset group may be impaired (i.e., impairment losses should be recorded in the quarter in which events or circumstances occurred that gave rise to the impairment, as opposed to addressing impairment only in the year-end operating results).

It may be prudent for some companies to use quarterly benchmarks, such as budgeted quarterly cash flow, to monitor for indications of impairment in a timely manner. For example, if the most recent analysis of expected future cash flow was $100,000 for the current quarter and actual cash flow for the quarter is significantly less than the $100,000 benchmark, an updated analysis may be needed.

For companies that maintain a computer file of expected future cash flows by asset or asset grouping, it may be more expedient to simply update quarterly the expected future cash-flow analysis for changes in future price expectations and for significant known changes in proved reserves instead of looking for indicators. At a minimum, companies should typically update the analysis at year-end when reserve estimates and the standardized measure are revised. With today's E&P economic analysis software, the pre-tax standardized measure is routinely computed and saved by well. From such data, expected future cash flow from proved reserves is easily generated by changing pricing and cost-escalation assumptions. Arguably, the annual update could be skipped for properties with capitalized costs well below expected future cash flows in the prior analysis, but it may be more efficient to simply update the analysis for all properties than to take time to justify internally and to financial statement auditors that a full analysis was not required.

ASSET CARRYING AMOUNT

FAS 121 is silent in defining what constitutes a long-lived asset's *carrying amount*. Generally, this is the asset's net book value, i.e., cost less accumulated DD&A. Deferred income taxes are usually ignored.

For a fair comparison with expected undiscounted future cash flows and fair value, other balance sheet accounts may need to be consistently disregarded or considered, as discussed below for accrued DR&A costs and VPP deferred revenue.

Ignoring Deferred Income Taxes—Usually

Unlike the full cost ceiling test, the asset's carrying value for the purpose of comparison with related expected undiscounted future net cash flow (to determine whether there is potential impairment, as required by FAS 121) is usually without adjustment for deferred income taxes. If the asset's carrying value, i.e., book value, is $1 million and the expected future cash flow is $1 million, then the related future income taxes will generally equal or closely approximate related deferred income taxes, since the tax basis and the tax rate would typically be the same in computing future income taxes as in computing deferred income taxes. If expected pre-tax cash flow is significantly different from the asset's carrying value, then future income taxes will similarly be different from deferred income taxes, but not enough to change whether or not impairment is to be recognized. Therefore, the consideration of future income taxes and recorded deferred income taxes in the comparison is generally an impractical refinement to an already imperfect *trigger* of impairment recognition.

In early 1995, the FASB considered amending draft FAS 121 Paragraph 7 to specifically state that future cash flows would be *without income taxes* as well as without interest charges. However, some long-lived assets (such as some E&P properties producing coalbed methane) generate substantial income tax credits that enhance asset value. When such tax benefits came to the attention of the FASB, it decided to omit the *without income taxes* qualifier from paragraph 7 in the final FAS 121 to allow consideration of such tax benefits. So in computing expected future cash flow, companies are free to consider any special income tax benefits, such as Section 29 tax credits for certain production of natural gas from coal seams that would significantly reduce future income taxes below the recorded deferred income taxes. With Section 29 tax credits expiring for production after 2002, FAS 121 impairment determinations that consider income taxes should be increasingly rare.[56]

Despite use in the full cost ceiling test, deferred income taxes are not relevant for determining fair value or for measuring impairment under FAS 121 as noted on page 445. Fair value can be determined using either pre-tax or after-tax cash flows, appropriately discounted, as discussed in Chapter Thirty. Regardless, the calculated values are estimates of the same fair value; there is not both a fair value after taxes and a fair value before taxes. Fair value is what a third party will pay for the asset whereby the third party's purchase price becomes the property's new tax basis. Fair value of a producing property ignores how the seller's tax liability changes for any gain (or loss) relative to the asset's income tax basis. The asset's carrying amount is without regard to deferred income taxes in comparing it to fair value for measuring impairment loss.

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[56] For an example on how to consider income taxes in FAS 121 impairment determinations for proved property, see Chapter Eighteen of the 4th Edition (1996) of *Petroleum Accounting Principles, Procedures, & Issues*.

Consideration of Accrued DR&A Liabilities

As discussed in Chapter Twenty, the FASB has issued an Exposure Draft (ED) proposing that asset retirement obligations (ARO) be accrued as a liability when the obligations arise, e.g., when the field is explored and developed. In accruing the obligation, the asset carrying value is increased by the initial accrual. The ED's paragraph 12 proposes that the accrued liability and the corresponding future ARO liability be disregarded for FAS 121 impairment, i.e., ignored and not used to reduce the expected future cash flow and the asset's fair value, since the asset carrying amount is increased by the initial ARO accrual. This approach may not be in the final standard since the approach reduces any excess of asset base over expected future cash flow to the extent that the undiscounted expected ARO exceeds the accrued ARO liability.

Prior to adoption of the proposed ARO standard, a producing property's future dismantlement, restoration and abandonment costs (called either DR&A or ARO costs) are accrued over the proved property's productive life through increased DD&A expense. Many companies reflect the additional DD&A as a reduction of the asset's carrying value. In such cases, it is reasonable to reduce expected future cash flows for expected future ARO costs and have fair value reflect the ARO burden. If the additional DD&A for ARO is credited to a liability account instead, then the asset's carrying amount should be net of the ARO liability. In that way, the FAS 121 impairment tests reasonably consider the ARO aspects.

Consideration of VPP Deferred Revenue

Chapter Twenty-Three explains that FAS 19 requires the sale of a VPP from a proved property to be regarded as a sale of a mineral interest which reduces reserves. However, the cash proceeds are credited to deferred revenue rather than to the oil and gas property asset. Thus, the sale of a VPP reduces reserves and expected cash flow without reducing the carrying amount or book value of the asset. It seems reasonable, then, that for an FAS 121 impairment recognition test, the asset's *carrying amount* should be net of any related VPP deferred revenue for comparison to expected future cash flow from net reserves.

Similarly, for measuring impairment loss, the asset's carrying amount should be net of any related VPP deferred revenue for comparison to the fair value of the net unsold property.

ASSET GROUPING

Producing Assets Are Commonly Grouped by Field

Paragraph 8 of FAS 121 states that "assets shall be grouped at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets."

As discussed in paragraph 102 of FAS 121, the FASB does not endorse the view that assets should be grouped in the same manner they are managed, or on a country-by-country basis. As a result, the FASB significantly discounted the fact that a large number of energy companies have integrated field operations, upstream and downstream facilities, vast marketing infrastructures, and risk-management functions that were specifically implemented to optimize the ultimate price received for hydrocarbons. These integrated and diverse activities ensure the aggregation of sufficient quantities of hydrocarbons to maximize transportation discounts, satisfy locational exchanges and differentials, and meet demand for feedstocks to maximize downstream profits. The FASB was not persuaded by such arguments.

The *1999 PricewaterhouseCoopers Survey of U.S. Petroleum Accounting Practices* found that all six of the major oil companies responding to the survey group E&P assets by field. Of the 30 responding independents using successful efforts, 16 (53%) grouped the assets by field. Eight grouped by well; four by lease.[57]

Grouping proved properties on a field basis is generally appropriate due to sales arrangements or to the existence of common field facilities. Most sales arrangements involve production from several wells within a given field, and the production from each well, may be dedicated to several purchasers. These arrangements require that sales proceeds from intermingled production of several wells be allocated based on each well's adjusted production volumes. The purchaser is not necessarily trying to acquire the production from a given well, but is contracting to obtain a given quantity of hydrocarbons, regardless of which wells in the field produced the hydrocarbons. Thus, the terms and arrangements to sell a well's production are dependent upon the quantity and quality of the

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[57] For a discussion of the merits and shortcomings of impairment assessment by well, see Chapter Eighteen of the 4th Edition (1996) of *Petroleum Accounting Principles, Procedures, & Issues.*

production of all wells dedicated to the sales contract. Also, wells within a given field generally share common production facilities. This cost sharing also indicates that cash flows from a given well or lease are not largely independent, since total costs of a common facility are directly related to the operations of all wells which share the facility rather than to the operations of a single well. In addition, the operations of a well typically succumb to, and are directly impacted by, operational and regulatory constraints of the field.

Grouping certain proved fields together, or grouping proved fields with downstream activities, may be appropriate in assessing impairment if the cash flows of these operations are directly dependent upon each other. However, such groupings appear to be the exception and not the norm.

DETERMINING EXPECTED FUTURE CASH FLOWS

Expected future cash flows are defined in paragraph 6 of FAS 121 as "the future cash inflows expected to be generated by an asset less the future cash outflows expected to be necessary to obtain those inflows (undiscounted and without interest charges)." FAS 121, Paragraph 9 states:

> Estimates of expected future cash flows should be the best estimate based on reasonable and supportable assumptions and projections. All available evidence should be considered in developing estimates of expected future cash flows. The weight given to the evidence should be commensurate with the extent to which the evidence can be verified objectively. If a range is estimated for either the amount or timing of possible cash flows, the likelihood of possible outcomes shall be considered in determining the best estimate of future cash flows.

A determination of expected future cash flows should consider the following:

1. **Reserves.** Proved, probable, and arguably possible reserves should be considered (appropriately risk reduced) in estimating expected future cash flows. Paragraph 9 of FAS 121 calls for "considering the likelihood of possible outcomes," which allows companies to consider probable and possible reserves, but the likelihood of

possible reserves may be so remote that their incremental effect on *expected* future cash flow is nominal.

As explained on page 395, probable reserves are defined by the SPE and WPC as unproved reserves more likely than not to be recoverable whereby there is at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of estimated probable and proved reserves whereby expected future production is the sum of proved and probable reserves. However, in the *1999 PricewaterhouseCoopers Survey of U.S. Petroleum Accounting Practices*, only 21 percent of the successful efforts respondents considered probable reserves for determining FAS 121 impairment. Further, Chapter Thirty shows SPEE annual surveys indicate that probable reserves are substantially discounted in evaluation of properties.

For expediency a company may use only proved reserves to quickly eliminate many properties from the list of potentially impaired properties. For the remaining properties, a more refined determination of future cash flows using proved, probable, and possible reserves could be made.

2. **Prices.** Future prices should be in nominal dollars, i.e., adjusted for expected inflation, and should be management's best estimate. Such prices should have a high correlation with the future pricing assumptions management uses in its long-range budgeting process, property acquisition, and property divestiture programs. Management's price estimates may be derived from actual contracts or independent public forecasts such as found in the *Oil & Gas Journal*'s semi-annual price forecast compendiums or in the SPEE annual *Survey*[s] *of Economic Parameters Used in Property Evaluations* noted in Chapter Thirty. Future contracts (Chapter Thirty-Two) available at the valuation date may be used to establish or reflect short-term *expected* prices adjusted for basis differential(s). Prices should reflect the value of hydrocarbons at the well-head or at the point of transfer from the asset group, e.g., at gas plant tailgate if the plant is grouped with the producing wells for FAS 121 purposes. Thus, incremental profits or losses generated by subsequent downstream activities and some risk-management activities would be excluded from the determination of future hydrocarbon prices for the impaired asset group.
3. **Costs.** Future cost projections should be management's best estimate of the future capital expenditures, operating costs, and

perhaps DR&A costs directly associated with the impaired asset group (see the chapter's prior discussion on consideration of DR&A costs). These costs should also have a high correlation with the future operating and capital expenditure assumptions management uses in its long-range budgeting process. In estimating future costs, it is appropriate to escalate current costs by anticipated inflation factors consistent with using oil and gas sales prices in nominal dollars.

4. **G&A Overhead.** The *1999 PricewaterhouseCoopers Survey of U.S. Petroleum Accounting Practices* found that 86 percent of respondents using successful efforts ignored overhead in determining expected future cash flow for FAS 121 purposes. Overhead costs should be considered to the extent that such costs directly relate to the operations of the impaired asset group (e.g., operating personnel and project support staff located in district offices). Corporate or home office overhead that does not directly relate to the impaired asset's activities should not be considered in the asset's future cost projections. Arguably, some home office overhead is necessary for using the asset. Such overhead might be viewed as what FAS 121 paragraph 6 calls "future cash outflows expected to be necessary" to obtain the future cash inflow generated by the asset. Indeed, some loans to E&P companies were substantially impaired when oil prices crashed in 1986 because the lenders failed to consider the heavy G&A costs to operate numerous small properties in order to generate cash flow to repay the loans.
5. **Income Taxes.** So-called income taxes in foreign jurisdictions should be evaluated as to whether they are more appropriately classified as royalties or production taxes that reduce future pre-tax cash flows.

DETERMINING FAIR VALUE

Paragraph 7 of FAS 121 states that the impairment loss associated with an asset group is "the amount by which the carrying amount of the asset exceeds the fair value of the asset." Paragraph 7 defines *fair value* as the "amount at which the asset could be bought or sold in a current transaction between willing parties." An asset's fair value is preferably indicated by quoted market prices in active markets, if available. Otherwise, fair value is based on the best information available in the circumstances, such as prices of similar assets and the results of valuation techniques.

Quoted market prices are not available for proved oil and gas properties. Fair value varies with expected future cash flow from the properties. Therefore, companies generally estimate bid prices and the ultimate purchase and sales prices of oil and gas properties using a discounted cash-flow analysis. A discounted cash-flow analysis takes various forms in which the cash flows and corresponding discount rates may reflect the following:

- Cash flows using nominal dollars (reflecting inflation) or real dollars (ignoring inflation).
- Tax expense as a separate cash outflow or adjusting the discount rate to reflect tax expense (see Chapter Thirty for further explanation).
- Risk-weighting the individual cash flow streams or discounting the net cash flow streams considering underlying risks.

Paragraph 7 of FAS 121 states that the estimate of fair value should be based on the best information available in the circumstances. Therefore, valuation techniques that are merely rough rules of thumb, such as value per reserve barrel, should not be used when a better approach, discounted cash-flow analysis, is available.

Paragraph 7 of FAS 121 states that expected future cash flows should be discounted using a rate commensurate with the risks involved. Paragraph 85 of FAS 121 states that "the Board does not believe that discounting expected future cash flows using a debt rate is an appropriate measure for determining the value of those assets." Accordingly, the discount rate determined for each impaired asset group should be based on the rate of return the market expects for similar types of assets. Factors such as the company's internal hurdle rate for return on capital expenditures should be considered in determining the discount rates.

It may be appropriate to separately risk adjust certain cash inflows and outflows based on the probability of their likelihood rather than indirectly adjusting for risk by modifying the discount rate(s). For example, if the probability associated with actually paying future DR&A costs is significantly different from the probability that hydrocarbon production will occur, or that the future sales prices will be realized, each cash flow stream might be appropriately risk-weighted.

Chapter Thirty further addresses how to determine fair value of proved oil and gas properties.

As noted on page 439, fair value and the amount of impairment are determined without regard to deferred income taxes or the amount of income taxes due (or saved) by the seller for the taxable gain (or loss) on selling the property at a value different from the property's tax basis. FAS 121 measurement of impairment differs in that respect from the full cost ceiling test which is designed to consider such taxes.

ASSETS TO BE DISPOSED OF

FAS 121 also provides guidance for the recognition and measurement of the impairment of long-lived assets to be disposed of for which the accounting is not prescribed by Accounting Principles Board Opinion No. 30, *Reporting the Results of Operations—Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions,* and related interpretations (*Discontinued Operations*) or other FASB statements.

Proved oil and gas properties which management has identified as being held for sale should be recorded at the lower of:

- cost or
- fair value less costs to sell.

These assets held for disposal should be distinguished from the company's other proved properties, either on the face of the balance sheet or in the notes to financial statements. There must be a plan to dispose of these assets. Generally, the expected disposal of assets held for sale should occur within one year of the date the company commits to a plan of disposal.

For assets to be disposed of, fair value is the expected future net realizable value from the sale discounted to the present value at the appraisal date. Fair value ignores estimated future oil and gas revenues and related operating expenses during the holding period prior to sale.[58] For example, if at December 31, 2000, a proposed sales contract calls for

[58]This determination of fair value less cost to sell is found in FASB member Robert Northcutt's dissenting remarks contained with FAS 121, "The only difference between the fair value less cost to sell measure and the net realizable value measure is the consideration of the time value of money. The fair value less cost to sell measure requires that the expected net proceeds be discounted." Net proceeds are sales proceeds less cost to sell. Mr. Northcutt's quoted

selling a property on March 1 for $1 million with selling costs of $100,000, the expected future net realizable value is $900,000. Assume that discounting the $900,000 gives a December 31, 2000 present value of $880,000. Fair value at December 31, 2000 is $880,000 for determining impairment. The additional value of production in January and February is ignored. The property's capitalized costs are not depreciated for January and February.

FAS 121 paragraph 16 provides that if the asset's fair value is measured by discounting expected future cash flows and if the sale is expected to occur beyond one year, then the cost to sell should also be discounted. This rule implies that in other circumstances the cost to sell is not discounted.[59]

Paragraph 16 also states that the assets identified as being held for sale should "not be depreciated (amortized) while they are being held for disposal." Accordingly, oil and gas revenues and related operating expenses from assets held for sale are recognized, but no corresponding DD&A is provided. This treatment is proper, since the carrying value of assets held for disposal will be recovered from their sale, not use. In instances in which there is a subsequent revision of the fair value less costs to sell, the carrying value of the assets held for sale should be adjusted to the new value, provided the new carrying value does not exceed the carrying value of such assets before the decision was made to dispose of them.

Here is an example to illustrate these concepts in applying FAS 121 to long-lived assets to be disposed of. An E&P company signed a letter of intent on February 15, 2000, to sell its Texas properties for $100 million less an estimated $5 million in operating cash flow through the expected closing date of September 28, 2000. Assume selling costs are $3 million. Then the expected sales proceeds are $95 million, and the net sales proceeds are $92 million. Assume that the E&P company has other E&P properties so that the sale of the Texas properties is not deemed to be discontinuance of a business segment covered by APB 30. Rather, FAS 121 applies, and the Texas properties are treated as long-lived assets to be disposed of.

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comments are consistent with the FAS 121 paragraph 16 requirement that assets held for sale (carried at the lower of cost or fair value less cost to sell) "not be depreciated (amortized) while they are held for disposal."

[59]Not discounting the cost to sell is a conservative, and generally insignificant, inconsistency with the preceding footnote's explanation of the term *fair value less cost to sell*.

At February 29, 2000, the properties are to be carried at the lower of cost or fair value less cost to sell. Assuming a four percent discount rate for six months as the time value of money, the expected $95 million in sales proceeds is discounted to a $91.35 million fair value at February 29, 2000. Fair value less undiscounted cost to sell equals $88.35 million. If the properties' total carrying value at February 29 was $90 million, the E&P company would write-down the assets' carrying value to $88.35 million and not depreciate the $88.35 million over the six-month holding period prior to sale. If the total carrying value were $85 million, no write-down would occur, and no depreciation would be taken during the holding period.

Disclosure of the impairment losses on assets held for sale is similar to the disclosures discussed above for assets held and used and the following additional disclosures:

1. Facts and circumstances leading to the expected disposal,
2. Expected disposal date and carrying amount,
3. Any gains or losses resulting from re-measurement of the assets,
4. Results of operations included in the income statement, if such results can be identified.

APPLICABILITY TO FULL COST COMPANIES

This chapter's overview noted that full cost companies use the full cost ceiling provisions found in Reg. S-X Rule 4-10. That is, companies subject to SEC regulation and privately held full cost companies use the full cost ceiling test as specified in Reg. S-X Rule 4-10 and likely ignore the FAS 121 impairment tests for the full cost pool as explained below.

The SEC staff have issued comment letters calling for disclosure by full cost companies that the full cost ceiling test is used for proved oil and gas property in lieu of FAS 121. FASB staff have recommended that privately held companies using full cost follow the guidance for other full cost companies, presumably the full cost ceiling test used by publicly held full cost companies.[60] The FASB staff's recommendation is consistent with the concept that full cost companies subject to Reg. S-X Rule 4-10(c) full cost accounting rules effectively establish the generally accepted practices for full cost, i.e., the public companies' practices become the known norm to be followed by the privately held companies.

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[60]Based on minutes of the FASB meeting of September 14, 1994.

One Asset per Country-wide Cost Pool

In theory, publicly held full cost companies are subject to both the FAS 121 impairment rules and Reg. S-X Rule 4-10(c) ceiling-test. However, the ceiling effectively limits aggregate costs to a level so far below undiscounted expected future cash flow that FAS 121 would rarely apply. A notable exception is when year-end pricing (used in the ceiling test) substantially exceeds expected pricing (used for FAS 121 impairment accounting).

The cost pool (i.e., a cost aggregation of successful and unsuccessful exploration activities) serves under full cost theory as a single asset—a probable future economic benefit indicated by proved reserves obtained by the company as a result of all prior exploration and development activity in a given country. It is subject to a single amortization per period and is not readily divisible into smaller assets.

Although the FASB "did not endorse the view of many respondents that oil and gas companies should group their assets . . . on a country-by-country basis" (FAS 121, Paragraph 102), it is impractical, inconsistent with full cost accounting theory, and not literally required by FAS 121 for the country-wide cost pool asset, if it is a single asset, to be split up into pieces at the lowest level of largely independent identifiable cash flows. In the SEC codification of financial reporting releases, Section 406.01.c.i, the SEC notes that once costs are included in the full cost pool amortization base, "they lose their identity for all future accounting purposes."

So, effectively, no FAS 121 impairment is recognized unless the capitalized aggregate costs exceed the aggregate expected future cash flows by country. Before that can happen, the S-X ceiling test using *discounted* cash flows would trigger a write-down to keep capitalized costs from exceeding undiscounted expected future cash flows except in the unusual case when year-end pricing for the ceiling test substantially exceeded expected pricing.

Disregarding the Cost Pool as a Single Asset

Even if the full cost pool were to be treated as a grouping of assets, with each field representing an appropriate grouping of assets, then the ceiling test using discounted cash flow would still minimize, if not eliminate, any write-downs for impairments under FAS 121.

Every quarter the full cost company would apply the ceiling test. Under FAS 121, the company would also estimate the fair value of its holdings in each field and allocate the country-wide amortization base among the fields, based on relative fair value, to see if the net book value allocated to a field exceeded the corresponding undiscounted expected future cash flow. Fields with relatively little expected future cash flow would have a relatively low fair value and be allocated relatively little net book value. Hence, to not view the cost pool as a single asset for applying FAS 121 would rarely change the ultimate impairment, and such rare changes would likely be insignificant.

FAS 121 HAS NO EFFECT ON THE DD&A METHOD OR ON COMPUTING THE FAS 69 STANDARDIZED MEASURE

In FAS 121 expected future cash flows use expected prices, expected cost rates, and expected future production. As previously explained in this chapter, expected future production might include risk-weighted probable and possible reserves. FAS 19 successful efforts and S-X full cost accounting pronouncements specifically require that DD&A be based on proved reserves. Proved reserves, by definition, are only those reserves recoverable with reasonable certainty using prices and cost rates as of the date the reserve estimate applies. FAS 69 requires that the standardized measure (addressed in Chapter Twenty-Nine) be based on proved reserves and year-end prices and costs rates, not on expected production, prices, and cost rates.

The method by which a company groups costs for DD&A amortization (such as by property) is independent of the way assets are to be grouped for FAS 121 impairment tests (such as by field). In other words, cost aggregation for calculating an amortization base under full cost or under successful efforts is not a function of asset grouping for FAS 121.

Chapter Nineteen

THE FULL COST ACCOUNTING METHOD

Prior to the late 1950s, essentially all oil and gas producing companies used some variation of the successful efforts method of accounting that has been described in previous chapters of this book. However, at that time a new approach to accounting for exploration, acquisition, and development costs was developed—the full cost method. Under this concept, all costs incurred in acquiring, exploring, and developing properties within a large geopolitical or geographical cost center are capitalized and amortized as the reserves in that cost center are produced.

The full cost accounting method regards all costs of acquisition, exploration, and development activities as necessary for the ultimate production of reserves. All of those costs are incurred with the knowledge that many of them relate to activities that do not directly result in finding and developing reserves. However, the company expects that the benefits obtained from the prospects that do prove successful, together with benefits from past discoveries, will be adequate to recover the costs of all activities, both successful and unsuccessful, and to yield a profit. Thus, all costs incurred in all those activities are regarded as integral to the acquisition, discovery, and development of whatever reserves ultimately result from the efforts as a whole and are thereby associated with the company's proved reserves. Establishing a direct cause-and-effect relationship between costs incurred and specific reserves discovered is not relevant to the full cost concept.

In the 1960s many publicly held oil and gas companies, especially small new companies, adopted the full cost method, so that by the mid-1970s, and continuing today, nearly one-half of the publicly held companies were using full cost.[61] Figure 19-1 (identical to Figure 4-2) summarizes the major full cost accounting rules explained in this chapter.

Although in FAS 19 the FASB rejected full cost as an acceptable accounting method, the SEC concluded in August 1978 in ASR 253 that the successful efforts method promulgated in FAS 19 should not be the only acceptable method and announced that a full cost method to be

[61]In recent years some companies (especially larger ones) that previously used the full cost method have changed to the successful efforts method. It appears, however, that nearly half of the publicly held companies used full cost in 1999.

developed by the SEC could also be used by publicly held companies in reports filed with the SEC. In ASR 258, issued in December 1978, the SEC announced adoption of final rules for companies electing to use the full cost method. The initial rules were modified in 1983 and 1984. Those modified rules, found in Reg. S-X Rule 4-10 (reproduced in Appendix 1 of this book) are examined in the remainder of this chapter. The rules center on the nature of the cost center, the costs to be capitalized, the costs to be amortized, amortization methods, and computation of a *ceiling* on capitalized costs.

In response to ASR 258's allowance of full cost accounting for companies filing with the SEC, the FASB issued FAS 25 in February 1979. It rescinded the FAS 19 requirement to use the successful efforts accounting method specified in FAS 19. However, FAS 25 Paragraph 4, provides that because FAS 19 was issued, the specified successful efforts accounting method remains *preferable* in justifying a change to that method. Accordingly, the SEC does not require the independent auditor's letter of preferability for an accounting change to the FAS 19 successful efforts accounting method, as noted in SEC Staff Accounting Bulletin Topic 12C, Item 1, reproduced on page 2-11 of Appendix 2. The SEC does require the letter for a change to full cost accounting.

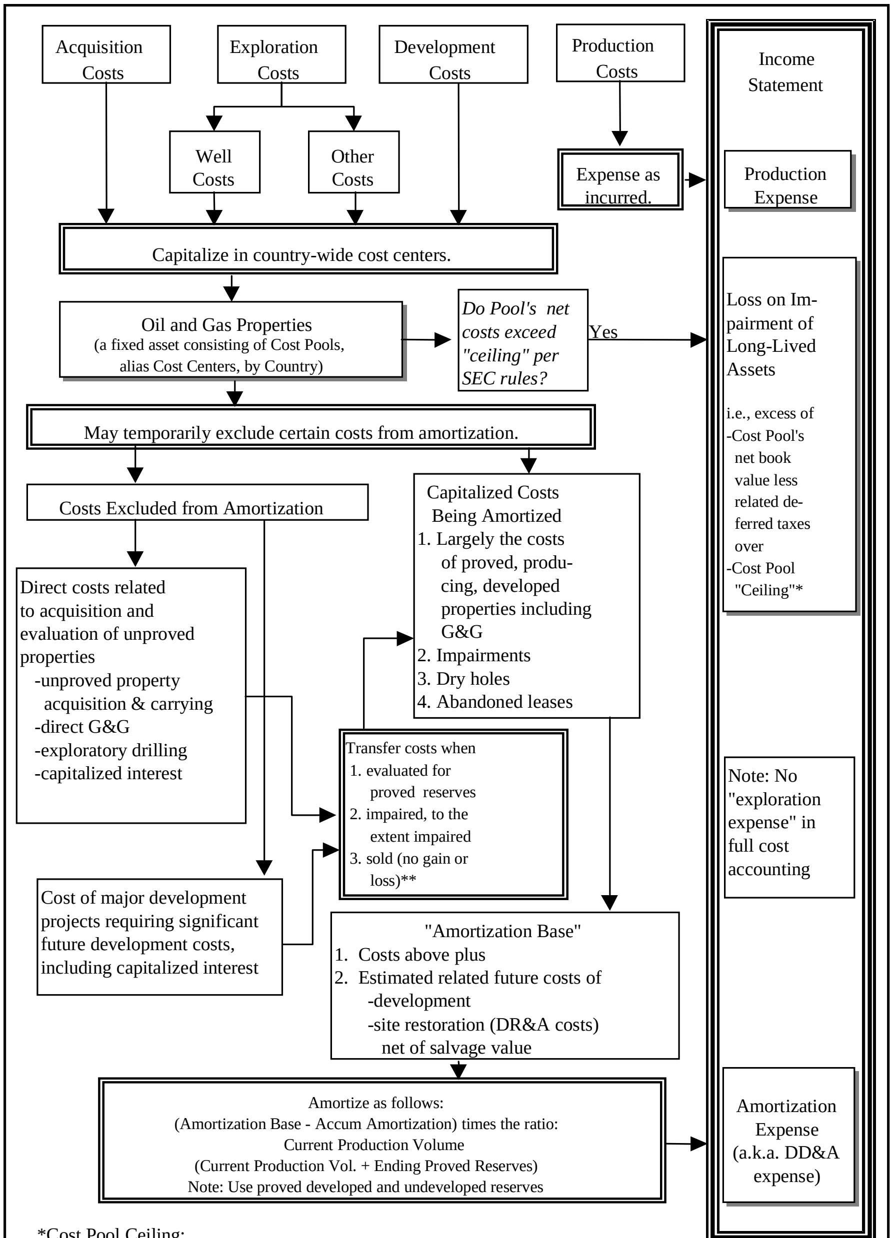
THE COST CENTER

Under the SEC's rules, cost centers are to be established on a country-by-country basis. A rigid interpretation of this rule would thus prohibit the combining or grouping of countries in a geographical area. For example, it would be improper to combine a company's North Sea operations in the Norwegian and British territorial areas. Reg. S-X Rule 4-10(c)(6)(ii) provides a rare exception to the country-wide cost center:

> [S]ignificant purchases of production payments or properties with lives substantially shorter than the composite productive life of the cost center shall be accounted for separately.

See the full cost accounting section in Chapter Twenty-Two for further discussion of this exception.

Figure 19-1: Full Cost Accounting for Costs



*Cost Pool Ceiling:

(a) a present value of projected future cash flow from proved reserves,

(b) plus costs excluded from amortization,

(c) plus the lower of cost or fair value of unproved properties in amortization base,

(d) less estimated related income tax effects, i.e., (1) the present value of income taxes on taxable income relating to proved reserves' future cash flow and (2) income taxes from hypothetically selling immediately the unproved properties and unevaluated projects at the values in (b) and (c) above

**No gain or loss unless otherwise the ratio of cost to proved reserves would significantly change.

INVENTORY OF PROPERTIES FOR PROMOTION OR SALE

Reg. S-X Rule 4-10 makes no reference to the possibility that an oil and gas producing company may also be engaged in the *lease brokerage* business. However, the SEC's Staff Accounting Bulletin No. 47 referred to the *two lines of business concept,* and many accountants argue that an oil and gas company may participate in two distinct businesses, oil and gas producing activities and lease brokerage activities, by acquiring some unproved properties for the specific purpose of drilling for oil or gas and acquiring other properties for the specific purpose of *promoting* them, usually through the transfer of such properties to limited partnerships, with funds to pay for drilling and development being provided by limited partners.

SAB 47 originally indicated that the *two lines of business* approach was acceptable and that a property might be deemed to have been acquired for promotional activities and included in an inventory of properties held for such purposes *if such distinction was made at the time of acquisition.*

In May 1984, the SEC revoked this portion of SAB 47 and revised Reg. S-X Rule 4-10 to provide that essentially all sales of properties or transfers of unproved properties to partnerships, funds, etc., represent adjustments of the full cost pool and that no gain or loss shall be recognized on such conveyances. Thus, costs of all mineral properties owned by a full cost company, including those acquired for resale or promotion, are treated alike and should be included in a single, country-wide cost center.

COSTS TO BE CAPITALIZED

S-X Rule 4-10(c)(2) specifies the costs to be capitalized under full cost:

> *Costs to be capitalized.* All costs associated with property acquisition, exploration, and development activities (as defined in paragraph (a) of this section) shall be capitalized within the appropriate cost center. Any internal costs that are capitalized shall be limited to those costs that can be directly identified with acquisition, exploration, and development activities undertaken by the reporting entity for its own account, and shall not include any costs related to production, general corporate overhead, or similar activities.

Under these rules, all geological and geophysical costs, carrying costs such as delay rentals and maintenance of land and lease records, dry-hole and bottom-hole contributions, costs of exploratory wells (both dry and successful), costs of stratigraphic tests wells, costs of acquiring properties, and all development costs are capitalized. As pointed out in the citation above, only those overhead costs related directly to exploration, acquisition, and development activities should be capitalized. A special problem arises in determining the amount of interest to be capitalized by full cost companies. This problem is discussed later in this chapter. Even after leases are surrendered or abandoned, their costs remain a part of the capitalized costs of the cost center, as do the costs of dry holes and other unsuccessful exploration.

Since all costs incurred in each country are capitalized and treated as applicable to all mineral assets within that country, individual properties and assets conceptually lose their identities. A single Oil and Gas Assets account (or account with a similar title) for each country could be used to accumulate the costs in that country. For example, a company with operations in the U.S. (onshore and offshore), Canada, and Norway would maintain accounts in three cost centers:

Oil and Gas Assets—United States
Oil and Gas Assets—Canada
Oil and Gas Assets—Norway

Even though all oil and gas assets in a cost center could be lumped into a single account, detailed records of acquisition costs, drilling and development costs, etc., must be maintained for federal income tax and other regulatory purposes. In addition, it is possible to temporarily exclude certain *unevaluated* costs from the amortization base. Therefore, companies using the full cost method must effectively maintain subledgers of cost records of individual unproved properties and individual proved properties in much the same way as described in earlier chapters for companies using the successful efforts method. In addition, the method of accounting used does not alter the procedures necessary for management and internal control of operations. Basic accounting procedures such as the use of an AFE are not likely to be affected by the choice of successful efforts accounting or full cost accounting.

For these reasons, most companies use general ledger accounts very similar to those used in successful efforts accounting, as shown in this book's illustrative chart of accounts in Appendix 5.

AMORTIZATION OF CAPITALIZED COSTS

The procedures to be followed in amortizing capitalized costs under the full cost method differ significantly from those used under successful efforts accounting. Both the reserves to be used and the costs to be amortized in the unit-of-production amortization calculation differ.

RESERVES TO BE USED IN THE AMORTIZATION CALCULATION

All capitalized costs within a cost center (a country) are to be amortized on the unit-of-production basis, using total *proved* oil and gas reserves in the cost center. (However, certain unevaluated costs may be temporarily excluded from amortization.) As discussed subsequently, oil and gas reserves are to be converted to a common unit-of-measure based on energy content or, in limited cases, based on current and future gross revenues.

COSTS TO BE AMORTIZED

Regulation S-X Rule 4-10(c)(3)(i) contains the basic description of costs to be amortized:

> Costs to be amortized shall include (A) all capitalized costs, less accumulated amortization, other than the [costs of acquiring and evaluating unproved property, as explained on the next page]; (B) the estimated future expenditures (based on current costs) to be incurred in developing proved reserves; and (C) estimated dismantlement and abandonment costs, net of estimated salvage values.

A feature of full cost is that *all* capitalized costs relating to oil and gas assets, other than specifically excluded costs (discussed below), are to enter into the amortization computation at the time they are incurred. Another distinctive feature of full cost amortization is the general inclusion in amortizable costs of *future expenditures* to be incurred in developing the proved reserves that are included in the amortization calculation. The inclusion of estimated future development costs, based on current cost levels, is necessary because all proved reserves are included in the calculation, including those not yet developed. Omission of future development costs would result in a mismatching of costs applicable to the reserves used in the calculation. Dismantlement and abandonment costs must be considered in the same manner as they are under successful efforts accounting, described in Chapter Twenty.

EXCLUSIONS FROM THE AMORTIZATION POOL

There are two exceptions to the general rule that all capitalized costs in the cost center must be included in the amortization computation as soon as the costs are incurred. These exceptions are provided in Reg. S-X Rule 4-10(c)(3)(ii), as amended in 1983. The costs involved are those related to unevaluated properties and the costs of major development projects expected to require significant future costs.

Costs Related to Unevaluated Properties

The first permitted exclusion from amortization are the costs of acquisition and exploration directly related to unevaluated properties. Paragraph (c)(3)(ii)(A), as amended in 1983, provides that:

> all costs directly associated with the acquisition and evaluation of unproved properties may be excluded from the amortization computation until it is determined whether or not proved reserves can be assigned to the properties, subject to the following conditions: (1) Until such a determination is made, the properties shall be assessed at least annually to ascertain whether impairment has occurred. Unevaluated properties whose costs are individually significant shall be assessed individually. Where it is not practicable to individually assess the amount of impairment of properties for which costs are not individually significant, such properties may be grouped for purposes of assessing impairment. Impairment may be estimated by applying factors based on historical experience and other data such as primary lease terms of the properties, average holding periods of unproved properties, and geographic and geologic data, to groupings of individually insignificant properties and projects. The amount of impairment assessed under either of these methods shall be added to the costs to be amortized. (2) The costs of drilling exploratory dry holes shall be included in the amortization base immediately upon determination that the well is dry. (3) If geological and geophysical costs cannot be directly associated with specific unevaluated properties, they shall be included in the amortization base as incurred. Upon complete evaluation of a property, the total remaining excluded cost (net of any impairment) shall be included in the full cost amortization base.

The exclusion refers to "all costs directly associated with acquisition and evaluation of unproved properties." Although carrying costs are not specified in that description, SEC Financial Reporting Release 14 (which provided for the exclusion) seems reasonably clear in allowing carrying costs to be included in the costs excluded from amortization and subject to annual impairment assessments.

Note that the rules given above for determining the *impairment* of unevaluated properties and related costs are very similar to those given in Chapter Seven for determining impairment of unproved properties by successful efforts companies. In many instances the SEC has adapted the rules for successful efforts accounting to specific problems in applying the full cost concept.

This amortization exclusion is permitted in order to avoid distortion in the amortization per unit that could result if the cost of unevaluated properties with no proved reserves attributed to them were included in the amortization base. In other words, it represents an effort to match proved reserves in the country-wide cost center with their associated costs, including unsuccessful exploration costs.

The following calculation of a hypothetical cost center's amortization base illustrates the exclusion of unevaluated costs from the amortization calculation:

Capitalized costs as of period end		$140,000,000
Less amortization in prior periods		(30,000,000)
Net book value prior to current amortization		110,000,000
Add estimated future development costs		10,000,000
Total		120,000,000
Less costs related to unevaluated properties:		
Cost	$25,000,000	
Less cumulative impairments	(5,000,000)	(20,000,000)
Amortization Base		$100,000,000

Unusually Significant Development Projects

The second permissible exclusion of capitalized costs from the amortization pool is provided in Reg. S-X Rule 4-10(c)(3)(ii)(B), as revised in 1983:

> (B) certain costs may be excluded from amortization when incurred in connection with major development projects expected to entail significant costs to ascertain the quantities of proved reserves attributable to the properties under development (e.g., the installation of an offshore drilling platform from which development wells are to be drilled, the installation of improved recovery programs, and similar major projects undertaken in the expectation of significant additions to proved reserves). The amounts which may be excluded are applicable portions of (*1*) the costs that relate to the major development project and have not previously been included in the amortization base, and (*2*) the estimated future expenditures associated with the development project. The excluded portion of any common costs associated with the development project should be based, as is most appropriate in the circumstances, on a comparison of either (i) existing proved reserves to total proved reserves expected to be established upon completion of the project, or (ii) the number of wells to which proved reserves have been assigned and the total number of wells expected to be drilled. Such costs may be excluded from costs to be amortized until the earlier determination of whether additional reserves are proved or impairment occurs.
>
> (C) excluded costs and the proved reserves related to such costs shall be transferred into the amortization base on an ongoing (well-by-well or property-by-property) basis as the project is evaluated and proved reserves established or impairment determined. Once proved reserves are established, there is no further justification for continued exclusion from the full cost amortization base even if other factors prevent immediate production or marketing.

To illustrate the exclusion of development costs from the amortization calculation, assume that capitalized costs of a discovery well, two *evaluation* wells, and a platform related to a major offshore project total $36,000,000. Two producing wells have been drilled from the platform at a cost of $2,500,000 per well, and eight more wells, expected to cost $2,500,000 each, are expected to be drilled to formations containing an estimated 8,400,000 barrels of probable reserves. It is estimated that a total of 10,000,000 barrels may finally be proved, although only 1,600,000 have been proved by the two development wells. In the computation of amortization for the year, the reserves not yet proved are to be omitted from the proved reserves used in the amortization calculation. That portion of the $36,000,000 of common costs that is deemed to be related to the excluded reserves may be appropriately excluded from the amortization base. Shown below are the calculations of the excluded portion using an allocation of common costs by well and an allocation by reserves:

Excluded costs using an allocation by well:	
Direct costs of the eight wells at $2.5 million each	$20,000,000
Plus common costs of $36 million x 8 wells / 10 wells	28,800,000
	$48,800,000
Excluded costs using an allocation by reserves:	
Direct costs of the eight wells at $2.5 million each	$20,000,000
Plus common costs of $36 million x 84%*	30,240,000
	$50,240,000

*8.4 million bbls / 10.4 million bbls.

Disclosure of Exclusions

Reg. S-X Rule 4-10(c)(7)(ii) provides several required disclosures for the costs excluded from the amortization base. An entity is required to state separately on the face of the balance sheet the aggregate capitalized costs of unproved properties and major development projects that are excluded from capitalized costs being amortized. In addition, the notes to the financial statements must include a description of the current status of the significant properties or projects involved, including the anticipated timing of inclusion of the costs in the amortization computation. A table must be presented showing by category of cost (acquisition, exploration, development, and capitalized interest) (1) the total costs excluded as of the most recent fiscal year and (2) the amount of such excluded costs incurred (a) in each of the three most recent fiscal years and (b) in the aggregate for any earlier fiscal years in which the costs were incurred.

The excluded costs do not have to be disclosed by cost center, nor does the financial note need to provide the status of all properties and projects with excluded costs. For example, the balance sheet might show:

Oil and gas property and equipment:	
Proved properties	$40,000,000
Unproved properties and development costs not being amortized	10,000,000
	50,000,000
Less accumulated amortization	(8,000,000)
	$42,000,000

The financial statement note might read as follows:

Costs not being amortized. The company excludes from amortization the cost of unproved properties, the cost of exploratory wells in progress, and major development projects in progress. Oil and gas property and equipment costs not being amortized as of December 31, 2000, are as follows (in millions), by the year in which such costs were incurred:

	Total	2000	1999	1998	Prior
Acquisition costs	$ 5.0	$2.0	$2.0	$0.6	$0.4
Exploration costs	1.0	0.8	0.1	0.1	-
Development costs	3.7	3.7	-	-	-
Capitalized interest	0.3	0.3	-	-	-
	$10.0	$6.8	$2.1	$0.7	$0.4

The excluded costs include (1) $5,100,000 for the Some Day offshore field expected to be included in the amortization base in 2001 and (2) $2,300,000 in the unproved, unevaluated Brittany Ranch lease expected to be evaluated in 2001.

UNIT-OF-PRODUCTION AMORTIZATION

Generally, amortization of the capitalized costs of oil and gas assets is to be computed on the basis of physical units, with oil and gas converted to a common unit-of-measure on the basis of their relative energy content (with a single exception to be discussed later). Conversion to an equivalent barrel or mcf is the same as illustrated in Chapter Seventeen.

The full cost unit-of-production amortization formula is similar to the formula given at the end of Chapter Seventeen, except as follows:

- The cost center is countrywide, and
- Amortization uses total proved reserves and adds to the amortization base any related future development costs.

The full cost amortization formula may be expressed as follows:

- Amortization expense = B x S/(S+R), where:
  - B = the amortization base, defined below;
  - S = the volume sold during the period (boe, mcfe, or the volume of the dominant hydrocarbon); and
  - R = the volume of total proved reserves at period's end.

- B, the amortization base, = C-A+D-V-E+F, where:
  - C = incurred capitalized costs of acquisition, exploration, and development activities;
  - A = the prior accumulated amortization;
  - D = the estimated undiscounted future DR&A costs (but see Chapter Twenty for proposed new standards);
  - V = the estimated undiscounted future salvage value of the lease equipment (but see Chapter Twenty);
  - E = the *excluded* capitalized unproved property costs and certain capitalized development costs [i.e., excluded from the amortization base as allowed in Reg. S-X Rule 4-10(c)(3)(ii)]; and
  - F = the undiscounted estimated future expenditures (based on current cost rates) to be incurred in developing proved reserves.

Amortization expense is thus [C-A+D-V-E+F] x S/(S+R).

To illustrate this computation, assume that the following data apply to Public Company's oil and gas assets in a given country:

C	:	Capitalized costs for the country	$260,000,000
Less	A :	Accumulated amortization	(48,000,000)
Plus	D :	Estimated dismantlement (DR&A) costs	10,000,000
Less	V :	Estimated equipment salvage value	(8,000,000)
Less	E :	Costs excluded from amortization	(12,000,000)
Plus	F :	Estimated future development costs	14,000,000
Equals	B :	Amortization base	216,000,000
Times	S :	Units sold in the year	x 4,000,000 boe
Divided by (S+R) where R (proved reserves at year end) equals 32,000,000 boe			÷36,000,000 boe
Equals the current year's amortization			$ 24,000,000

Notice that the formula adds the period's units sold (S) to reserves at the end of the amortization period (R) to calculate the best current estimate of proved reserves as of the beginning of the period (S+R) to correspond to the amortization base (B) prior to the current period's amortization.

Shrinkage

As noted in Chapter Seventeen, units sold (S) could arguably be replaced with units produced, but the two volumes are nearly equal over a three-month or twelve-month period. In some instances, units sold are significantly less than units produced; the difference being called *shrinkage*. Shrinkage may arise from natural gas used on the lease, gas volumes lost in processing for extraction of NGL, removal of impurities and BS&W, and even theft or pipeline leaks. Where shrinkage is significant, the amortization calculation should use units sold (S) and proved reserves (R) that are both before shrinkage or both after shrinkage so that costs will be reasonably allocated over the productive life of the reserves.

GROSS REVENUE METHOD OF AMORTIZING COSTS

Although the conversion of oil and gas into a common measure must generally be based on their relative energy content, Paragraph (c)(3)(iii) of Reg. S-X Rule 4-10 provides that if, because of oil or gas price regulation, economic circumstance indicates that units of revenue is a more appropriate basis for computing amortization, that basis may be used. Recall from Chapters Three and Twelve that oil and gas price regulations had ended in the United States by 1993. SAB Topic 12F clarified that the gross revenue method may still be used even when production is not subject to price regulation. Topic 12F states that this method may be more appropriate

> whenever oil and gas sales prices are disproportionate to their relative energy content to the extent that the use of the unit-of-production method would result in an improper matching of the costs of oil and gas production against the related revenue received. The method should be consistently applied and appropriately disclosed within the financial statements.

Historically oil prices relative to gas prices are disproportionate to their relative energy content. The ratio of oil price to gas price varies. At times in the past, the wellhead price of an oil barrel approximated ten times the wellhead price of an mcf of natural gas, whereas an oil barrel has only six times the energy of an mcf of gas. Particularly when the price ratio at year end differed significantly from the average price ratio for the year, the gross revenue method could provide amortization expense significantly different from that calculated by the unit-of-production method.

Reg. S-X Rule 4-10 provides that unit-of-revenue amortization shall be computed on the basis of current gross revenues from production in relation to future gross revenues, based on current prices, from estimated production of proved oil and gas reserves. As used here, the term *gross revenue* means revenue net of royalty and net profit obligations but not reduced by production costs. Changes in existing prices are to be considered only where they are provided by contractual arrangements.

To illustrate the computation of the gross revenue method of amortization, assume the same facts as in the immediately preceding example. In addition, assume the following additional facts:

Year's average price for the 4,000,000 boe produced	\$16 per bbl
Year-end price per barrel of oil equivalent	\$20 per bbl

B (the amortization base)	\$216,000,000
Times S (the current year revenue, \$16 x 4 mmboe)	x \$ 64,000,000
Divided by (S+R), where R = \$20 x 32,000,000 boe	÷ \$704,000,000
Equals the current year's amortization	\$ 19,636,364

Paragraph (c)(3)(iii) also states, "The effect of a significant price increase during the year on estimated future gross revenues shall be reflected in the amortization provision only for the period after the price increase occurs." This rather vague statement has been interpreted by some to suggest that the effects on future revenues of insignificant price changes may be considered in computing amortization in the interim period in which the price change occurs but that the effects of a significant price change on future revenues should be considered only in the next interim (quarterly) period. That literal interpretation seems inconsistent with the concept of using prices at the end of the period to determine as of that date proved reserves, future net revenues under Reg. S-X Rule 4-10(c)(4)(i), and the standardized measure disclosure under FAS 69. SAB

Topic 12F on the gross revenue method does not address this interpretation.

Under the literal interpretation, the basic accounting period for amortization is the interim period. Although no guidelines are given for determining what is significant, it would appear that unless the increase in price of oil or gas is sufficient to increase overall future revenue from oil and gas reserves by a material amount (perhaps more than five percent), the increase should not be deemed significant.

For example, assume that quarterly financial statements are issued on a calendar quarter basis. On January 1, 2000, a company's estimated reserves and unamortized costs were as follows:

Oil reserves	10,000,000	bbls
Gas reserves	200,000,000	mcf
Unamortized costs	$360,000,000	
Oil price	$20	per barrel
Gas price	$2	per mcf

Production for the first quarter was 250,000 barrels of oil sold for $5,000,000, and 5,000,000 mcf of gas sold for $10,000,000. In April, gas prices increased from $2.00 per mcf to $2.10 per mcf. During the second quarter, 150,000 barrels of oil were sold for $3,000,000, and 4,000,000 mcf of gas were sold for $8,400,000.

The company is using the gross revenue method of amortization. In computing amortization for the first quarter of the year, the increase in gas price from $2.00 to $2.10 in April would be ignored because the increase was not in the first quarter. Thus, amortization for the first quarter would be $9,000,000, computed as $360,000,000 unamortized cost times the ratio of $15,000,000 of first quarter revenues divided by $600,000,000 of future revenues at the beginning of the quarter. The first-quarter amortization reduces unamortized costs to $351,000,000.

In computing amortization for the second quarter, it would appear permissible (but not mandatory) to consider the ten cent gas price increase during the quarter in computing end-of-quarter future revenues because the increase is not significant. If the price increase is considered in computing amortization for the second quarter, the amount would be $6,619,355, computed as $351,000,000 unamortized cost times the ratio of $11,400,000 in second-quarter revenues divided by $604,500,000 computed as follows:

Reserve revenues at the second quarter's end (R):		
Oil: \$20/bbl x 9,600,000 bbls	=	\$192,000,000
Gas: \$2.10/mcf x 191,000,000 mcf	=	401,100,000
Second-quarter revenues (S)	=	11,400,000
Total (R+S)		\$604,500,000

Assume that a further increase in gas prices occurred in August 2000 so that on September 30, 2000, the average price per mcf was \$2.40. This increase represents a significant increase in prices; therefore, in computing amortization it should not be considered until the following quarter. During the third and fourth quarters, there were no changes in estimates of quantities of proved reserves, and the revenues were as follows:

Third quarter:	
Oil 200,000 bbls	\$ 4,000,000
Gas 5,000,000 mcf	\$11,000,000
Fourth quarter:	
Oil 150,000 bbls	\$ 3,000,000
Gas 4,000,000 mcf	\$ 9,600,000

Amortization for the third quarter is \$8,702,341, computed as \$344,380,645 unamortized cost times the ratio of \$15,000,000 in third-quarter revenue divided by \$593,600,000 computed as follows:

Reserve revenues at the third quarter's end (R):		
Oil: \$20/bbl x 9,400,000 bbls	=	\$188,000,000
Gas: \$2.10/mcf x 186,000,000 mcf	=	390,600,000
Third-quarter revenues (S)	=	15,000,000
Total (R+S)		\$593,600,000

In the fourth quarter, the period following the significant price increase, the new higher price may be considered in determining future revenues. Fourth-quarter amortization (assuming no change in reserve estimates) would be \$6,667,003, i.e., the \$335,678,304 unamortized cost times the ratio of \$12,600,000 divided by \$634,400,000, computed as follows:

Reserve revenues at the fourth quarter's end (R):		
Oil: $20/bbl x 9,250,000 bbls	=	$185,000,000
Gas: $2.40/mcf x 182,000,000 mcf	=	436,800,000
Fourth-quarter revenues (S)	=	12,600,000
Total (R+S)		$634,400,000

OTHER ASPECTS OF AMORTIZATION

Reg. S-X Rule 4-10(c)(3)(v) provides that the amortization "shall be made on a consolidated basis, including investees accounted for on a proportionate consolidation basis. Investees accounted for on the equity method shall be treated separately."

Reg. S-X Rule 4-10(c)(3)(iv) permits depreciation of natural gas processing plants by a method other than unit-of-production. Presumably this exception could apply, for example, for a processing plant treating not only the plant owner's gas but also, on a contract basis, gas belonging to others.

Reg. S-X Rule 4-10(c)(6)(ii) states that "purchases of proved reserves of oil and gas in place ordinarily are to be accounted for as additions to the capitalized costs in the cost center; however, significant purchases of production payments or proved properties with lives substantially shorter than the composite productive life of the cost center shall be accounted for separately."

Separate accounting of significant acquired production payments and short-lived properties usually increases the next year’s total DD&A. Consider the following example:

Properties	Cost	Production	Opening Reserves	DD&A
Existing	$10 million	200,000 bbl	2,000,000 bbl	$1.0 million
Purchased	5 million	100,000 bbl	500,000 bbl	1.0 million
Aggregate	$15 million	300,000 bbl	2,500,000 bbl	$1.8 million

For the example above, separate accounting gives a combined DD&A of $2 million. Aggregation gives a combined DD&A of $1.8 million.

In this example, the purchased property’s cost is 33% of the aggregate cost, and its life is half that of the existing properties’ average, yet the change in the first year’s total DD&A is only an 11% increase. Is the purchased property “significant” and does it have a “substantially shorter” life? There is no direct guidance in defining such terms. However, the SEC did provide guidance on significance in two closely related situations:

- The SEC has expressed that a full cost center's individually significant unproved properties under S-X Rule 4-10(c)(3)(1) would generally have costs of more than 10% of the cost center's net book value (see this book's App. 1-9).
- S-X Rule 4-10(c)(6)(i) calls for gain/loss recognition on the sale (not purchase) of property from the full cost pool when deferring the gain or loss would "significantly" alter the cost pool's amortization rate. Section (c)(6)(i) adds that significant alteration would not ordinarily be expected to occur for sales involving less than 25 percent of reserves in the full cost center. Chapter Twenty-One's discussion of this statement suggests that an alteration exceeding 10% is significant.

Such guidance and discussion on what constitutes significant unproved property and significant alteration would indicate that a property purchase need not be accounted for separately if such accounting would not change the combined DD&A expense by more than 10% immediately following the acquisition. In applying the full cost method, there should be a reluctance to create multiple cost centers within a country. Nevertheless, application of the SEC rule requires judgment for the particular circumstances.

INTEREST CAPITALIZATION

In Chapter Nine the FASB's requirements in FAS 34 for capitalization of interest during the *construction period* were examined. Interest is not to be capitalized on assets "that are in use or ready for their intended use in the earning activities of the business."

FASB Interpretation No. 33 clarified the interest capitalization rules for oil and gas producers using the full cost method. In that interpretation, the FASB concluded that full cost companies should capitalize interest only on assets that have been excluded from the full cost amortization pool. Assets being amortized are deemed to relate to reserves being produced and, thus, to constitute assets being used in the earnings process; hence, interest related to those assets cannot be capitalized. Capitalized interest becomes a part of the cost of the related properties or projects and will be subject to amortization when the costs of the assets are transferred to the amortization pool.

LIMITATION ON CAPITALIZED COSTS

One of the principal criticisms of full cost is that the capitalization of such costs as dry holes, exploration costs, and surrendered leases creates a danger that unamortized capitalized costs in a cost center may exceed the underlying value of oil and gas assets in that cost center. This possibility led the SEC to establish a *cost ceiling* for each cost center.

Repeated informal SEC staff interpretations indicate that the ceiling test is to be performed quarterly as of the end of the fiscal quarter. If the cost center's unamortized capitalized costs, less related deferred income taxes, exceed the *ceiling*, the net capitalized costs must be written down to the ceiling, with a corresponding charge against income as of that balance sheet date. The write-down may not be reversed in a subsequent reporting period.

The ceiling calculation is somewhat complicated and as a practical matter may be difficult to compute in some cases. The details are enumerated in Reg. S-X Rule 4-10(c)(4) below and clarified in SAB 47 as found in SAB Topic 12D.

> *Reg. S-X Rule 4-10(c)(4): "Limitation on capitalized costs:* (i) For each cost center, capitalized costs, less accumulated amortization and related deferred income taxes, shall not exceed an amount (the cost center ceiling) equal to the sum of: (A) the present value of estimated future net revenues computed by applying current prices of oil and gas reserves (with consideration of price changes only to the extent provided by contractual arrangements) to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet presented, less estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves computed using a discount factor of ten percent and assuming continuation of existing economic conditions; plus (B) the cost of properties not being amortized pursuant to paragraph (c)(3)(ii) of this section; plus (C) the lower of cost or estimated fair value of unproven properties included in the costs being amortized; less (D) income tax effects related to differences between the book and tax basis of the properties referred

to in paragraphs (c)(4)(i)(B) and (C) of this section. Part (D) is poorly worded, but the SEC has provided helpful interpretive guidance as explained later in this chapter.

(ii) If unamortized costs capitalized within a cost center, less related deferred income taxes, exceed the cost center ceiling, the excess shall be charged to expense and separately disclosed during the period in which the excess occurs. Amounts thus required to be written off shall not be reinstated for any subsequent increase in the cost center ceiling."

THE FULL COST CEILING AND FAS 121

For companies following the full cost accounting method in Reg. S-X Rule 4-10, both the ceiling test and the FAS 121 impairment test apply in theory, but the FASB and SEC staff have informally indicated that the ceiling test is to be used for proved oil and gas properties in lieu of FAS 121 as explained in Chapter Eighteen. The ceiling test is an SEC rule that is not eliminated by the issuance of a conflicting accounting standard by the FASB. However, the ceiling test is generally more stringent and conservative than the FAS 121 impairment calculation, since the ceiling is based on *discounted* projected future cash flow, whereas FAS 121 does not recognize impairment unless capitalized costs exceed *undiscounted* expected future cash flow. An exception to this general rule may occur when current oil and gas prices for the ceiling test significantly exceed expected future prices used for FAS 121 impairment. Chapter Eighteen addresses these issues more fully.

PART (c)(4)(i)(A): PRESENT VALUE OF FUTURE NET REVENUES

The present value of future net revenues is essentially the discounted present value of future net cash flow from proved reserves. Future net cash flow is based on oil and gas prices and production cost rates as of the balance sheet date applied to the projected production of the company's proved reserves. Costs are the estimated future development, production, and DR&A costs. The calculation requires scheduling production, revenues, and costs by year to apply the ten percent annual discount rate.

The discounted cash flow is computed under the following guidelines:

1. Estimated future *gross* revenues (i.e., what petroleum accountants would simply call future revenues) are determined by multiplying

expected future net production for each year by the applicable sales prices in effect at the end of the current fiscal quarter, with consideration of price changes only to the extent provided by contractual arrangements. Average prices for the past year and expected prices may not be used. Favorable price changes subsequent to the balance sheet date and before release of the financials may be considered to avoid a write-down, but special disclosure is required, as explained later in this chapter.

2. Estimated future expenditures to be incurred in developing and producing the proved reserves each year are deducted from gross revenues. Estimates of future expenditures are to be based on cost levels and cost rates in effect at the end of the current year.
3. A fixed discount of ten percent per annum is used to compute the present value of the *net revenues* (gross revenues less development and lifting costs) to arrive at the net present value of proved reserves.

Conceptually, and in reality, the present value is a sum of present values computed (using petroleum engineering software) on a well-by-well, property-by-property, or field-by-field basis because end-of-year prices and operating cost rates vary widely from one property or field to another as a result of the difference in quality of reserves, the existence of contractual sales prices, and numerous other factors.

To illustrate the computation of discounted present value, assume that KT Oil Company owns a single proved field in a cost center and owns estimated proved reserves of 2,400,000 barrels on December 31, 2000. The price on that date is $17.50 per barrel. The schedule of expected production of those proved reserves is as follows:

	Barrels
2001	1,000,000
2002	700,000
2003	400,000
2004	200,000
2005	100,000
Total	2,400,000

Severance taxes are five percent of revenue. Other production costs are currently $1,500,000 per year. It is anticipated that additional development costs of $7,500,000 will be incurred in 2001 to develop the present proved reserves.

Based on the data given above, the net cash flow and the discounted net cash flow from production of proved reserves are shown in the following table:

Year	Gross Revenue	Lifting and Devel. Costs	Net Cash Flow	Discount Factor[62]	Discounted Cash Flow
2001	$17,500,000	$9,875,000	$ 7,625,000	.9535	$ 7,270,438
2002	12,250,000	2,112,500	10,137,500	.8668	8,787,185
2003	7,000,000	1,850,000	5,150,000	.7880	4,058,200
2004	3,500,000	1,675,000	1,825,000	.7164	1,307,430
2005	1,750,000	1,587,000	163,000	.6512	106,146
	Total		$24,900,500		$21,529,399

In computing the cost ceiling, the value to be assigned to the proved reserves in the above example is $21,529,399.

PART (c)(4)(i)(B): COST OF PROPERTIES NOT BEING AMORTIZED

The costs of both unevaluated properties and unusually significant development projects being withheld from the amortization calculation are generally to be included in the ceiling at the current carrying cost (i.e., at cost less any impaired costs used in the amortization base). Due to the nature of such costs and the impairment requirement, consideration of the fair value of such assets was apparently not deemed necessary.

PART (c)(4)(i)(C): LOWER OF COST OR FAIR VALUE OF UNPROVED PROPERTIES BEING AMORTIZED

The *lower of cost or estimated fair value of unproved properties included in the costs being amortized* is, as a rule, zero if the company's policy is to exclude from amortization all costs of unevaluated unproved property. When that exclusion option is adopted, the costs being amortized are the worthless impaired costs and the worthless costs of

[62]The discount factor is the present value of one discounted at ten percent per annum. This calculation assumes that all cash receipts and expenditures occur at the mid-point of the year discounted to a present value as of December 31, 2000. Thus, the 2001 discount factor is calculated as 1/[(1+10%)^0.5 years], and the 2002 discount factor is calculated as 1/[(1+10%)^1.5 years].

"evaluated unproved property" (i.e., property evaluated as having no proved reserves and, hence, also worthless under normal circumstances). If unevaluated property costs are not being excluded from amortization, then this third component of the ceiling could have some value.

The unproved properties included in the amortization base of the cost center are valued at the lower of cost or market. There is no indication in Reg. S-X Rule 4-10 whether the lower of cost or market for all unproved properties included in the amortization base is to be used or whether the lower of cost or market for each individual property is to be considered. Given the nature of full cost, it would be more practical (and perhaps more appropriate) to use the lower of total cost or total market.

PART (c)(4)(i)(D): INCOME TAX EFFECTS

This requirement is poorly worded, and a literal interpretation is not used in industry nor reflected in SAB Topic 12D on computing the income tax effects.

Reg. S-X Rule 4-10(c)(4)(i)(A), as amended by Financial Reporting Release 40A issued in September 1992, refers to *future net revenues* from proved reserves. Traditionally, the term *future net revenues* referred to net cash flow (not revenues) *before* reduction for income taxes, but traditionally the ceiling reflected cash flow *after* reduction for income taxes. The amended portion (c)(4)(i)(D) does not refer to income tax effects for the future net revenues in (c)(4)(i)(A) as it did before the 1992 amendments. An SEC representative informally clarified in late 1992 that the FRR 40A amendments were not intended to eliminate the income tax effects relating to future net revenues.

Subsection (c)(4)(i)(D) also refers to *book basis* when the term is intended to refer to the future net revenues (or alternatively, the present value of such future net revenues) referred to in section (c)(4)(i)(A) and to the ceiling values referred to in (c)(4)(i)(B) and (C), as indicated in SAB Topic 12D. The ceiling value for proved properties may be substantially different from book value, and hence the related income taxes may be substantially different from recorded deferred taxes that reflect the difference between book and tax basis.

However, the rule's language has yet to be corrected. Based on SAB Topic 12D and informal commentary from SEC staff, companies treat the amended (c)(4)(i)(D) as if it were corrected to read "income tax effects related to differences between (1) the future net revenues and values referred to in Reg. S-X Rule 4-10 (c)(4)(i)(A), (B), and (C) and (2) the tax bases of the related assets."

The calculation of income tax effects is illustrated later in this chapter.

THE COST BASIS AS A NET NET BOOK VALUE

The ceiling is compared to capitalized costs less accumulated amortization (i.e., net book value) and less related deferred income taxes (referred to in this discussion as *net net book value*). Related deferred income taxes refer to the portion of recorded deferred taxes arising from the difference between the book value and tax basis of the oil and gas properties at the applicable balance sheet date.

For example, assume that KT Oil Company has the following components of net net book value at December 31, 2000:

Proved property costs		$32,000,000
Unproved costs in amortization base ($0 fair value)		4,700,000
Amortization base		36,700,000
Costs excluded from amortization base		10,000,000
Less accumulated DD&A[63]		(15,000,000)
Net book value		31,700,000
Related deferred income taxes:		
Net book value	$31,700,000	
Less tax basis of proved property	(5,000,000)	
Less tax basis of unproved property included in amortization base	0	
Less tax basis of excluded costs	(8,000,000)	
Equals book-tax difference	18,700,000	
Times 40% effective tax rate	x 40%	
Equals related deferred income taxes	$ 7,480,000	(7,480,000)
Net net book value		$24,220,000

[63] Under accounting standards in effect in early 2000, the accumulated DD&A usually includes the accumulated provisions for DR&A. Proposed ARO standards (Chapter Twenty) would exclude DR&A (aka ARO) for the FAS 121 impairment tests (Chapter Eighteen). Conceivably, when and if the ARO standards take effect, the SEC might have the full cost ceiling test amended or interpreted to similarly exclude ARO amounts from the test.

ILLUSTRATION OF INCOME TAX EFFECTS CALCULATION

Theoretically, the income tax effect relating to future net revenue from proved property should be calculated future year by future year using the future cash flow schedule for (c)(4)(i)(A). These future taxes, calculated year by year, are then discounted to a present value.

The income tax effects relating to the values in (c)(4)(i)(B) and (C) are the taxes on the difference (often minimal) between the values in (B) and (C) and the properties' tax bases as of the effective date of the ceiling test, as if the properties relating to (B) and (C) were sold on that date for the values used in (B) and (C).

The calculated income tax effects are then added together to determine the ceiling component for (c)(4)(i)(D). These calculations are collectively called the year-by-year approach because the largest component reflects income taxes on future net revenues calculated future year by future year and discounted to a present value.

The *year-by-year* approach to calculating the income tax effect has an *acceptable* alternative allowed under SAB Topic 12D, which is called the *short-cut* approach. The short-cut approach is similar in many ways to assuming that all the properties, including the proved properties, are sold as of the balance sheet date at the values in (c)(4)(i)(A), (B), and (C). The short-cut approach calculates related income taxes as the income taxes paid on the gain from the *sale*. However, the short-cut approach allows recognition of statutory depletion (percentage depletion) not available in selling the properties, only in producing the property. So it is truly a short-cut to the year-by-year calculation and not truly an approach assuming the immediate sale of the proved properties.

In both approaches, the income tax calculations consider current tax bases of the oil and gas assets, as well as any related net operating loss carryforwards and tax credits.

Assume the facts above for KT Oil Company and assume the following:

- The $7,500,000 of 2001 development costs includes $5,100,000 immediately deductible as intangible development costs and $2,400,000 of equipment costs depreciable for tax purposes on a unit-of-production basis, as reflected in the following schedule.
- The $5,000,000 tax basis of proved property is deductible, as reflected in the schedule below.

- The KT Oil Company will have additional percentage depletion deductions, as reflected in the schedule below.
- The combined federal and state income tax rate is 40 percent.
- The taxes are paid on average midway through the year whereby the same discount factors in the prior schedule are used for the schedule below.
- The KT Oil Company has no income tax credits or net operating loss carryforwards.

Then the income tax effects relating to future net revenue are calculated in the schedule below:

(in thousands)	2001	2002	2003	2004	2005	Total
Net cash flow	$ 7,625	$ 10,138	$ 5,150	$ 1,825	$ 163	$ 24,901
Add back '01 equip. costs	2,400	-	-	-	-	2,400
Depreciate '01 equipment	(1,000)	(700)	(400)	(200)	(100)	(2,400)
Deduct 12/31/00 tax bases	(1,825)	(2,138)	(550)	(425)	(62)	(5,000)
Deduct addt'l. % depletion	(200)	(300)	(200)	(200)	(1)	(901)
Taxable income	$ 7,000	$ 7,000	$ 4,000	$ 1,000	$ -	$ 19,000
Income tax at 40%	$2,800	$2,800	$1,600	$400	$ -	$7,600
x discount factor	0.9535	0.8668	0.7880	0.7164	0.6512	n/a
Income tax present value	$ 2,670	$ 2,427	$ 1,261	$ 287	$ -	$ 6,645

Under the year-by-year approach, the income tax effect relating to the future net revenues is $6,645,000. The income tax effects relating to the values in (c)(4)(i)(B) and (C) are much smaller, computed as follows:

	(c)(4)(i)(B)	(c)(4)(i)(C)
Value	$10,000,000	$0
Less tax basis	(8,000,000)	(0)
Difference	$ 2,000,000	$0
Tax effect at 40%	$ 800,000	$0

For costs excluded from amortization, the corresponding tax basis is typically smaller because some of those costs are generally tax deductions when incurred, such as intangible drilling and development costs and delay rentals.

For the example above, the combined income tax effect under the year-by-year approach is $6,645,000 plus $800,000, equaling $7,445,000.

Under the alternative short-cut approach allowed under SAB Topic 12D, the income tax effect is calculated as follows, assuming that the present value of the additional percentage depletion is $800,000:

Present value of future net revenues		$21,529,399
(c)(4)(i)(B) value of excluded costs		10,000,000
(c)(4)(i)(C) value of unproved property being amortized		0
Ceiling value before income tax effects		31,529,399
Less tax bases and other deductions:		
Tax basis of proved property	$ 5,000,000	
Tax basis of excluded costs	8,000,000	
Tax basis of unproved property included in amortization base	0	
Present value of statutory depletion	800,000	
Net operating loss carryforwards	0	
	$13,800,000	(13,800,000)
Difference between value and tax basis		$17,729,399
Income tax effect at 40% combined tax rate using the short-cut approach		$ 7,091,760

In this example, the $7,091,760 income tax effect under the short-cut approach is five percent less than the $7,445,000 calculated under the year-by-year approach. Generally, the short-cut approach calculates tax effects to be slightly less than those under the year-by-year approach because the short-cut assumes that the proved property tax basis is immediately deductible.

ILLUSTRATIVE CEILING TEST

For the example above, the ceiling tests, using both alternative income tax calculation approaches, would be as follows:

	Year-by-year	Short-cut
Ceiling, pre-tax	$31,529,399	$31,529,399
Less income tax effect	(7,445,000)	(7,091,760)
Ceiling	24,084,399	24,437,639
Less net net book value	(24,220,000)	(24,220,000)
Excess book value [write-down]	$ (135,601)	
Excess ceiling [no write-down]		$ 217,639

Since SAB Topic 12D states that the short-cut approach is *acceptable*, companies using it may not need to record a write-down for the example above. However, if a write-down is recorded, it needs to adjust both the assets and the related deferred income taxes. Assuming a net write-down of $600,000 and a 40 percent income tax rate, the journal entry to record the write-down would be similar to the following:

761	Provision for Impairment of Oil and Gas Assets	1,000,000	
420	Deferred Income Taxes [a liability a/c]	400,000	
	237 Accumulated Impairment of Oil and Gas Property Cost Centers		1,000,000
	945 Deferred Federal Income Tax Provision*		400,000

To record impairment of carrying value of oil and gas properties in [country cost center] to cost ceiling.

*For simplicity, Account 946 for state taxes is ignored here

CEILING EXEMPTION FOR PURCHASED PROVED PROPERTY

Companies may purchase proved property at a cost that exceeds the related increase in the full cost ceiling. The property's cost might reflect the value of expected price increases or probable reserves not reflected in the ceiling. It seems unfair to require a write-down due to purchase of a property at its fair value. Hence, SEC Accounting Series Release No. 258 provides that a registrant may request an exemption from the ceiling test when the write-down is attributable to purchased proved property and the registrant believes the fair value of its properties exceeds their net book value.

SAB Topic 12D, Question 3, explains how the ASR 258 ceiling exemption can be obtained. The registrant is to request from the SEC staff a temporary waiver from the ceiling test as to the purchased property whereby the cost and ceiling value of the purchased property is excluded from the ceiling computation. The registrant requesting a waiver should be prepared to demonstrate that the additional value exists beyond a reasonable doubt. The purchased property's fair value as of the ceiling test date should be, beyond a reasonable doubt, at least sufficient to eliminate the need for the write-down, as illustrated by the following two examples:

[in thousands]	Ceiling	Net Net Book Value	Write-down
Example #1:			
Ceiling test with exemption	$19,000	$20,000	$1,000
+ Purchased property	8,000	10,000	2,000
= Ceiling test without exemption	$27,000	$30,000	$3,000
Example #2:			
Ceiling test with exemption	$20,500	$20,000	$ (500)
+ Purchased property	8,000	10,000	2,000
= Ceiling test without exemption	$28,500	$30,000	$1,500

In the first example, the registrant should demonstrate with reasonable certainty that the fair value of purchased property at the time of the ceiling test is at least equal to the $10,000,000 purchase price, so that the ceiling write-down is limited to the $1,000,000 write-down for other properties.

In the second example, the registrant should demonstrate with reasonable certainty that the fair value of the purchased property at the time of the ceiling test is at least $9,500,000. If that value were used in the ceiling, the total ceiling would equal the $30,000,000 total net net book value, avoiding a write-down. In this case, the property's reasonably certain fair value can be less than its book value and still avoid a write-down.

SUBSEQUENT EVENTS' EFFECTS ON CEILING TEST

SAB Topic 12D, Question 3, also allows a write-down to be avoided if the ceiling test considers one of two types of events occurring after the ceiling test date (the balance sheet date) but before the auditor's report on the affected financial statements:

1. Additional reserves are proved up on properties owned at year end, or
2. Price increases become known that were unknown as of the balance sheet date.

If the ceiling were recomputed giving effect to such event(s) [both cost and ceiling adjustments] and no write-down were so calculated, then no write-down need be recorded. If a smaller write-down were calculated, it should be recorded.

By analogy, an interim ceiling write-down could be avoided if the subsequent events occurred prior to issuance of the unaudited quarterly financials.

The registrant's financial statements should disclose that "capitalized costs exceeded the limitation at [the balance sheet date] and should explain why the excess was not charged against earnings."

The registrant's supplemental disclosures of proved reserves (see Chapter Twenty-Eight) and of the related standardized measure (see Chapter Twenty-Nine) should not reflect the subsequent event(s). However, the effects could be disclosed separately, with appropriate explanation.

Property acquisitions after the balance sheet date may not be considered.

Price declines after the balance sheet date need not be considered in the ceiling test, but substantial declines may require disclosure of a material subsequent event.

MINERAL CONVEYANCES AND PROMOTIONAL ACTIVITIES

Full cost companies are subject to many of the same rules applicable to successful efforts companies in accounting for mineral conveyances and promotional activities. In addition, a number of additional guidelines must be observed by those using full cost. These rules are discussed in Chapters Twenty-One through Twenty-Four. Figure 24-2 provides a decision chart on general accounting for property sales under full cost accounting.

Chapter Twenty

ASSET RETIREMENT OBLIGATIONS

An *asset retirement obligation* ("ARO") is an unavoidable cost associated with the retirement of a long-lived asset that arises as a result of either the acquisition or the normal operation of the asset. In the oil and gas industry, these obligations include the future dismantlement and removal of production equipment and facilities and the restoration and reclamation of a field's surface lands to an ecological condition similar to that existing before oil and gas extraction began. These costs are usually required by federal, state, and foreign regulations or under contractual obligations and are typically paid when oil and gas reserves are depleted, i.e., when it is no longer economically feasible to continue production.

This chapter is divided into three sections:

- Regulatory and Operational Environment,
- Current Accounting, and
- Exposure Draft on Accounting for Asset Retirement Obligations.

REGULATORY AND OPERATIONAL ENVIRONMENT

Regulations governing lease and well abandonment are dependent on the jurisdiction in which the related property resides. Regardless of the jurisdiction, producers are typically required to obtain permits from local regulatory authorities before dismantlement, restoration, and reclamation activities can begin. Regulators usually require well logs or test flow data to verify that the well to be abandoned no longer has the capacity to produce economic quantities of oil and gas. Regulators also require detailed work plans and assurances that the plugging and abandonment activities will not jeopordize the safety or economic operation of nearby wells or pose any hazard to the surrounding environment.

In some of the more mature producing areas of the world, such as the Gulf of Mexico outer continental shelf, viable abandonment techniques have been established and accepted by the U.S. Minerals Management Service, and obtaining the necessary abandonment permit is relatively easy. For example, toppling is now a technique used in offshore abandonment of oil and gas production facilities. Toppling involves the removal of the top section of the platform (i.e., decks, jackets, and facilities) above a certain required clearance below the water surface using either explosive or non-explosive cutting techniques. In most cases, clearance of at least 50-75 meters below the surface is required. The tops are then towed to shore where they are scrapped or, alternatively, placed on the adjacent seabed or towed to designated reef sites and sunk. In many instances, regulations allow the remaining subsurface structures to be left in place. Environmental impact studies have revealed that leaving the sub-surface structures in place is actually beneficial to the ecology, a factor which has benefited producers by significantly reducing the costs associated with removing the entire structure. In other geographical areas, regulations may be much more stringent requiring that the ocean floor be returned to its original state. This usually requires removal of the entire platform, including the casing, wellhead equipment, and pilings, to a specified depth below the ocean floor. Any associated flow lines can generally be flushed, cleaned of all hydrocarbon-bearing parts, plugged, and left in place. In most cases, the salvage values of such lines do not justify the cost required to bring them to the surface.

Obtaining permits in other less developed areas of the world may be much more onerous. Due to the lack of production history and a continuing debate among local regulatory and scientific communities as to what techniques qualify as environmentally friendly, producers in many frontier areas are required to perform detailed scientific and environmental impact studies and present alternative abandonment plans before a permit is granted. In evaluating the various plan options, regulators commonly give consideration to the following factors:

- Technical and engineering aspects of the plan;
- Potential reductions in the consumption of natural resources as a result of re-use and recycling contemplated in the plan;
- Potential impact of the plan on the environment, including exposure of biological habitation, emissions to the atmosphere, groundwater, soil, or surface fresh water;
- Potential interference with other legitimate uses of the physical environment, such as shipping lanes and commercial fishing areas;
- Safety considerations;
- Management measures that will be implemented to prevent or mitigate adverse consequences of the plan;
- The party responsible for the future environmental monitoring activities associated with the plan;

- The party liable for meeting claims for any damages caused by the planned abandonment activities; and
- Notification of appropriate authorities as to the modification or movement of any installations or facilities such that nautical charts and other physical environmental aids are appropriately modified.

Because most exploration and production companies operate in numerous areas around the world, it is not uncommon for oil and gas companies to maintain a compliance department whose responsibilities include monitoring the evolution of the regulatory environments in various jurisdictions.

Much like the oil and gas reserve estimation process, estimating future abandonment and reclamation costs is not an exact science. Those responsible for estimating these costs must constantly revise their assumptions to reflect changes in reserve life, cost structures, technological advancements, and changes in the regulatory environment. In addition to evaluating the abandonment options permitted under local regulations, there remain numerous other factors and uncertainties that must be considered in estimating the cost to abandon oil and gas production facilities. For example, future contract labor rates and heavy equipment rental costs, in particular, are very difficult to predict given that many contiguous production areas may reach the end of their operational life at the same time, thereby putting excess demand on the local resources available to provide abandonment services. Expected levels of inflation and future market values for scrapped parts are also factors that are very difficult to predict with any degree of certainty.

CURRENT ACCOUNTING

Accounting for asset retirement obligations in the oil and gas industry historically posed little difficulty in most routine onshore development and production activities. Most operators merely assumed that salvage values would be equal to the cost of dismantling the facilities and carrying out necessary clean-up and reclamation activities; thus net dismantlement costs were typically ignored. However, as a result of the expansion of oil and gas exploration and production activities into more remote and environmentally sensitive areas and the continuing evolution of regulations by various federal, state, and local governments, the costs to abandon and remediate oil and gas properties may be extremely large, in some cases exceeding the cost incurred to originally construct and install related facilities.

Current authoritative literature requires that these asset retirement obligations be recognized as the related oil and gas reserves are produced rather than when the asset retirements occur. For companies following the successful efforts method of accounting, Oi5.128 requires that "[e]stimated dismantlement, restoration, and abandonment ["DR&A"] costs and estimated residual salvage values shall be taken into account in determining amortization and depreciation rates."

Similarly, for companies following the full cost method of accounting, SEC Regulation S-X Rule 4-10(c)(3)(i) requires that "[c]osts to be amortized shall include…estimated dismantlement and abandonment costs, net of estimated salvage values."

Although the current authoritative literature requires that future DR&A costs be considered in the depreciation or amortization computation, until recently no specific guidance has been given as to how these future costs are to be measured or recorded. For example:

- Should a liability for future DR&A costs be recorded at the time of acquisition or development, or should the liability be accrued during the productive life of the related reserves?
- If a liability is recorded at the time of acquisition or development, should the amount be recorded as part of the facility's costs? Should the liability be recorded net of salvage value?
- What is the proper measure of the future costs (costs based on price levels at the time of development or based on expected cash outlays at the time of removal and restoration)? Should the future costs be discounted to present value?

In 1993, the FASB's Emerging Issues Task Force examined two of these questions in the context of future environmental liabilities. In EITF Issue No. 93-5, *Accounting for Environmental Remediation Liabilities,* the EITF concluded that discounting future costs is acceptable when the aggregate amount and timing of the future cash flows are readily determinable. The EITF also concluded that an environmental liability should be evaluated independently of any third party recoveries (i.e., expected recoveries from salvage). Any reduction in a liability for potential recoveries from third parties is appropriate only in instances where the recovery is at least probable.

In 1993 the SEC issued Staff Accounting Bulletin 92, *Accounting and Disclosures Relating to Loss Contingencies.* SAB 92 clarified the SEC's position on the recognition and measurement of future environmental liabilities. Environmental clean-up costs, which would include any remedial obligations that may apply to oil and gas exploration and production activities, are specifically addressed. SAB 92 states that companies should not delay recognition of a liability until only a single estimate can be determined, and although a range of costs associated with a loss contingency may be broad, the minimum cost is unlikely to be zero. Citing EITF Issue 93-5, SAB 92 also states that the offsetting of potential third party recoveries against liabilities is not appropriate and that such obligations should be recorded gross on the balance sheet as a liability. SAB 92 also cites EITF 93-5 as to when it is appropriate to record the liability at a discounted present value.

In 1996, the Accounting Standards Executive Committee (AcSEC) of the American Institute of CPAs (AICPA) issued Statement of Position No. 96-1, *Environmental Remediation Liabilities*, requiring environmental liabilities to be accrued whenever the criteria in FAS 5 are met. SOP 96-1 took a position similar to the SEC's in SAB 92, stating that liability recognition should not be precluded even though certain components of the overall liability may not be reasonably estimable. As long as a range of estimation is possible, the reasonably estimable criterion is deemed to have been met, and a liability should be recorded.

EITF Issue 93-5, SAB 92, and SOP 96-1 have not resulted in significant changes in accounting of DR&A by oil and gas companies.

EXAMPLES OF METHODS

Based on the evolution of GAAP in this area, a strong theoretical case can be made for considering the estimated future removal and restoration costs of oil and gas properties as part of the facility's capitalized costs and as a liability at the time of acquisition or development. This theory has been adopted by the FASB in its exposure draft on asset retirement obligations discussed later in this chapter.

Following are descriptions of methods currently being used to account for these costs. Regardless of the method used, the total estimated future liability should be disclosed in a footnote to the financial statements if the amount is material (per SAB Topic 5Y, Question 7, as added by SAB 92). For illustrative purposes, assume that an offshore platform is built in 2000 at a cost of $100,000,000. Proved reserves (assume all are developed) are estimated to be 30,000,000 barrels of oil at the date of development. Assume 500,000 barrels are produced in the year 2000. At the end of 2000, the estimated asset retirement obligation, net of equipment salvage value, is $24,000,000.

Adjusted Amortization Method

In practice, the application of Oi5.128 has resulted in the use of a *negative salvage value method* whereby the accrued DR&A costs, net of estimated salvage values, are charged to amortization expense and credited to the accumulated amortization account. In the example above, the adjustment for the estimated retirement obligation under this method would be $400,000, calculated as follows:

$$\frac{\$24{,}000{,}000}{30{,}000{,}000 \text{ bbls}} \times 500{,}000 \text{ bbls} = \$400{,}000$$

This amount would be recorded as follows:

735 Amortization for Accrual of Future DR&A Costs	400,000	
235 Accumulated Amortization for Accrual of Future DR&A Costs		400,000

To record amortization for future dismantlement, restoration, and abandonment costs.

Notice that the negative salvage value method does not accrue a liability, but instead reduces an asset. The wording in Oi5.128 does not specifically preclude crediting a liability account, but in the *1999 PricewaterhouseCoopers Survey* a majority of the respondents reported that they were crediting accumulated amortization as opposed to crediting a liability account. Doing so would result in an individual cost center having negative book value toward the end of its productive life. Some respondents to the *1999 PricewaterhouseCoopers Survey* indicated that they reclassify any excess of accumulated amortization over capitalized costs in an individual cost center to a liability account.

The accrual of DR&A costs over the life of a field or property makes it convenient to adjust for changes in cost estimates. At the end of each period, a new estimate of costs should be made, and the amount not previously accrued should be amortized over the remaining reserves. For example, assume the same facts as in the preceding example, and assume that 1,000,000 barrels are produced in 2001, that estimated remaining reserves at the end of 2001 are 28,500,000 barrels, and that a new estimate of DR&A costs at the end of 2001 is $27,000,000. The accrual adjustment at the end of 2001 will be $901,695:

$$\frac{\$27{,}000{,}000 - \$400{,}000}{28{,}500{,}000 \text{ bbls} + 1{,}000{,}000 \text{ bbls}} \times 1{,}000{,}000 \text{ bbls} = \$901{,}695$$

Under this approach, the DR&A costs are charged to expense as the reserves to which they apply are produced. However, if the estimated costs change, as they are almost sure to do, the cost per unit will change under this method. The effect on per-unit cost may be especially significant if costs are increasing while at the same time the number of units over which the increased costs must be spread is decreasing. Those who support this approach argue that increased oil and gas costs due to inflation over many years should be accompanied by increased oil and gas prices so that the distortion in income is reduced. Some of the distortion resulting from simultaneous increases in costs and decreases in reserves would be eliminated by basing the cost estimates on future cost levels rather than on current cost levels. When the actual costs are incurred, the expenditures will be charged against the accumulated amortization account, whereas any amount not previously accrued will be charged to expense.

Another approach to making adjustments for changes in cost estimates is to make a *catch-up* adjustment each time the cost estimates are revised. Under this approach, a determination is made as to the amount that would have been recognized had the revised provision for DR&A costs been assumed when the accumulation of such costs first began.

This procedure can be illustrated using the data provided in the preceding example. At the end of 2001, estimated remaining reserves are 28,500,000 barrels. During 2000 and 2001, 1,500,000 barrels are produced, so that the original reserves are 30,000,000 barrels. The revised DR&A costs as of the end of 2001 are $27,000,000. Based on these figures, the total provision through 2001 should be $1,350,000 (i.e., $27,000,000 times 1,500,000 bbls, divided by 30,000,000 bbls). Since $400,000 was recorded in 2000, the provision for 2001 is $950,000.

Liability Accrual Method

Another method used in practice results in the recognition of a liability as opposed to increasing accumulated amortization. Using the above example, amounts for the year 2000 would be recorded as follows:

735 Amortization for Accrual of Future DR&A Costs	400,000	
410 Accrual for Future Site Restoration [net DR&A] Costs		400,000
To record estimated expense for future DR&A costs.		

SALVAGE VALUE

As noted in Chapter Seventeen, the amortization base is reduced by the estimated future salvage value of equipment. Accountants should be careful that the reduction for salvage value is not double-counted as a reduction in the amortization base and a reduction in the estimated future DR&A costs being added to the amortization base.

EXPOSURE DRAFT ON ASSET RETIREMENT OBLIGATIONS

Because of the diversity in practice in accounting for dismantlement and reclamation costs in various industries, the FASB has issued an exposure draft for a proposed statement of financial accounting standards entitled *Accounting for Obligations Associated with the Retirement of Long-Lived Assets* to be effective for fiscal years beginning after June 15, 2001. If adopted in its proposed form, the standard will dramatically change the petroleum industry's practices in accounting for future ARO costs by requiring these costs be recognized as a liability when incurred (i.e., when the asset is acquired or constructed, when new laws are enacted, or when contractual provisions change). The exposure draft specifically cites the construction and placement of an oil and gas production facility, not the operation of the facility, as the event that gives rise to an obligation requiring liability recognition. Upon initial recognition of a liability, an entity will also be required to capitalize that cost by recognizing a corresponding increase in the carrying amount of the related oil and gas asset. The amount capitalized should be allocated to expense using a systematic and rational method over the life of the asset.

The exposure draft proposes that the initial liability be recorded at fair value (as opposed to the present value of expected costs to be incurred). Since these obligations will be settled in the future, an active market for settling the obligations probably will not exist, and a present value technique will typically be used as the most reliable measure of fair value. The exposure draft proposes that estimated future cash flows be discounted using a weighted average, credit-adjusted, risk-free interest rate and, consistent with the fair value concept, include a profit margin. Changes due merely to the passage of time would be measured as an increase in the liability and as interest expense. The interest would not be subject to capitalization.

Subsequent changes in fair value due to changes in the timing or amount of cash flows will be recorded as an adjustment to the carrying value of the liability and the related capitalized cost of the asset discounted using the interest rate in effect when the liability was initially measured.

The transitional requirements of the exposure draft call for the estimated future ARO to be recorded as if the provisions of the standard had been in effect when the ARO was initially incurred using information, assumptions, and interest rates in effect as of the date of adoption. Therefore, a liability will be recorded for the existing obligation adjusted for cumulative interest incurred up to the date of adoption. A corresponding asset will also be recorded along with the accumulated depreciation that would have been incurred up to the period of adoption. Any difference between the amounts recorded on the statement of financial position prior to the adoption of this standard and amounts that are recognized after adoption will be recorded as a cumulative effect adjustment in the income statement.

APPLICATION ISSUES

The ARO exposure draft will be subject to due process and input from various constituencies before a final standard is issued. Following are potential implementation issues for the oil and gas industry.

AMORTIZATION OF THE CAPITALIZED ARO COST

The ARO exposure draft calls for allocation of the asset retirement cost using a systematic and rational method over periods no longer than that for which the related asset is expected to provide benefits. The appendix to the exposure draft provides an example of an entity that completes the construction of, and places into service, an offshore oil platform. In this example, the capitalized ARO cost is amortized on a straight-line basis over the expected useful life of the asset. The straight-line treatment afforded in this example appears contradictory to the guidance provided for both full cost and successful efforts companies. SFAS 19 and Regulation S-X Rule 4-10 both require capitalized costs to be amortized on a unit-of-production basis.

In the Exposure Draft, the FASB indicated that the fair value of the ARO should be reflected as part of the historical cost of the asset. Furthermore, the FASB reasoned that the capitalized ARO cost does not represent a separate asset since there is no separate future economic benefit resulting from the ARO. For these reasons, a compelling argument could be made that the capitalized ARO cost should be amortized in a manner that is consistent with the other costs necessary to prepare the asset for its intended use. For companies following the full-cost method of accounting, the capitalized ARO cost would be included in the appropriate cost center and amortized over the remaining total proved reserves. For companies following the successful efforts method of accounting, the capitalized ARO cost would be included as part of the cost of the related wells, equipment, and facilities to be amortized over the remaining proved *developed* reserves. Because ARO costs are directly linked to development activity, it would not be appropriate to treat such costs as acquisition costs to be depleted over *total* proved reserves. Undeveloped reserves, by definition, will require new wells or major expenditures before they can be classified as proved *developed* reserves. Along with the construction of these new wells and the associated transfer of reserves from undeveloped to developed comes an additional obligation to retire these assets in the future.

IMPAIRMENT

The ARO exposure draft calls for the recognition of an asset retirement obligation by increasing the carrying amount of the related long-lived asset by the same amount as the corresponding liability. Furthermore, the proposed standard requires that a long-lived asset, including the capitalized ARO value, be subject to an impairment test pursuant to the provisions of FAS 121. However, the exposure draft acknowledges the fact that, to the extent a liability for the closure or removal obligation has already been recorded, considering those same cash flows in assessing the need for impairment under FAS 121 would inappropriately double count the impact of the obligation. As a result, ARO cash outflows should be excluded from the FAS 121 expected future cash flows used to test the asset for recoverability and from the FAS 121 discounted cash flows determining fair value of the asset.

For example, assume an oil and gas property's net book value is $50 million including $10 million of capitalized ARO cost. Assume the property's expected future cash flow is only $38 million, net of expected ARO costs of $20 million. The exposure draft has FAS 121 impairment based on the net book value of $50 million being compared with $58 million of expected future cash flow (disregarding the ARO cash outflow). Under the proposed rules, there is no impairment for the example given. The exposure draft does not call for $40 million of net assets (i.e., net of the $10 million ARO liability) to be compared to $38 million of expected future net cash flow (i.e., net of the $20 million ARO liability).

PERIOD COSTS

Due to the lack of an active market for settling a future ARO, most oil and gas companies will employ a present value technique in determining fair value. The exposure draft requires changes in the liability due to the passage of time be recognized as interest expense. This requirement will significantly change current practice, which ignores the time value component and simply accounts for all changes in the future obligation as an adjustment to DD&A expense. The new standard will effectively shift the time value component of the future ARO cost currently accounted for as an operating expense into non-operating interest expense.

RECOGNITION OF AN ARO LIABILITY

Various contractual arrangements unique to the oil and gas industry raise a logical question as to whether the criteria for recognition of a liability under the exposure draft have been met. For example, a reversionary interest is a contractual arrangement in which an entity returns its economic interest in an oil and gas property to the former owner after a predetermined amount of production or income has been produced. If an oil and gas company has a 60% working interest in a field but expects to lose one-fourth of such interest due to a reversion upon payout, the company would expect to bear only 45% of the future ARO costs. Depending on how specific contracts are written, other arrangements such as net profits interests and rights to volume production payments may give rise to assets without corresponding asset retirement obligations.

SALVAGE VALUE

The exposure draft states that in measuring the fair value of an asset retirement obligation using an estimated fair value technique, entities should consider the amounts, both outflows and inflows, that a third party would consider in determining the price of settling the obligation. Given the current authoritative GAAP in this area, the practice of offsetting expected salvage values on the balance sheet against future ARO would only be appropriate in instances where a right of offset exists. The wording of Oi5.128 is retained in the new standard with respect to the income statement treatment. Specifically, estimated residual salvage values should still be considered in determining amortization and depreciation rates. Assuming no legal right of offset on the balance sheet exists, the capitalized costs included in the numerator of the DD&A calculation would be reduced by the expected salvage value. An amount equal to the salvage value would remain in the property account at the end of the asset's productive life to be offset when the proceeds from salvage are received.

OTHER CONSIDERATIONS

The initial application of this standard will require entities to recognize an ARO liability and a corresponding increase to long-lived assets. Over time, assuming no changes in estimates, the liability will be increased for time value while the asset will be reduced by amortization. Companies will need to evaluate the impact these financial statement changes will have on current and future contractual arrangements, debt covenants, and key financial ratios.

Chapter Twenty-One

ACCOUNTING FOR CONVEYANCES

A mineral conveyance is the transfer of any type of ownership interest in minerals from one entity to another entity. In the initial mineral lease agreement, the lessor conveys to the lessee a 100 percent working interest in the property, and the lessor retains a royalty interest. The lessee may in turn transfer in another conveyance all or a part of the working interest to a third party. For example, the lessee may sell all of the working interest outright, may sell a fractional share of the working interest, may assign the working interest and retain a nonoperating interest (a sublease), or may *carve-out* and transfer an overriding royalty, a net profits interest, or a production payment to a transferee. Likewise the holder of a royalty interest or other nonoperating interest may convey all or a portion of that interest to another party. In many instances conveyance contracts are quite complex and may burden one of the parties with additional obligations and commitments.

There are many reasons why owners, especially working interest owners, convey interests in mineral properties. These reasons include the desire to share the risks of ownership and the costs of exploration and development with others, to obtain financing, to improve operating efficiency or conservation, and to achieve tax benefits.

GENERAL PRINCIPLES OF ACCOUNTING FOR CONVEYANCES

FAS 19 provided general guidelines for mineral conveyance accounting. Although FAS 25 suspended indefinitely most of FAS 19's rules, it did not suspend the FAS 19 rules relating to conveyances that are in substance borrowings. In Reg. S-X Rule 4-10, the SEC adopted FAS 19's conveyance accounting rules (found in Oi5.133 through Oi5.138) for all publicly held oil and gas producing companies, including (with some modifications) those using the full cost method of accounting.

The basic guidelines of Oi5 and Reg. S-X Rule 4-10 are summarized below:

1. Some conveyances are in substance borrowings repayable in cash or its equivalent and should be accounted for as borrowings (even by privately held companies).
2. Gain or loss should generally not be recognized at the time the following types of conveyances are made:
   A. A transfer of assets used in oil and gas producing activities in exchange for other assets also used in oil and gas producing activities.
   B. A pooling of assets in a joint undertaking intended to find, develop, or produce oil or gas from a particular property or group of properties.
3. Gain should not be recognized (although loss may be[64]) at the time the following types of conveyance are entered into:
   A. Part of an interest is sold, and substantial uncertainty exists about recovery of the cost applicable to the retained interest.
   B. Part of an interest is sold, and the seller has a substantial obligation for future performance, such as an obligation to drill a well or to operate the property without proportional reimbursement for that portion of the drilling or operating costs applicable to the interest sold.
4. Gain or loss should generally be recognized on other types of conveyances by successful efforts companies unless generally accepted accounting principles would prohibit such recognition.
5. With limited exceptions, no gain or loss should be recognized by a full cost company on a mineral conveyance. The major exception is a situation in which the conveyance is so large that to treat the

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[64]FAS 19 only prohibits gain from being recognized. Par. 221 states that "recognition of a loss should not be prohibited," implying that loss recognition at the time of sale is optional. However, if the loss were not recognized at the time of sale of an unproved property, a loss would effectively be recognized when the remaining capitalized cost is subject to impairment analysis (FAS 19, Note 4). For example, if one sells 50 percent of an unproved property costing $10,000 for $2,000, it seems unreasonable not to recognize an impairment loss, i.e., to carry the unsold 50 percent interest at $8,000, when the sale demonstrates a value of only $2,000 and an impairment of $6,000. The amount of loss recognized due to impairment will depend in part on whether the unproved property is assessed for impairment individually or in a group.

> proceeds as a recovery of cost would significantly distort the rate of amortization. This exception is discussed in the latter part of this chapter.

In order to simplify the discussion of complex accounting problems, our discussion of the application of these general rules to specific conveyances will be divided into three sections. In this chapter we shall examine the appropriate handling of conveyances that may be classified as sales and subleases in which the sole consideration is cash or cash equivalent. The next chapter contains a discussion of conveyances in which payments out of oil or gas (production payments) are involved. Finally, conveyances in which the sole consideration is an agreement by the transferee to perform specified exploration or development work (sharing arrangements) are discussed in the third chapter.

The special rules for sales and abandonments under the full cost method adopted by the SEC are discussed at the end of this chapter. The reader is urged to read carefully Oi5.133 through Oi5.138 and Reg. S-X Rule 4-10(c)(6) in studying the accounting rules for conveyance transactions.

SALES AND SUBLEASES OF UNPROVED MINERAL INTERESTS

When mineral properties are sold or exchanged for cash or cash equivalent, several factors must be considered in determining the appropriate treatment for a company using the successful efforts method of accounting.[65] These factors include whether the property is classified as proved or unproved, whether impairment of an unproved property is being recorded on an individual property basis or on a group basis, whether amortization of a proved property is being computed on an individual property basis or on the basis of a geological group, and whether an entire interest or only a partial interest is conveyed. The importance of these factors is apparent in the following specific illustrations.

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[65] Under Reg. S-X Rule 4-10(c)(6), companies using the full cost method will normally report no gain or loss on sales of oil and gas properties or on abandonment of properties.

SALE OF ENTIRE WORKING INTEREST IN UNPROVED PROPERTY

If the entire interest in an unproved property is sold, recognition of gain or loss depends on the method used to record lease impairment. Oi5.138(g) provides that if impairment has been determined on an individual property basis, gain or loss will be recognized to the extent of the difference between the proceeds received and the net carrying value of the property. For example, assume an unproved property with a $100,000 original cost and a $25,000 impairment allowance (recorded on an individual property basis) is sold for $80,000. A gain of $5,000 is recognized on the sale, as shown below:

101	Cash	80,000	
219	Allowance for Impairment . . . of Unproved Properties	25,000	
	211 Unproved Leaseholds		100,000
	620 Gains on Property Sales		5,000
To record sale of lease.			

If, however, the lease is part of a group of leases for which the allowance for impairment has been determined on a group or composite basis, no gain or loss will be recognized because the $80,000 in sales proceeds does not exceed the $100,000 original cost of the lease. Oi5.138(g) states that

> for a property amortized by providing a valuation allowance on a group basis, neither gain nor loss shall be recognized when an unproved property is sold unless the sales price exceeds the original cost of the property, in which case gain shall be recognized in the amount of such excess.

For example, assume a lease impaired on a group basis and originally costing $100,000 is sold for $125,000. The entry to record the sale is shown below:

101	Cash	125,000	
	211 Unproved Leaseholds		100,000
	620 Gains on Property Sales		25,000
To record sale of lease.			

The recognition of gain on the sale of a property that is part of a group appears to be an abrogation of the general rule that no gain or loss should be recognized when a single asset being accounted for as part of a group is disposed of.

Under full cost, the cash proceeds in each of the above cases would generally be treated as a recovery of cost, with no gain or loss recognized. The cost of the property sold may be credited to the cost pool (the unproved mineral interests account), with the difference between the proceeds and the cost being charged or credited to the allowance for amortization of oil and gas asset accounts. This procedure is illustrated in the latter part of this chapter.

SALE OF SHARE OF WORKING INTEREST IN UNPROVED PROPERTY

If only part of an interest in an unproved property is sold (either a divided interest or an undivided interest), under Oi5.138(h), no gain is to be recognized on the transaction unless proceeds from sale of the partial interest exceed the cost of the entire property. A loss on the sale is recognized either directly (FAS 19, Paragraph 221) or, through the impairment test, indirectly, as explained in this chapter's first footnote. According to Oi5.138(h),

> if a part of the interest in an unproved property is sold, even though for cash or cash equivalent, substantial uncertainty usually exists as to recovery of the cost applicable to the interest retained. Consequently, the amount received shall be treated as a recovery of the cost.[66] However, if the sales price exceeds the carrying amount of a property whose impairment has been assessed individually in accordance with paragraph .119, or exceeds the original cost of a property amortized by providing a valuation allowance on a group basis, gain shall be recognized in the amount of such excess.

Thus, proceeds from the unproved property sale are first considered a return of capital. If proceeds from sale of a portion of the property exceed the total carrying value of the entire property on which individual impairment has been recorded, or exceed the total cost of a property on which group impairment has been recorded, the excess of proceeds over net book value will be recognized as a gain.

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[66]Oi5 Note 4 mentions that the unrecovered cost is subject to impairment assessment.

To illustrate this point, assume a successful efforts company owns Lease 15074 originally costing $1,000,000 and having a $600,000 impairment allowance on an individual basis. An undivided three-fourths interest (having a $300,000 net book value) is sold for $380,000. No gain (or loss) will be recorded, because the sales proceeds are less than the entire property's $400,000 net book value. The proceeds of $380,000 will be treated as a recovery of capital.

101	Cash	380,000	
	211 Unproved Leaseholds		380,000

To record sale of three-fourths interest in Lease 15074 for less than the lease's $400,000 net book value.

On the other hand, if the three-fourths interest in the property were sold for $820,000, a gain of $420,000 would be recognized. In the illustrative entry below, a nominal amount of $10 is left in the Unproved Leaseholds account for control purposes. Thus, the gain recognized is $420,010.

101	Cash	820,000	
216	Allowance for Impairment of Unproved Properties	600,000	
	211 Unproved Leaseholds		999,990
	620 Gains on Property Sales		420,010

To record sale of three-fourths interest in Lease 15074.

Earlier it was mentioned that a loss on the sale of unproved property is recognized either directly (FAS 19, Paragraph 221) or indirectly through the impairment test. If the loss is recorded directly, the remaining cost may still need to be reduced for some impairment. For example, assume that unproved leasehold 15075 cost $1,000,000 and that individual impairment of $600,000 has been provided on the property by a successful efforts company. Three-fourths of the working interest (having a $300,000 net book value) is sold for $180,000. If the loss on sale is recorded, the remaining $100,000 of net capitalized costs would have an indicated value of only $60,000, implying an impairment of $40,000. A loss on sale and the impairment on the remaining interest should be recorded as follows:

101	Cash	180,000	
219	Allowance for Impairment . . . of Unproved Properties	450,000	
930	Losses on Sales of Property	120,000	
	211 Unproved Leaseholds		750,000

To record sale of three-fourths interest in Lease 15075.

806	Impairment of Unproved Leasehold Cost	40,000	
	219 Allowance for Impairment . . . of Unproved Properties		40,000

To recognize lease impairment on Lease 15075.

On the other hand, if impairment is recorded on a group basis, no further impairment may be necessary because the total value of properties in the group may exceed the net book value of the properties.

A full cost company would generally treat the proceeds from sale of unproved properties as a recovery of cost, as illustrated in the latter part of this chapter.

SALES OF UNPROVED NONOPERATING INTERESTS

Although the entries illustrated above all deal with sales of unproved working interests, the same general rules apply to sales of nonoperating interests, basic royalties, overriding royalties, net profits interests, and production payments (if production payments are classified as mineral interests). The only complicating factor involving the sale of a nonoperating interest arises when the interest is carved out of the working interest and assigned.

Sale of an Entire Unproved Nonoperating Interest

If the entire nonoperating interest in an unproved property is sold, the same rules apply as for working interests. For a successful efforts company, if the property is subject to an individual impairment test, the difference between the net book value of the interest and the selling price is treated as gain or loss. On the other hand, if the nonoperating interest is part of a group impairment arrangement, any sales proceeds not in excess of the original cost of the interest are treated as recovery of cost. If proceeds exceed cost, the difference is recognized as gain. For example, suppose that an unproved overriding royalty interest (ORRI) has a recorded cost of $16,000 and has been included in a group on which impairment is being recorded. The unproved ORRI is a one-eighth interest in a 640-acre lease. Three-fourths of the ORRI (equating to a 3/32 net revenue interest in total production) is sold to a purchaser for $15,200. The following entry reflects the SEC's guidelines for recording the sale:

101 Cash	15,200	
213 Unproved Royalties and Overriding Royalties		15,200

To record sale of three-fourths of our one-eighth overriding royalty interest.

On the other hand, if the sales price of the interest sold had been $30,000, a gain of $14,000 would have been recognized.

A full cost company treats proceeds from sale of nonoperating interests as recovery of capitalized cost of the full cost pool.

Sale of a Carved-Out Nonoperating Interest in Unproved Property

The Oi5 rules on conveyances make no distinction in the accounting treatment to be given to the sale of a fractional share of a working interest and that to be given to the sale of a carved-out nonoperating interest in an *unproved* property. In both cases, a successful efforts company is to treat proceeds as recovery of cost until the book value (or original cost, if group impairment is used) of the property has been recovered; any excess is treated as gain. A loss on sale of a fractional share of a nonoperating interest may be recognized (consistent with this chapter’s first footnote).

A full cost company treats proceeds from such sales as recovery of cost.

Conveyance of a Working Interest with Retention of a Nonoperating Interest

Conveyance for a Pooling of Assets. Oi5.138(b) provides that the retention of a nonoperating interest, such as an override, when assigning a working interest *in return for drilling, development, and operation by the assignee* is a pooling of assets in a joint undertaking for which the assignor shall not recognize gain or loss. The assignor's lease cost becomes the cost of the retained nonoperating interest.

Subleases of Unproved Properties. A sublease occurs whenever the working interest owner transfers the operating rights to another party for a cash or cash-equivalent consideration and retains an overriding royalty, a net profits interest, or a production payment that is considered to be equivalent to an overriding royalty. (See Chapter Twenty-Two for a discussion of production payments.) Under Oi5.138(h) a subleasing transaction is treated in the same way as the sale of part of an interest in an unproved property, i.e., the unrecovered book value (or original cost, if group impairment is used) of the working interest is assigned to the nonoperating interest retained.

For example, if OOC, which uses the successful efforts method, assigns for $300,000 an undeveloped lease that originally cost $1,000,000, and on which an individual impairment allowance of $600,000 has been established, and OOC retains an overriding royalty of one-sixteenth of total production, the appropriate entry is as follows:

101	Cash	300,000	
219	Allowance for Impairment	600,000	
213	Unproved Royalties and Overriding Royalties	100,000	
	211 Unproved Leaseholds		1,000,000

To record sublease.

The unproved ORRI retained would be subject to the impairment test. A question arises if, as is likely to happen, the overriding royalty from a property on which individual impairment has been recorded is to be placed in a group of unproved properties for impairment purposes. Should further impairment be recorded on the overriding royalty before it is transferred to the group? It would seem proper that if the value of the override clearly is substantially less than the residual book value assigned to it, a write-down to its fair value should take place at the time of the sublease because the decline in value actually applies to the working interest transferred. On the other hand, if individual impairment is to be continued on the overriding royalty interest, impairment will be determined as in the previous manner, and no immediate impairment may be necessary.

When an *unproved* working interest that is part of a group of properties on which impairment is being recorded is subleased, and an overriding royalty is retained, presumably the interest retained will be included in Unproved Overriding Royalties. If proceeds from the assignment are less than the original cost of the working interest, the amount received is treated as a recovery of cost. If the consideration received is greater than the original cost of the working interest, gain would be recognized. Under the latter situation, a nominal value, such as $1, usually is assigned to the nonoperating interest for control purposes.

For example, assume that OOC, a successful efforts company, assigns the working interest in an unproved lease to another operator for a cash consideration of $16,000, retaining a one-sixteenth overriding royalty. The lease, which cost $14,000, is part of a group of unproved properties with a total cost of $2,100,000 and on which total impairment of $1,400,000 has been recorded. The entry to record the sublease, assuming a control value of $1 is assigned to the overriding royalty, would be as follows:

101	Cash	16,000	
213	Unproved Royalties and Overriding Royalties	1	
	211 Unproved Leaseholds		14,000
	620 Gains on Property Sales		2,001

To record sublease of unproved property at a gain.

If the consideration received for the assignment in the above example had been $6,000, the appropriate entry would have been as shown below:

101	Cash	6,000	
213	Unproved Royalties and Overriding Royalties	8,000	
	211 Unproved Leaseholds		14,000

To record sublease of property.

A full cost company treats the proceeds as a recovery of cost.

Retained ORRI with a Reversionary Working Interest. The holder of a retained ORRI may have the right to convert the ORRI to a future working interest in the property at an agreed-upon time or event, such as after the WI owner(s) recover their drilling and completion costs from production. The right to convert the ORRI to a working interest contingent on some future event does not change the accounting for the initial conveyance of the working interest with retention of the ORRI. Reversionary working interests may also arise without converting an ORRI, such as in farmouts, carrying arrangements, and circumstances where some working interest owners elect to *go nonconsent* and not participate in a proposed development activity, as described in Chapter Twenty-Three.

SALES OF PROVED PROPERTIES

SALE OF AN ENTIRE PROVED PROPERTY

The sale of a proved property by a successful efforts company is handled in much the same way as the sale of any other item of plant and equipment. The precise accounting treatment depends on whether the lease is being amortized on an individual basis or is part of a group of properties on which amortization is being computed.

For example, assume OOC amortizes the cost of a proved 480-acre lease on an individual lease basis. The data relating to the property on January 1, 2000 are as follows:

Leasehold cost	$200,000
Less accumulated amortization	(40,000)
	160,000
Wells and related facilities—IDC	800,000
Less accumulated amortization	(160,000)
	640,000
Wells and related facilities—Equipment	160,000
Less accumulated amortization	(40,000)
	120,000
Total	$920,000

If the entire interest in the property is sold, all balances relating to the lease are closed out, and the difference between the consideration received and the net book value of $920,000 is treated as gain or loss. If, for example, the lease is sold outright for $3,000,000, a gain of $2,080,000 will be recognized.

SALE OF AN UNDIVIDED PORTION OF PROVED PROPERTY

If only a portion of a property is sold, the accounting treatment may become more complex. Oi5.138(j) gives general guidelines for handling this situation:

> The sale of a part of a proved property, or of an entire proved property constituting a part of an amortization base, shall be accounted for as the sale of an asset, and a gain or loss shall be recognized, since it is not one of the conveyances described in paragraph .135 or .136. The unamortized cost of the property or group of properties a part of which was sold shall be apportioned to the interest sold and the interest retained on the basis of the fair values of those interests. However, the sale may be accounted for as a normal retirement under the provisions of paragraph .132 with no gain or loss recognized if doing so does not significantly affect the unit-of-production amortization rate.

Assume the sale of an undivided interest in a proved property amortized individually. A proportionate share of each related account is removed, and gain or loss is measured by the difference between the book value removed and the consideration received. For example, if on January 2, 2000, OOC sells to Samsco for $3,000,000 cash an *undivided* three-fourths share of the working interest in the 480-acre lease in the preceding example, the appropriate entry by OOC would be as follows:

101	Cash	3,000,000	
226	Accum. Amortization of Proved Properties Acquisition Costs	30,000	
232	Accum. Amort. of Intangible Costs . . .	120,000	
234	Accum. Amort. of Tangible Costs . . .	30,000	
	221 Proved Leaseholds		150,000
	231 Intangible Costs of Wells . . .		600,000
	233 Tangible Costs of Wells . . .		120,000
	620 Gains on Property Sales		2,310,000

To record sale of three-fourths interest in a lease.

SALE OF A DIVIDED PORTION OF PROVED PROPERTY

Another difficulty is created when a successful efforts company sells a *divided* interest, e.g., 320 acres of a 480-acre tract in a proved property. If the portion sold is undeveloped and the portion retained is developed, no part of the cost of equipment or IDC should be removed from the accounts. If this procedure is followed, theoretically the unamortized mineral property cost would be allocated on the basis of relative fair values between the acreage conveyed and that retained.

Some individuals interpret *the cost of the property*, as used in Oi5 conveyance rules above, to include not only the mineral leasehold cost but also the cost of wells and related facilities and equipment, so that in measuring the cost to be "apportioned to the interest sold and the interest retained," the unamortized cost of all assets related to the property would be included, even though the portion sold is undeveloped and the portion retained is developed. If this approach is followed, the value of the interest sold would presumably be the sales price, and the value of the interest retained would be the total value of the developed lease, including equipment. This interpretation may seem strange when the interest sold is the entire working interest in a proved undeveloped property that is part of an amortization group. For example, assume that eight properties, some developed and some undeveloped, in a field have been grouped for amortization but no production (or amortization) has yet occurred. Assume the unamortized balance of costs of the group is as follows:

Proved leaseholds	$ 800,000
IDC	6,000,000
Equipment	1,000,000

An undeveloped lease in the group is sold for $2,000,000, and the remaining seven leases have a fair value of $18,000,000. The appropriate entry (allocating cost on the basis of relative fair value) would be as follows:

101	Cash	2,000,000	
	221 Proved Leaseholds		80,000
	231 Intangible Costs of Wells . . .		600,000
	233 Tangible Cost of Wells . . .		100,000
	620 Gains on Property Sales		1,220,000

To record sale of proved lease.

This treatment is justified on the basis that once an amortization group has been formed, the individual leases lose their identities and one combined property replaces them.

SALE TREATED AS A NORMAL RETIREMENT

As noted in Oi5.138(j), if a portion of a property or group of properties is sold, the sale may be treated by a successful efforts company as a *normal retirement*, "with no gain or loss recognized if doing so does not significantly affect the unit-of-production amortization rate." Presumably this treatment would occur only when the quantity of reserves sold is immaterial with respect to the total reserves retained or when the selling price per unit of reserves sold does not differ significantly from the cost amortization per unit, i.e., when the deferred gain or loss is quite small.

To illustrate this distinction, assume that a proved property (or group of proved properties) has an unamortized balance of $10,000,000 and that the related proved reserves are 2,000,000 barrels, so that the pre-sale amortization rate is $5 per barrel. If a portion of the property containing 600,000 barrels of proved reserves is sold for $3,600,000 (i.e., $6 per barrel), and if no gain or loss is recognized, the remaining cost would be $6,400,000 (i.e., $10,000,000 - $3,600,000), and the remaining reserves would be 1,400,000 barrels, so that the new amortization rate would be $4.57 per barrel (i.e., $6,400,000 ÷ 1,400,000 barrels). Further assume that the portion retained had a fair value of $14,400,000 (i.e., $10.29 per barrel[67]). If the sale had not been treated as a normal retirement, the $10,000,000 total cost would have been allocated based on relative fair values. The portion sold would be allocated $10,000,000 x 36/(36 + 144) or $2,000,000. The portion retained would have an $8,000,000 book value, equating to $5.71 per barrel for the 1,400,000 remaining reserves. Treating the sale as a normal retirement significantly affects the new unit-of-production amortization rate, reducing it from $5.71 per barrel to $4.57 per barrel, a 20% change.[68]

Normally, the value per barrel of the portion sold equals the value per barrel of the portion retained, whereby an allocation of cost based on relative fair value will leave the amortization rate the same as before the sale—$5 in the example above. However, one should be careful to

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[67] It may seem odd that the portion sold had a value of $6 per reserve barrel, while the portion retained had a value of $10.29 per reserve barrel, but such disproportionate values may occur when the sold portion is largely a reversionary interest in the field's later production.

[68] FAS 19 does not define the word *significantly*. However, Oi5.158 (FAS 69, par. 8) has defined a company has having "significant" oil and gas producing activities when such activities represent 10% or more of revenue, combined operating profit, or identifiable assets. The SEC believes that individual properties are "significant" if their costs exceed 10% of a cost center's net capitalized costs (FRR 406.01.c.i at App. 1-17 in Appendix 1). Therefore, if cost recovery changes the amortization rate by more than 10%, it may be argued the change is "significant."

compare the new amortization rate to the alternative new amortization rate (not the pre-sale amortization rate) in evaluating the amortization effect of using cost recovery.

As illustrated later in this chapter, no gain or loss is recognized on such sales under full cost unless treating the proceeds as a recovery of costs would materially distort the amortization rate.

RETIREMENTS OF PROVED PROPERTIES

The surrender or release of rights in an unproved mineral property was discussed earlier. It was explained that under the successful efforts method of accounting, if an unproved property on which impairment has been recorded on an individual basis is surrendered, the property's book value is written off as an abandonment loss. On the other hand, if an unproved property is part of a group on which amortization has been provided, when the property is relinquished, its cost is charged to the Allowance for Impairment account, and no loss is recognized.

Under Oi5.132, the abandonment of *proved* mineral interests within a proved cost center is treated in the same way as the normal retirement of equipment or wells. Oi5.132 reads as follows:

> Normally, no gain or loss shall be recognized if only an individual well or individual item of equipment is abandoned or retired or if only a single lease or other part of a group of proved properties constituting the amortization base is abandoned or retired as long as the remainder of the property or group of properties continues to produce oil or gas. Instead, the asset being abandoned or retired shall be deemed to be fully amortized, and its costs shall be charged to accumulated depreciation, depletion, or amortization. When the last well on an individual property (if that is the amortization base) or group of properties (if amortization is determined on the basis of an aggregation of properties with a common geological structure) ceases to produce and the entire property or property group is abandoned, gain or loss shall be recognized. Occasionally, the partial abandonment or retirement of a proved property or group of proved properties or the abandonment or retirement of wells or related equipment or facilities may result from a catastrophic event or other major abnormality. In those cases, a loss shall be recognized at the time of abandonment or retirement.

For example, assume the following costs and accumulated DD&A for a given field:

Proved leaseholds	$ 1,000,000
Less accumulated amortization	(600,000)
	$ 400,000
Intangible costs of wells	$12,000,000
Less accumulated amortization	(7,200,000)
	$ 4,800,000
Tangible costs of wells	$ 600,000
Less accumulated amortization	(360,000)
	$ 240,000

If an item of equipment that cost $20,000 and has been used on a lease is retired and transferred to the warehouse salvage inventory, with an estimated value of $200, the appropriate entry is:

132 Inventory of Materials and Supplies	200	
234 Accum. Amortization of Tangible Costs . . .	19,800	
233 Tangible Costs of Wells		20,000

To record retirement of equipment on lease.

Similarly, if an entire proved lease included in an amortization group of properties is abandoned, no gain or loss will be recognized. For example, suppose that a lease included in the above group, with original costs of $32,000 for leasehold, $980,000 for IDC, and $63,000 for equipment, is abandoned. Salvage proceeds from equipment total $1,000. The appropriate accounting treatment would be as follows:

101Cash	1,000	
226 Accum. Amort. of Proved Property . . .	32,000	
232 Accum. Amort. of Intangible Costs . . .	980,000	
234 Accum. Amort. of Tangible Costs . . .	62,000	
221 Proved Leaseholds		32,000
231 Intangible Costs of Wells . . .		980,000
233 Tangible Costs of Wells . . .		63,000

To record abandonment of lease in amortization group.

Conceptually, if proved properties in a common geological structure are combined for purposes of computing amortization, the individual assets lose their identities. As a matter of practice, this is not literally true because the Internal Revenue Service, federal regulatory agencies, and some state agencies may require separation of costs for each property. If, however, it is not possible to determine costs applicable to individual properties, the net salvage proceeds might be credited to the Tangible Costs of Wells and Development account or to the Accumulated Amortization of Tangible Costs account. This approach achieves the same net result as removing the costs from the asset accounts and charging them to the accumulated amortization accounts.

When the last well on the last lease that is part of an amortization base is abandoned, or when the last well is abandoned on a producing lease that is being individually amortized, all asset accounts related to the properties (or property) are closed, and net book values (less any salvage proceeds) are recorded as a loss.

In Oi5.132 quoted above, provision is made for recognition of gains or losses from a catastrophic event or other abnormality. Presumably events such as fires, floods, earthquakes, hurricanes, or unusual governmental actions would be considered abnormalities, whereas such routine items as a well blowout, abandonment of a well because of excess salt water intrusion, or other events resulting from inherent risks of the industry would not be abnormalities. For example, assume that a flood occurs in the Smith field in which leases have been combined for amortization purposes, causing major destruction of equipment. Equipment that had an original cost of $250,000 is damaged and removed. Net salvage proceeds of $28,000 are received from its sale. Total capitalized equipment costs in the field are $750,000, and amortization of $375,000 has been accumulated on the equipment. A loss of $97,000 should be recognized, computed as follows:

Cost of equipment damaged	$250,000
Less accumulated amortization:	
$\frac{\$375{,}000}{\$750{,}000} \times \$250{,}000 =$	(125,000)
Imputed book value	125,000
Less salvage proceeds	(28,000)
Net loss	$ 97,000

The loss should be recorded as follows:

101	Cash	28,000	
234	Accum. Amortization of Tangible . . .	125,000	
933	Casualty Loss {*not shown in App. 5*}	97,000	
	233 Tangible Costs of Wells . . .		250,000

To record flood loss on equipment from Smith field.

SALES AND ABANDONMENTS UNDER THE FULL COST METHOD

Under the full cost method accepted by the SEC, all oil and gas properties in each country are combined into a common *pool* and, conceptually, each property loses its separate identity. Thus, sales and abandonments of properties are generally treated as adjustments of capitalized costs. No gains or losses are recognized. Reg. S-X Rule 4-10 (c)(6)(i) includes these rules:

> The provisions of paragraph (h) of this section, "Mineral property conveyances and related transactions if the successful efforts method of accounting is followed,"[69] shall apply also to those reporting entities following the full cost method except as follows:
>
> (i) Sales and abandonments of oil and gas properties. Sales of oil and gas properties, whether or not being amortized currently, shall be accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center. For instance, a significant alteration would not ordinarily be expected to occur for sales involving less than 25 percent of the reserve quantities of a given cost center. If gain or loss is recognized on such a sale, total capitalized costs within the cost center shall be allocated between the reserves sold and reserves retained on the same basis used to compute amortization, unless there are substantial economic differences between the properties sold and those retained, in which case capitalized costs shall be allocated on the basis of the relative fair values of the properties. Abandonments of oil and gas properties shall be accounted for

[69]The reference to deleted paragraph (h) of Reg. S-X Rule 4-10 is presumed to mean Oi5.133 through Oi5.138 (on conveyances under successful efforts accounting) which replaced Reg. S-X Rule 4-10(h).

> as adjustments of capitalized costs, that is, the cost of abandoned properties shall be charged to the full cost center and amortized (subject to the limitation on capitalized costs in paragraph (b) of this section). [Authors' Note: The limitation on capitalized costs appears in Reg. S-X Rule 4-10(c)(4).]

SEC Staff Accounting Bulletin 47 (SAB 47) made it clear that the 25 percent rule is merely a general guide.[70] The test to be applied in determining whether gain or loss should be recognized is whether a significant distortion of the amortization rate would result if proceeds were treated merely as a recovery of cost—similar to the successful efforts rules for treating a sale as a normal retirement.

Substantial economic differences between the properties sold and those retained exist when the fair value per reserve boe of properties sold is substantially different from the fair value per reserve boe of properties retained. Such differences can arise, for example, (1) where production life is substantially different, (2) where expected prices differ substantially because of quality or location, (3) where degree of development of the reserves sold and of those retained is not comparable, or (4) where production costs differ widely. In such cases capitalized costs should be allocated on the basis of the relative fair values of the properties, although this requirement may necessitate a rather complex and difficult calculation because of the inability to readily arrive at a *fair value* of the properties retained.

To illustrate the concepts of significant alteration and substantial economic differences, assume that a full cost pool's gross capitalized costs are $300 million, accumulated amortization is $100 million, and the reserves in the cost center are 25 million barrels. Assume for simplicity that future development costs and future net DR&A costs are zero. The current amortization rate is $8 per barrel, i.e., ($300 - $100)/25. Certain properties, containing 7.5 million barrels of the estimated reserves, are sold for $37.5 million ($5 per barrel). Assume that the fair value of the remaining properties is $150 million ($8.57 per barrel).

In this example, substantial economic differences exist as evidenced by the $5 per barrel value of properties being sold versus $8.57 per barrel for retained properties. Allocating the $200 million net book value on the

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[70] SAB 47 stated, "A significant alteration could also occur in other cases, for instance, if 10 percent of the reserves were sold for an amount equal to 50 percent of the capitalized costs or if an unproved property within the cost center were sold for an amount significant to the total cost center."

basis of relative fair values assigns 20% or $40 million to the properties sold for a loss of $2.5 million and assigns 80% or $160 million to the properties retained for a new amortization rate of $9.14 per barrel. Deferring the loss by crediting the $37.5 million of sales proceeds against capitalized costs gives the retained properties a net book value of $162.5 million for a new amortization rate of $9.29 per barrel. Deferring the loss does not significantly alter the new amortization rate (the relationship between capitalized costs and reserves) and is allowable, despite the sold properties containing 30% of the cost center's reserves.

Changing the assumptions slightly, assume that the value of the retained properties was also $5 per barrel, allowing allocation to be based on reserves. Then 30 percent or $60 million of costs are allocated to the properties sold for a loss of $22.5 million. Treating the sale like a normal retirement (deferring the loss) still leaves a new amortization rate of $9.29 per barrel. However, if the loss had been recognized, the new amortization rate would be ($200 - $60)/17.5, or $8 per barrel, same as the old amortization rate. Deferral of the loss would not be allowable because it would significantly alter the new amortization rate ($9.29 versus $8.00).

For the preceding example, company management should not be too upset in having to recognize the loss. If all those properties were only worth $5 per barrel, but being amortized at $8 per barrel, it was probably just a short time before the full cost ceiling test would have effectively reversed any loss deferral.

Crediting sales proceeds to the cost pool should not simply be credited in the accumulated amortization account or else the property accounts accumulate costs and amortization of property no longer owned. To illustrate, assume that Fullco, a full cost company, operates only in the United States. Therefore, it has only one cost center. Total capitalized costs in the center are $364,000,000, and accumulated amortization of these costs is $120,000,000 on January 1, 2000. A summary of certain transactions in January 2000 follows:

- Unproved leases were surrendered and had a cost of $4,000,000.
- Proved leases were abandoned and had an original cost of $600,000.
- The above leases had equipment costing $380,000.
- Salvage proceeds from above equipment were $20,000.
- IDC originally incurred on abandoned leases totaled $3,900,000.

Although in the illustration above capitalized costs were associated with specific leases, this is not necessary under the full cost method, nor is it even possible in some cases. The only entry required by the information given is to reduce the carrying value of the cost pool by $20,000, the amount of salvage proceeds. This may be done by either crediting a capitalized cost account or crediting the accumulated amortization account for $20,000. Obviously, this latter approach applied over many years would result in a continuing increase in the capitalized cost accounts and the accumulated amortization account because acquisition costs are never reduced for salvaged equipment no longer owned by the company. Most companies do, however, remove the asset costs from the asset account and charge these amounts, less any net salvage against the accumulated amortization account. This procedure should be followed if possible. If this procedure is used, the summarized journal entry below would reflect the abandonments and surrenders based on the facts given above:

101	Cash	20,000	
236	Accumulated Amortization	8,860,000	
	221 Proved Leaseholds		600,000
	211 Unproved Leaseholds		4,000,000
	231 Intangible Costs of Wells . . .		3,900,000
	233 Tangible Costs of Wells . . .		380,000

Summary of abandonments and surrenders for the year.

GAINS OR LOSSES ON PROMOTIONAL ACTIVITIES

In May 1984, the SEC issued Release 33-6525, which revised Reg. S-X Rule 4-10 to make it clear that full cost companies cannot record gains or losses on the sales or promotion of unproved properties. Revised Reg. S-X Rule 4-10(c)(6)(iii)(A) now states that

> except as provided in subparagraph (c)(6)(i) of this section, all consideration received from sales or transfers of properties in connection with partnerships, joint venture operations, or various other forms of drilling arrangements involving oil and gas exploration and development activities (e.g., carried interest, turnkey wells, management fees, etc.) shall be credited to the full cost account, except to the extent of amounts that represent reimbursement of organization, offering, general and administrative expenses, etc., that are identifiable with the transaction, if such amounts are currently incurred and charged to expense.

Subparagraph (c)(6)(iii)(A) contains extremely minor exceptions to the basic rule. Thus, even though a full cost oil or gas company acquires an unproved property for the specific purpose of reselling it or transferring it to a drilling fund (or partnership) operated by the company, any gain or loss resulting from a sale or transfer is treated as an adjustment of the full cost pool. This rule is discussed further in Chapter Twenty-Four.

ACQUISITIONS OF E&P PROPERTY

ACQUISITION OF UNPROVED PROPERTY FOR CASH OR CASH EQUIVALENT

The accounting for this area was addressed in Chapter Seven.

ACQUISITION OF PROVED PROPERTY FOR CASH OR CASH EQUIVALENT

Oi5 and Reg. S-X Rule 4-10 are silent on the appropriate accounting for acquisition of proved property other than capitalizing the total purchase price. A question arises over allocation of the purchase price among the three elements of cost: mineral rights, IDC, and equipment. Conceptually the purchase price would be allocated among the three elements on the basis of relative values. Although the equipment's value can be estimated, and the sales contract often specifies the value of that element, it seems difficult to place a value on the IDC represented by the well. Because of this difficulty, and because of the federal income tax treatment required, it is common to assign to the equipment an amount equal to its fair market value and to assign the balance of the purchase price to the mineral property (leasehold) acquisition account. This is quite satisfactory if the property is fully developed so that all proved reserves on the property are being used as the basis for amortization of both the IDC and the mineral acquisition cost.

If, however, the property is only partially developed, so that reserves can be segmented into proved developed and proved undeveloped, then the aggregate acquisition cost should be allocated for financial reporting purposes as to acquisition costs (amortized over total proved reserves) and development costs (amortized over proved developed reserves) considering the relative value of proved developed reserves and proved undeveloped reserves. One reasonable approach determines IDC value by computing a lease acquisition value based on the value of a proved undeveloped barrel.

For example, a property is acquired for $1,000,000, reflecting an $800,000 value for 160,000 net barrels of proved developed reserves and a $200,000 value for 100,000 of proved undeveloped reserves. The value of equipment is $100,000. Assume first-year production of 16,000 barrels. For tax purposes, $100,000 is allocated to used equipment to be depreciated as such, and $900,000 is allocated to lease acquisition costs to be subject to tax-cost depletion based on total proved reserves. This same allocation is often used for financial reporting purposes, but understates initial amortization by amortizing the entire $900,000 over proved reserves. Of the $900,000, there is an indicated $520,000 value for lease acquisition costs (leaving $380,000 for intangible development costs) based on the proved undeveloped reserve value of $2 per barrel times 260,000 proved barrels. If $380,000 is allocated to IDC, then amortization of development costs would be (16/160) x ($380,000 + $100,000), or $48,000, in the first year. Amortization of lease acquisition costs would be (16/260) x $520,000, or $32,000. Total amortization would then be $80,000—the same as under the logical (but generally unacceptable) approach of amortizing the $800,000 value of proved developed reserves over such reserves and postponing amortization of the $200,000 until proved undeveloped reserves come on production.

BUSINESS COMBINATIONS

NEW ACCOUNTING PROPOSED

A publicly traded E&P company might acquire substantial E&P property in a business combination such as by acquiring another E&P company with an exchange of stock. Some business combinations are accounted for as a purchase, others as a pooling of assets. The FASB September 1999 exposure draft *Business Combinations and Intangible Assets* proposed elimination of the pooling accounting method. Readers of this 5th edition are encouraged to consult the final standard and any related changes in SEC staff accounting bulletins on how to account for business combinations.

CURRENT ACCOUNTING RULES, JANUARY 2000

Under the purchase method, a business combination is viewed as an acquisition of the assets and liabilities of one entity by another, with the shareholders of the acquired entity discontinuing their ownership interests or holding a reduced interest in the combined entities. Under the pooling approach, a business combination is viewed as a pooling of the ownership interests in the predecessor entities into a single entity. The assets and liabilities of the predecessor entities are simply carried forward at their previously recorded amounts, and all of the transactions of the entities both before and after the date of transactions are combined.

The basic rules of accounting for such acquisitions are contained in the AICPA's Accounting Principles Board Opinion No. 16. Although Opinion No. 16 is intended primarily for corporate entities, it appears equally applicable to partnerships. If stock of the acquiring corporation is the sole consideration given, and if certain other tests are met, pooling accounting is to be used, but, in all other instances, the purchase method must be followed. Opinion No. 16 is directed toward business combinations of two or more enterprises that are not affiliated. The parties involved in *rollups* are frequently related so that Opinion No. 16 must be considered in that context.

Staff Accounting Bulletin Topic 2, Part D (SAB Topic 2D) addresses the accounting for exchange offers when the acquiring entity is an SEC registrant, such as a corporation or a Master Limited Partnership (MLP). Technically, SAB Topic 2D does not represent authoritative SEC accounting rules but presents administrative policies that the staff has followed with respect to financial statements of oil and gas exchange offers included in filings with the SEC. The staff points out that Opinion No. 16 should be followed if the facts of an exchange offer make that opinion applicable. It also points out, however, that exchange offer transactions typically involve the exchange of interests in selected assets or operations rather than the combining of entities in their entirety. Thus, the conditions for pooling accounting laid down in Opinion No. 16 are rarely met. The SEC concludes, therefore, that when unrelated parties are involved, it is usually appropriate to record the assets on the basis of the fair value of the stock issued or the properties involved, whichever is more clearly evident. Presumably, when partnership units are issued, their fair market value would be used instead of stock value.

SAB Topic 2D, contains a chart which shows the method of accounting to be used under certain relatively simple circumstances. That chart, along with related SAB footnotes, is reproduced on the next page as Figure 21-1.

This chart indicates that purchase accounting is generally required. If a nonpublic corporation, acting as general partner in a limited partnership, forms an MLP and makes an offer to a group of related entities (that is, to partners in the limited partnership), the transaction is essentially a reorganization, and there appears to be no reason for a change in the cost basis of the property involved. However, if an existing public company whose stock has an established market value has common ownership or control with the offerees and if the offerees acquire a majority interest in the offering company, a question arises whether the transaction is a reorganization. In some situations a nonpublic general partner may be affiliated with some but not all the offerees. SAB Topic 2D indicates that in this case if the nonaffiliated offerees are not deemed *co-promoters* of the new entity, the property interests acquired from affiliated and nonaffiliated private parties should each be accounted for as though acquired in separate exchange offer transactions. Thus, it might be necessary to record the interests acquired from affiliated persons at predecessor costs while treating the interests of nonaffiliated persons as purchases recorded at the fair market value of the assets acquired.

APPLYING PURCHASE ACCOUNTING

If purchase accounting is used, properties would be recorded at the fair market value of the properties or at the value of the units issued for them, whichever is more clearly evident. If the shares are those of an existing publicly traded partnership, the market price of the units given in exchange would be an appropriate measure of the exchange. In unusual cases, for example when the public company's shares are thinly traded, the fair market value of the assets acquired may be a more appropriate measure of cost to be used in recording the properties.

Figure 21-1: Chart from SAB Topic 2, Part D
(Caution: A 1999 FASB Exposure Draft has proposed elimination of pooling accounting.)

Condition	Public Company[1]	Nonpublic[2]
Pooling of interest conditions are met (extremely rare)	Pooling of interests accounting	Same
High degree of common ownership or common control between issuing corporation and offerees[3]	Purchase accounting based on fair value of stock	Reorganization of entities under common control
All other, i.e., without common ownership or control	Purchase accounting based on fair value of stock[4]	Purchase accounting based on fair value of properties

[1] Issuing corporation is an existing public company before the exchange offer with an established market for its stock (includes situations involving use of a shell company established by a public company).
[2] Issuing corporation is not public prior to the exchange offer and thus has no established market for its stock.
[3] Common control ordinarily exists where the issuing corporation acts as general partner for the offeree partnership(s). Where all the following conditions apply, common control will be considered to exist between the issuing corporation and offerees, even though the issuer does not exercise the same legal powers as a general partner:

a. The issuer or its survivor initially acquired the property for exploration and development, *and*
b. Other investors were of a passive nature, solicited to provide financing with the hope of a return on their investment, *and*
c. The issuer or its survivor has continued to exercise day-to-day managerial control.

[4] In rare instances, such as when the property interest owners accepting the exchange offer acquire a majority of the voting shares of the company emerging from the exchange transaction, reorganization accounting may be considered appropriate. In such cases, the particular facts and circumstances should be reviewed with the [SEC] staff.

If the exchange company is a newly formed company, the properties should generally be recorded at their fair values, based on an appraisal of the properties. The fair value amount may or may not be the same as the exchange value computed in determining the shares to be offered each offeree. A deferred tax liability or asset should be recognized for differences between the recorded values and tax bases of assets and liabilities per SFAS 109, Paragraph 30.

AUDITED STATEMENTS OF COMBINED GROSS REVENUES AND LOE

In exchange offers, full historical financial statements of the acquiree are generally required in the registration filing. However, when properties and not companies are being acquired, such financial statements do not exist. SAB Topic 2D, Question 8, provides that when full financial statements of the E&P acquiree are not available, the staff may permit presentation of audited statements of combined gross revenues and direct lease operating expenses for all years in which an income statement would otherwise be required. Prior consultation with the SEC staff is recommended.

OVERRIDING ROYALTY CONVEYANCES

This chapter has already addressed accounting for some conveyances of nonoperating interests. This section summarizes such accounting for overrides and explains accounting for other types of ORRI conveyances.

SALES OF OVERRIDES

Override Sale from Unproved Property

This chapter has previously explained accounting for the sales of nonoperating interests, such as overrides, from *unproved* properties. In general, a sale is treated as a recovery of cost until the book value (or original cost if group impairment is used) of the original property has been recovered; any excess is treated as a gain.

Override Sale from Proved Property, No Working Interest Retained

When an override, or a portion of an override, is sold in a proved property with no retention of a working interest, the accounting is the same as for the sale of a working interest previously addressed in this chapter. In general, a sale of the entire override is the sale of an entire proved property interest whereby gain or loss is recognized for successful efforts and generally deferred for full cost. When an undivided portion of an override is sold, the seller recognizes gain or loss and measures the gain or loss by allocating the override's book value between the portion sold and the portion retained based on their relative fair values.

Override Sale Carved from a Working Interest in Proved Property

Oi5 conveyance rules seem unclear on how to account for the sale of an ORRI (or other nonoperating interest) carved from a working (operating) interest. Consider all the following rules:

- Oi5.136(b) does not allow gain recognition for sales of a part of interest owned if the seller has a substantial obligation for future performance, e.g., to operate the property without proportional reimbursement for operating costs applicable to the interest sold.
- Oi5.138(j) provides that the sale of part of a proved property shall be accounted for as a sale of an asset with gain or loss recognized. Gain or loss is measured by apportioning book value to the asset sold and the asset retained in proportion to their fair values.
- Oi5.138(j) and its reference to Oi5.136(b) add that a sale of part of a proved property is not part of an interest owned for which the seller has substantial obligation for future performance, such as operating the property without proportional reimbursement for that portion of the drilling or operating costs applicable to the interest sold. However, the sale of an ORRI carved from the working interest of a proved property does leave the seller with substantial obligation of future performance (paying 100% of the related costs for a reduced share of revenues).
- Oi5.138(k) provides that for the sale of a working interest and retention of an ORRI, the accounting is the same as in Oi5.138(j).
- Oi5.138(a) on conveying a VPP carved from a retained working interest does not allow gain recognition because the seller has a

substantial obligation for future performance, i.e., operating the property without proportional reimbursement for operating costs.

The question now becomes how to apply these rules given the substance of the transaction. Consider the following:

1. An outright sale for cash of an ORRI carved from a working interest is the partial sale of a mineral interest.
2. The buyer has purchased an interest in the reserves of the working interest owner. The reserves pertaining to the ORRI are no longer included in the seller's reserve base.
3. The working interest owner has the obligation for substantial future performance to operate the property and bear all operating costs relating to the ORRI sold.

Therefore, the rules of Oi5.136(b) appear to be most applicable, whereby a loss is recognized but not a gain at the time of conveyance. (See footnote 72.) The gain or loss must be measured to determine whether (1) a loss exists and must be recognized or (2) the sale proceeds can simply be credited to the cost of the asset. Under the guidance of Oi5.138(j), gain or loss is measured by apportioning book value to the asset sold and the asset retained, in proportion to their fair values. The following example illustrates the apportioning method.

Assume OOC owns a working interest with a book value of $100,000. It then sells a ten percent ORRI for cash in the amount of $40,000. The remaining WI is evaluated to have a fair market value of $120,000. The ten percent ORRI has 25 percent of the total fair value of the property [40,000/(40,000+120,000) = 25%]. Under these circumstances, a gain is calculated in the amount of $15,000 [i.e., $40,000 – (.25 x $100,000)], which cannot be recognized. If, on the other hand, the sale was in the amount of $20,000 and the fair market value of the remaining working interest was $60,000, the override's allocated cost would be $25,000 for a recognized loss of $5,000. The retained working interest would be subject to FAS 121 accounting for impairment, addressed in Chapter Eighteen.

Override Sale Treated as a Normal Retirement

As explained earlier in this chapter, Oi5.138(j) allows for the "sale of part of a proved property, or of an entire proved property constituting an amortization base . . . . [to] be accounted for as a normal retirement under the provisions of paragraph .132 with no gain or loss recognized if doing so does not significantly affect the unit-of-production amortization rate." The specific rule does not preclude such accounting for a sale of an override in proved property; however, the optional accounting (as a normal retirement) would have limited application:

- The optional accounting provides no positive income effect if the override is sold at a gain.
- The income effect is no different if the gain must be deferred anyway because a working interest was retained.
- Using the optional accounting to defer a loss (by charging the loss to the cost of the retained interest) would be of little or no value if FAS 121 accounting for impairment requires a write-down of the cost of the retained interest to fair value.
- In many cases, deferral of the loss would significantly affect the unit-of-production amortization rate whereby normal retirement accounting may not be used.

As discussed later in this chapter, normal retirement accounting (deferral of gain or loss) is not available to a conveyance of a working interest with retention of an override.

CONVEYING AN OVERRIDE TO A LENDER

In some instances, a company will convey an overriding royalty interest (ORRI) in a particular proved property in order to obtain a loan commitment from a financial institution. Such an ORRI is conveyed to obtain more favorable terms on the loan and is similar to obtaining a discounted loan. Therefore, it would be appropriate to remove the value of the ORRI from the oil and gas properties classification and treat it as a debt discount, which in effect allows the ORRI to be amortized over the life of the loan.

For example, a company wishes to obtain financing from a bank in the amount of $20,000,000 at seven percent APR repayable in ten years. The bank will loan the money only at ten percent. The company offers the bank an ORRI having an estimated fair value of $600,000 and carved from a working interest. Although the income statement effect is as if the money were loaned at ten percent, the cash flow effect to the company is a seven percent loan, and the general entry to record the loan can be summarized as follows:

101	Cash	20,000,000	
408	Debt Discount	600,000	
	401 Notes Payable		20,000,000
	201 Oil and Gas Properties (assuming full cost accounting)		600,000

To record debt proceeds and reclass ORRI conveyance.

Under full cost, the property asset accounts are typically credited with the fair value of the debt discount, and no gain or loss is recognized. Under successful efforts, a loss may be recognized, but not a gain, for the conveyance of an override carved out of a retained working interest.

CONVEYING AN OVERRIDE TO A KEY EMPLOYEE

In some instances, companies have agreements with key employees to hold, on their behalf, a carried working interest or a net profits interest which is thus conveyed in substance to said key employees, but title may not formally transfer until after certain future economic events take place with regard to specific properties or investments. Normally, the conveyance occurs before the property becomes proved. At the time of these agreements, the value of the conveyance is usually nominal and immaterial, but in theory, the conveyance should be recorded in the same manner as the conveyance of an ORRI to a lender, except that wage expense is debited rather than debt discount, and the rules for unproved property conveyances apply.

RETENTION OF AN OVERRIDE WHEN A WORKING INTEREST IS CONVEYED

Override Retention in an Unproved Property

The accounting was previously explained in an earlier chapter subsection entitled *Conveyance of a Working Interest with Retention of a Nonoperating Interest*.

Oi5.138(b) provides that the retention of a nonoperating interest, such as an override, when assigning a working interest *in return for drilling, development, and operation by the assignee* is a pooling of assets in a joint undertaking for which the assignor shall not recognize gain or loss. The assignor's lease cost becomes the cost of the retained nonoperating interest.

If the working interest is sold for *cash* or *cash equivalent* and an ORRI is retained, the conveyance is a sublease of unproved property whereby recoverability of the cost assigned to the ORRI in *unproved* property is uncertain, and sales proceeds are credited against the cost with any excess over cost recognized as a gain.

Override Retention in a Proved Property

Oi5.138(k) provides that the sale of a working interest with retention of a nonoperating interest shall be accounted for as the sale of an asset and "any gain or loss shall be recognized" under successful efforts. Reg. S-X Rule 4-10(c)(6)(i) generally requires deferral of gain or loss for full cost accounting.

The seller measures the gain or loss by allocating the property book value between the portion sold and the portion retained based on their relative fair values.

Oi5.138(k) mirrors Oi5.138(j) except that no mention is made of the option to account for the conveyance as a normal retirement. The language of Oi5.138(j) and Oi5.138(k) suggests that *normal retirement accounting* is not an available option for the sale of a working interest with retention of a nonoperating interest.

TERM OVERRIDES

Term overrides are overrides that do not extend to the economic life of the property and are of shorter duration than the underlying working interest. Term overrides may be limited in terms of quantity or in terms of time. Generally, term overrides are in substance production payments. If so, they are accounted for as production payments (either as volume production payments or as loans) addressed in Chapter Twenty-Two *Production Payments and Net Profits Interests*.

Sometimes a conveyance agreement will refer to the conveyed interest as an override, a royalty, a term override, or some similar term when in substance the conveyed nonoperating interest is a production payment or even a net profits interest. The accountant must be careful to record the substance of the conveyance regardless of the name given to the conveyance by the property interest seller or buyer.

GENERAL TAX TREATMENT OF SALES AND LEASES

For federal tax purposes there is a very important distinction between *sales* and *leases* (including subleases). In a leasing transaction the entire amount of consideration received (other than that applicable to equipment sold if a developed property is subleased) is ordinary income that may be subject to depletion for tax purposes. For example, if OOC owns an unproved lease with a basis of $50,000 and assigns the working interest to Developco for $180,000, retaining a one-eighth overriding royalty, the entire $180,000 is ordinary income to OOC. OOC assigns the $50,000 cost less any cost depletion that might be allowable on the $180,000 bonus as the basis of the override retained. For tax purposes a transaction is considered to be a lease if the working interest is assigned for cash or cash equivalent and a royalty or overriding royalty (or in certain cases a production payment) interest is retained. If a developed property is subleased, consideration received is first treated as sale of equipment equal to the equipment's fair market value, with the remaining consideration treated as leasehold bonus.

A sale transaction is deemed to have occurred when (1) all of the interest in a property is sold, (2) the type of interest sold is the same as that retained (e.g., a fractional part of a working interest is sold), or (3) the working interest is retained but a royalty interest, overriding royalty interest, or net profits interest is carved out and assigned. In a sale transaction, the seller allocates the basis between the interest retained (if any) and the interest sold, and recognizes gain (or loss) to the extent the sales proceeds exceed the basis allocated to the interest sold. If a nonoperating interest is carved out and sold, allocation is based on the relative fair value of the interest sold and of the interest retained.

Chapter Twenty-Two

PRODUCTION PAYMENTS AND NET PROFITS INTERESTS

Chapter Twenty-One addressed the Oi5.138 general accounting rules for conveyances of oil and gas properties. Chapter Twenty-Two focuses on conveyances of production payments and net profits interests.

ACCOUNTING BASED ON THE ATTRIBUTES OF OWNERSHIP

The proper accounting depends on the substance of the conveyance and not on the terminology in the conveyance agreement or used by the parties.

In evaluating a transaction's substance, it is helpful to determine what attributes of ownership the *seller* and *buyer* are assuming in the conveyance. An owner assumes the risks of ownership—primarily risks of future price changes and risks that future production will vary from expected production. There are four principal types of petroleum property *conveyances* in terms of ownership risks:

- **The Loan**: The *seller* retains substantially all pricing and production risks. The *buyer* has few or no pricing and production risks. The contractual interest involved is expressed in dollar terms, with either (1) the underlying expected cash flow from which the obligation is to be repaid being significantly greater than the contractual obligation or (2) the amount of the obligation being guaranteed by the *seller*. In substance the *seller* is not selling, but rather borrowing.
- **The Prepaid Commodity Sale or *Prepaid***: The seller retains all, or substantially all, production risks; the buyer assumes all, or substantially all, pricing risks. In the *prepaid*, the buyer of oil or gas prepays before it is delivered. The seller is selling oil or gas in advance and will buy oil and gas if necessary to meet its commitments to deliver a fixed quantity of oil or gas to the buyer in the future. For the typical conveyance, the seller debits cash and credits deferred revenue but does not reduce proved reserves or recognize a sale of a mineral interest.

- **The Volume Production Payment (VPP)**: The buyer assumes significant production risk and assumes all, or substantially all, pricing risks. The VPP differs from a prepaid in that a VPP requires the buyer to receive specified quantities from specified future production. If such production is inadequate, the seller has no obligation to make up for the shortfall. Hence, the VPP is treated as a sale of a mineral interest. Special rules are specified in Oi5.138(a) whereby for a VPP conveyance, the seller debits cash and credits deferred revenue (as for a prepaid) but treats the conveyance as a sale of a mineral interest, including any related proved reserves. For sellers using full cost accounting, the practice is to credit deferred revenue despite Reg. S-X Rule 4-10 language suggesting that proceeds may sometimes be credited to the full cost pool (see page 551).
- **The Outright Sale of a Mineral Interest**: The buyer assumes all or substantially all of the seller's ownership risks. The seller debits cash, credits property accounts, and recognizes gain or loss to the extent allowed under successful efforts or full cost accounting, as applicable.

Figure 22-1: Conveyance Types Based on Who Assumes the Risks of Ownership

	Who Assumes	
Conveyance Types	Production Risks	Pricing Risks
Loan, in substance	Seller	Seller
Prepaid commodity sale	Seller	Buyer
Volume production payment	Buyer, mostly	Buyer
Outright sale	Buyer	Buyer

PRODUCTION PAYMENTS

A production payment is an obligation of its grantor and a right of its holder for the grantor to pay the holder a specified portion of production proceeds or to deliver a specified portion of specified production before the production is expected to cease. In either form, the holder has no obligation to pay operating costs and looks to specified production for a limited period to receive cash or marketable production. Accounting for the creation of a production payment depends in part on whether the E&P company conveyed the production payment or, in conveying a working interest, retained the production payment.

CONVEYED PRODUCTION PAYMENTS

Production payments are typically conveyed in return for immediate receipt of cash. The conveyance transaction is, or resembles, a financing arrangement. Financing arrangements commonly entail the mineral property owner pledging production or proceeds from production to collateralize repayment of funds advanced by the other party to the financing arrangement.

Complexities in accounting treatment arise because the financial markets are becoming more creative in designing instruments for investors. In some situations, funds advanced are equivalent to loans, whereas in other cases they represent sales of oil and gas interests or advance payments for the purchase of future production. Sometimes, subtle wording differences in the agreement can actually change the nature of the transaction to a mineral conveyance, even though the types of transactions appear similar and are referred to by the same name.

The Emerging Issues Task Force of the Financial Accounting Standards Board has addressed the accounting implications in EITF Issue No. 88-18 entitled *Sales of Future Revenues*:

> The Task Force reached a consensus . . . that classification as debt or deferred income depends on the specific facts and circumstances of the transaction. The Task Force also reached a consensus that the presence of any one of the following factors independently creates a rebuttable presumption that classification of the proceeds as debt is appropriate:
>
> 1. The transaction does not purport to be a sale (that is, the form of the transaction is debt).

2. The enterprise has significant continuing involvement in the generation of the cash flows due the investor (for example, active involvement in the generation of the operating revenues of a product line, subsidiary, or business segment).
3. The transaction is cancelable by either the enterprise or the investor through payment of a lump sum or other transfer of assets by the enterprise.
4. The investor's rate of return is implicitly or explicitly limited by the terms of the transaction.
5. Variations in the enterprise's revenue or income underlying the transaction have only a trifling impact on the investor's rate of return.
6. The investor has any recourse to the enterprise relating to the payments due the investor.

The basic premise of the Task Force's discussion in EITF Issue 88-18 is that financing arrangements that are advances for future production should be classified as debt unless conditions justify otherwise. As illustrated later in this chapter, many conveyed production payments are indeed borrowings. However, conveyance of a volumetric production payment (in which the grantor pledges to deliver certain quantities out of future production, free and clear to the lender) is regarded as a sale of future production whereby the sales proceeds are classified as deferred (or unearned) revenue for successful efforts accounting and, in practice, for full cost accounting (see page 551).

To better understand conveyed production payments, four general types of financing arrangements are discussed below:

1. Production loans,
2. Guaranteed recoupable exploration advances,
3. Conveyed production payments for repayment of loans, and
4. Conveyed production payments payable in product.

Production Loans

A basic financing arrangement is the *production loan*, by which the E&P company obtains funds from a bank or other financing institution, to be repaid, with interest, out of the company's production proceeds from a specified property or properties. If the production proceeds are not sufficient to repay the advance, other funds generally must be used by the operator to repay the lending institution. A production loan transaction has no effect on the E&P company's revenue accounting; when payments are made on the loan, they are treated in the same way as repayment of any other debt. The E&P company includes all of the working interest's share of reserves in computing amortization and in making reserve disclosures because the lender is not deemed to own a mineral interest.

Guaranteed Recoupable Exploration Advances

Historically, a gas pipeline company which needed gas supplies would advance funds to an operator to be used in exploration or in developmental drilling in return for the right to purchase all or part of the gas produced from the properties involved. This conveyance gives the advancer of funds the right to purchase production from the properties on which the funds are to be spent, either at a specified price per unit or at the prevailing market price at the time of production, with the advance offset against the purchase price. In addition, the repayment of the advance can be satisfied from the general assets of the E&P company, as well as from production of other properties specifically pledged, if the advance has not been recouped within a specified period. Given the enormous supplies of gas available today, this type of advance is now extremely rare, and its mention is for illustration of a financing arrangement described in Oi5.134.

Oi5.134 stipulates that a recoupable advance is to be accounted for as a receivable by the advancer of funds and as a payable by the operator:

> Enterprises seeking supplies of oil or gas sometimes make cash advances to operators to finance exploration in return for the right to purchase oil or gas discovered. Funds advanced for exploration that are repayable by offset against purchases of oil or gas discovered, or in cash if insufficient oil or gas is produced by a specified date, shall be accounted for as a receivable by the lender and as a payable by the operator.

As for a production loan, the E&P company includes all of the working interest's share of reserves in computing amortization and in making reserve disclosures because the lender is not deemed to own a mineral interest. Similarly, total working interest revenues are reported by the E&P company.

Production Payments Conveyed as Security for Repayment of Loans

A variation of the arrangements described above is a true production payment, under which the operator *carves out* an interest in the minerals from a specific property or properties and *sells* it to a financing institution (conveys the production payment as the source of repayment of the loan). The financing institution will receive a specified fractional share of proceeds from production from the property until the principal amount advanced, plus interest, is recovered. Satisfaction of payment from the related production is reasonably assured, and the lender bears little risk of nonpayment due to production or price declines.

Several features of such a production payment distinguishes it from the traditional production loan. The most important is that repayment is to be made from the proceeds of production *when, if,* and *as produced*. This means that this type of financing arrangement is nonrecourse, and the advance is repaid only from the specified proceeds of production from specific properties. Neither other assets nor the general credit of the E&P company provide collateral to the creditor. Obviously a financing institution is likely to lend money under such circumstances only if the property has a good history of production, if the amount of the loan is a small part of the value of estimated total reserves to be produced from the property, and if there is a favorable interest rate. Clearly the intention of the E&P company in this type of transaction is to obtain financing, not to sell future production. As with the traditional production loan, the E&P company (not the lender) retains substantially all risks of ownership of the reserves. Thus, a production payment carved out of a producing property is treated as a receivable by the financing institution and as a payable by the E&P company. Oi5.134(b) contains the following provision:

> Funds advanced to an operator that are repayable in cash out of the proceeds from a specified share of future production of a producing property, until the amount advanced plus interest at a specified or determinable rate is paid in full, shall be accounted for as a borrowing. The advance is a payable for the recipient of the cash and a receivable for the party making the advance. Such transactions . . . are commonly referred to as production payments.

All of the production is reported as revenue by the E&P company, which includes all the working interest's share of reserves in the required reserve disclosures. Payments of interest and principal are recorded in the same manner as payment on any other loan. It would appear appropriate to consider the payment to be a long-term or short-term obligation on the same basis as any other obligation, although *Accounting Research Bulletin No. 43* suggests that only that amount accrued at the balance sheet date should be classified as a *current* liability. Thus production payments by their nature are generally long-term obligations. A reclassification of a portion of the production payment to current liabilities should coincide with any accrual for production revenues that pertain to satisfaction of the production payment.

Conveyed Production Payments Payable in Product

A production payment payable in product can take two forms:

1. Payable in specified quantities from specified production and nonrecourse, or
2. Payable in product not limited to specified production (whereby the holder has recourse to receive payment through other means available to the E&P company).

Such production payments are usually created from proved developed producing property.

The first form is a VPP described in Oi5.138(a):

> The seller's obligation is not expressed in monetary terms but as an obligation to deliver, free and clear of all expenses associated with operation of the property, a specified quantity of oil or gas to the purchaser out of a specified share of future production. Such a transaction is a sale of a mineral interest for which gain shall not be recognized because the seller has a substantial obligation for future performance. The seller shall account for the funds received as unearned revenue to be recognized as the oil or gas is delivered.[71] The purchaser of such a production payment has acquired an interest in mineral property that shall be recorded at cost and amortized by the unit-of-production method as delivery takes place. The related reserve estimates and production data shall be reported as those of the purchaser of the production payment and not of the seller. . . .

[71]For full cost accounting, the practice is to record the VPP proceeds as deferred revenue despite S-X Rule 4-10 language suggesting that in some instances the proceeds may be credited to the full cost pool (see page 551).

The second form is a prepaid, as described earlier in the chapter, that is not regarded as a mineral interest sale, since the obligation to deliver product is not solely dependent on any specified production or reserves.

Since the VPP obligation is to be satisfied solely from future production, the seller has a substantial obligation for future performance, i.e., to produce the product and pay for related production costs.[72] Thus, no gain is recognized at the time the conveyance contract is entered into. Under successful efforts accounting, the seller is deemed to have received unearned revenue to be recognized as oil or gas is delivered.

The treatment required by the purchaser of a VPP appears to be inconsistent with that required of the VPP seller. The seller is required to recognize revenues (instead of gain on the sale of a mineral property) as the oil or gas is produced. Yet the oil or gas reserves that give rise to this revenue are to be excluded from the reserves reported by the VPP seller. The VPP purchaser is also reporting revenues as the oil and gas is produced.

It would be more logical for the VPP seller to defer gain, not revenue, since the conveyance is deemed a sale of a mineral interest whereby the operator no longer owns the reserves that, when produced, generate the revenues. For a production payment from proved property, gain or loss would be based on apportioning property costs between property sold (the production payment) and property retained on the basis of relative fair value consistent with Oi5.138(j), but gain would be deferred consistent with Oi5.136 because the VPP seller is obligated to pay all associated production costs and may be obligated to continue production and pay such costs even when they exceed the operator's net proceeds after the production payment. This more logical approach is not specifically permitted due to the specific accounting for a VPP as set forth in Oi5.138(a).

A second alternative not specifically allowed is to record deferred revenue and have the VPP *seller* (i.e., grantor) deemed owner of the reserves. In other words, the VPP conveyance is not regarded as a mineral interest sale, but as the holder's prepayment for purchase of production, similar to a *prepaid*. Such accounting is appropriate for a true prepaid for which the specified future volume is not tied to specified production. For example, a prepaid would be Our Oil Company (OOC) receiving

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[72]This differs from an operator's sale of a working interest wherein the operator has a fiduciary obligation to manage future operations, i.e., to produce, but not an obligation to pay for the new owner's working interest share of production costs.

$1,000,000 today to deliver 500,000 mcf of gas over the next five years regardless of the company's production. In a prepaid, the buyer assumes price risks, but no production risks, of ownership. If necessary, OOC must buy gas in the open market to meet the prepaid obligation of delivering gas. However, a true VPP is tied to specified production, and the buyer does assume both pricing risks and some production risks. Hence, it is more appropriate to treat the true VPP as the sale of a mineral interest. The second alternative is not as supportable as the first.

To illustrate the *required* treatment under successful efforts accounting, assume that on January 2, 2000, OOC carves out and assigns for $1,000,000 a production payment of 500,000 mcf of gas from producing lease 16018 to Mid-Central Pipeline Company, to be satisfied by delivery out of the first 80 percent of the working interest's share of production. The remaining unrecovered capitalized costs of the property on that day were $295,000. During 2000, the working interest's share of production was 450,000 mcf of gas, of which 360,000 mcf were delivered to Mid-Central under the production payment agreement.

On December 31, 2000, the working interest's share of proved reserves in the ground was 2,500,000 mcf, of which 140,000 mcf belong to the production payment owner. Appropriate journal entries to summarize the pertinent facts for both parties are given below:

Our Oil Company

101 Cash	1,000,000	
430 Deferred Revenues		1,000,000
To record sale of VPP.		

430 Deferred Revenues	720,000	
602 Gas Revenues		720,000
To record earned revenue applicable to VPP [(360,000 ÷ 500,000) x $1,000,000].		

In its December 31, 2000, disclosure of proved reserve quantities, OOC would include 2,360,000 mcf (2,500,000 - 140,000) for lease 16018. The production applicable to the production payment would be ignored in computing depreciation, depletion, and amortization for 2000. Thus, the total DD&A recorded on the lease for 2000 would be $10,837, as shown in the following calculation:

$$\frac{450{,}000 - 360{,}000}{2{,}360{,}000 + (450{,}000 - 360{,}000)} \times \$295{,}000 = \$10{,}837$$

Mid-Central Pipeline Company

225 Proved Production Payments	1,000,000	
101 Cash		1,000,000
To record VPP to OOC.		
726 Amortization of Proved Property Acquisition Costs	720,000	
226 Accumulated Amortization of Proved Property Acquisition Costs		720,000

To record amortization of production payment from OOC [(360,000 ÷ 500,000) x $1,000,000].

In its disclosure of proved reserves on December 31, 2000, Mid-Central Pipeline Company would include 140,000 mcf of gas remaining to be received under the production payment.

Conveyance of a production payment can in substance be a borrowing, a VPP, or even a prepaid, depending on the terms of the conveyance. Here are five examples of conveyed production payments. The first two illustrate conveyances that are in substance borrowings. The third and fourth are VPPs. The fifth is a prepaid. In each case, at the time of conveyance, the grantor and holder reasonably expect the production payment to be paid off before the underlying property ceases production.[73]

1. A borrowing: For cash received, convey a production payment entitling its holder to $5,000 per month for four years from revenue proceeds (net of production taxes) of grantor's 20 percent working interest in the ABC lease.
2. A borrowing: For cash received, convey a production payment entitling its holder to the proceeds of 75 percent of oil production attributable to grantor's 20 percent working interest in the MNO lease until the holder receives $100,000 and interest thereon at 12 percent per annum.

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[73]In that sense, the production payment is similar to a *limited override* that will cease or is expected to cease before the working interest ceases.

3. A VPP: For cash received, convey a production payment entitling its holder to 75 percent of oil production attributable to grantor's 20 percent working interest in the ABC lease until the holder receives 20,000 barrels of oil.
4. A VPP: For cash received, convey a production payment entitling its holder to 75 percent of oil production attributable to grantor's 20 percent working interest in the ABC lease and the XYZ lease for ten years.
5. A prepaid: For cash received, convey a production payment entitling its holder to 300 barrels per month for five years from grantor's 20 percent working interest in the ABC lease provided that if at any time such production is insufficient to provide 300 barrels in any one month, grantor shall makeup the difference by delivering other oil of similar grade and quality.

In the first example, the production payment proceeds are fixed in terms of amount and timing, the holder is assuming virtually no price or production risks, and the conveyance is in substance a borrowing. In the second example, the holder is to be repaid $100,000 at 12 percent interest and assumes virtually no more price or production risks than under a bank loan with the property serving as collateral. Examples three and four fit the VPP requirement of repayment of a specified quantity from specified reserves whereby the holder assumes pricing risk and some production risk. The grantor must record the proceeds as deferred revenue and reduce its reserves by the specified quantity due the holder.

In the fifth example, the conveyance also calls for a specified quantity from specified reserves but contains a *safety net* clause so that if production is insufficient, grantor will make up the difference even if grantor has to buy oil to deliver to the holder. The holder has no production risk, only price risk. So the conveyance is in substance a prepaid. For a prepaid, the grantor still records the initial proceeds as deferred (or unearned) revenue, but the grantor is viewed as still owning the underlying reserves.

Underlying the Oi5 accounting rules for conveyances are three concepts expressed in Oi5.134 and Oi5.136 applicable to the accounting for production payments:

- Some conveyances are in substance borrowings repayable in cash or its equivalent whereby those conveyances should be accounted for as borrowings.

- If part of an interest is sold and substantial uncertainty exists about recovery of the costs applicable to the retained interest, no gain should be recognized at the time of the conveyance.
- If part of an interest is sold and the seller has a substantial obligation for future performance, no gain should be recognized at the time of conveyance.

A key to properly accounting for production payments is determining whether the facts surrounding the individual contract creating the rights and obligations cause the arrangements to fall under one of the three basic rules reviewed above.

CONVEYANCES SUBJECT TO RETAINED PRODUCTION PAYMENTS

A retained production payment is created when the owner of the working interest in a mineral property transfers that interest to a purchaser but retains an oil or gas payment that will be satisfied when, if, and as oil or gas is produced out of the working interest assigned. The production payment, which may be created out of a group of properties rather than from a single property, is nonrecourse; that is, the holder can look only to production for satisfaction. Retained payments usually arise when the lessee of a mineral property assigns that working interest to another operator, but they may also be created by the original lease contract between the mineral rights owner and the lessee.

For example, an E&P company desires to sell a producing property for $1,000,000. Another E&P company is willing to purchase the property for that price, but lacks the needed financing. The first company sells the property to the second company for $1,000,000, with the buyer paying $200,000 in cash and the seller reserving a production payment of $800,000 plus interest, payable out of 90 percent of the working interest's share of revenues that would otherwise go to the buyer.

Accounting for such a conveyance depends in part on whether the underlying property is proved or unproved and whether the retained production payment is (1) expressed in monetary terms and reasonably assured or (2) equivalent to an override.

Retained Payments Carved from Proved Properties

Expressed in Monetary Terms. The appropriate accounting treatment for a conveyance transaction creating a retained production payment expressed in monetary terms depends on whether satisfaction of the payment is *reasonably assured*. Reasonable assurance of satisfaction from a proved property exists only in those cases in which the reserves estimated to be necessary to satisfy the payment are appreciably less than the total working interest share of proved reserves in the property subject to payment.

Oi5.138(l) is rather explicit in describing the accounting treatment for retained payments expressed in monetary terms arising from the conveyance of proved properties. Oi5.138(l) specifies the treatment by a successful efforts company of a retained payment whose satisfaction is reasonably assured:

> The sale of a proved property subject to a retained production payment that is expressed as a fixed sum of money payable only from a specified share of production from that property, with the purchaser of the property obligated to incur the future costs of operating the property, shall be accounted for as follows:
>
> (1) *If satisfaction of the retained production payment is reasonably assured.* The seller of the property, who retained the production payment, shall record the transaction as a sale, with recognition of any resulting gain or loss. The retained production payment shall be recorded as a receivable, with interest accounted for in accordance with the provisions of Section I69, "Interest: Imputation of an Interest Cost." The purchaser shall record as the cost of the assets acquired the cash consideration paid plus the present value (determined in accordance with the provisions of [Current Text] Section I69) of the retained production payment, which shall be recorded as a payable. The oil and gas reserve estimates and production data, including those applicable to liquidation of the retained production payment, shall be reported by the purchaser of the property (refer to paragraphs .160 through .167). . . .

As indicated in the citation above, if satisfaction of the payment retained on transfer of a proved property is reasonably assured, the retained production payment is in substance a note receivable and should be measured and recorded in accordance with the general rules specified in

APB Opinion No. 21, which in general states that a receivable should be recorded at the discounted present value of the payments to be received. If the contract includes interest at a reasonable rate, the face amount of the payment is in its appropriate measure. For example, assume that OOC conveys to Red Company the working interest in a producing leasehold whose capitalized costs and accumulated amortization are as follows:

	Leaseholds	Intangibles	Tangibles
Cost	$ 60,000	$480,000	$ 90,000
Less accumulated amortization	(20,000)	(160,000)	(30,000)
Net book value	$ 40,000	$320,000	$ 60,000

The consideration for the transfer is cash of $1,000,000 and a production payment of $1,600,000 bearing interest at 12 percent (assumed to be a reasonable interest rate), payable out of the first 75 percent of the working interest's share of production. Satisfaction of the production payment is reasonably assured. The accounting treatment required by Oi5.138(l)(1) is as follows:

101	Cash	1,000,000	
226	Accumulated Amortization of Proved Property Acquisition Costs	20,000	
232	Accumulated Amortization of Intangible Costs of Wells and Development	160,000	
234	Accumulated Amortization of Tangible Costs of Wells and Development	30,000	
271	Notes Receivable—Production Payments	1,600,000	
	221 Proved Leaseholds		60,000
	231 Intangible Costs of Wells and Development		480,000
	233 Tangible Costs of Wells and Development		90,000
	620 Gain on Property Sales		2,180,000

To record sale of lease.

Assuming that the agreed-on value of the equipment is $70,000, the purchaser would record the transaction in the following way:

233	Tangible Costs of Wells and Development	70,000	
221	Proved Leaseholds	2,530,000	
	101 Cash		1,000,000
	404 Production Payments Payable		1,600,000
To record purchase of lease.			

Once again, the purchaser should conceptually allocate the *basket purchase price* among equipment, IDC, and mineral interest on the basis of their relative fair values. However, because of the difficulty in making an allocation between IDC and leasehold, it is customary to allocate the purchase price first to equipment (equal to its fair value) and to charge the remaining cost to the mineral interest. This treatment would also be required for federal income tax purposes.

The purchaser of the property subject to the retained production payment will record all revenues and expenses applicable to the property. Payments made to the holder of the production payment will first be allocated to interest expense in the manner specified in the contract, with the balance treated as a reduction of the principal amount of the payment. Similarly, the holder of the production payment will treat the proceeds first as interest income, with any remaining proceeds treated as recovery of the principal.

Expressed as a VPP. Oi5.138(l)(2), also explains how to handle the sale of a proved property subject to a production payment expressed as a fixed sum of money but without reasonable assurance of repayment:

> (2) *If satisfaction of the retained production payment is not reasonably assured*. The transaction is in substance a sale with retention of an overriding royalty that shall be accounted for in accordance with paragraph .138(k).

Oi5.138(m) addresses accounting for a retained VPP:

> The sale of a proved property subject to a retained production payment that is expressed as a right to a specified quantity of oil or gas out of a specified share of future production shall be accounted for in accordance with paragraph .138(k).

Accordingly, a transaction of this nature is treated in the same way as a sale of the operating interest in a proved property with retention of a nonoperating interest, such as an ORRI, discussed in Chapter Twenty-One. In essence, the sale of an operating interest in proved property, subject to (1) a retained production payment not reasonably assured, (2) a VPP, or (3) a nonoperating interest such as an ORRI, is accounted for as a sale with gain or loss recognized. Book value is allocated to the interest sold and the interest retained based on relative fair values, similar to the normal accounting for an undivided portion of an operating interest in proved property, as discussed in Chapter Twenty-One.[74]

Paragraph 232 of FAS 19 (from which the SEC drew the above rules) elaborates on this situation and more clearly states the proper accounting to be followed:

> [Paragraphs .138(l) and .138(m)] have been added to clarify that accounting for the sale of a property with retention of a production payment shall be compatible with the accounting for the sale of production payments with retention of the operating interest. A retained production payment expressed in money may sometimes be so large that it is highly improbable that the production payment will be satisfied before the reserves are fully depleted. In those situations, therefore, paragraph [.138(l)] provides that the retained production payment shall be treated as an overriding royalty interest rather than a receivable or payable.

In the preceding chapter it was pointed out that if an operating interest in a proved property is sold with retention of a nonoperating interest (e.g., an overriding royalty), the seller should allocate the cost of the proved property to the operating interest sold and the nonoperating interest retained on the basis of the fair values of those interests. To illustrate this accounting treatment for a retained production payment, assume that in the immediately preceding example, satisfaction of the production payment of $1,600,000 is not reasonably assured. Based on the known reserves, the production schedule, selling prices, costs, and appropriate discount rates, the production payment is estimated to have a fair value of $600,000. The sales proceeds are first allocated to the equipment in an amount equal to its

[74]The sale of an operating interest in *unproved* property, subject to (1) a retained production payment not reasonably assured, (2) a VPP, or (3) a nonoperating interest such as an ORRI, is accounted for as a sublease of unproved property as discussed in Chapter Twenty-One.

fair value, so that a gain of $10,000 ($70,000-$60,000) is recognized on the equipment sale. The remaining unrecovered cost of $360,000 (leasehold cost and IDC) is then allocated between the interest sold and that retained on the basis of relative fair values:

Value of interest sold (cash proceeds)	$ 930,000
Value of production payment retained	600,000
Total	$1,530,000

Cost allocable to interest sold: $\frac{\$930{,}000}{\$1{,}530{,}000} \times \$360{,}000 = \$218{,}824$

Cost allocable to production payment retained: $\frac{\$600{,}000}{\$1{,}530{,}000} \times \$360{,}000 = \$141{,}176$

Gain on sale of the mineral interest and IDC is thus $711,176 ($1,000,000 - $70,000 - $218,824). Total gain on the sale is $721,176 ($711,176 on mineral interest and IDC and $10,000 on equipment) as recorded by the following entry:

101 Cash	1,000,000	
225 Proved Production Payments	141,176	
226 Accumulated Amortization of Proved Property Acquisition Costs	20,000	
232 Accumulated Amortization of Intangible Costs of Wells and Development	160,000	
234 Accumulated Amortization of Tangible Costs of Wells and Development	30,000	
221 Proved Leaseholds		60,000
231 Intangible Costs of Wells and Development		480,000
233 Tangible Costs of Wells and Development		90,000
620 Gain on Property Sales		721,176
To record sale of property.[75]		

[75] For full cost accounting, no gain or loss would be recognized unless nonrecognition would significantly change the relationship of net capitalized cost to reserves. See the Full Cost Accounting section near the end of this chapter.

Determination of whether *satisfaction* of a retained production payment is *reasonably assured* may have a profound impact on the accounting treatment given the transaction, especially if the payment is large in comparison to the cash consideration received. If satisfaction is reasonably assured, the payment is, in effect, a monetary asset (or debt); on the other hand, if satisfaction is *not* reasonably assured, the retained production payment is equivalent to an overriding royalty interest. *Reasonable assurance* is a most subjective measure.

Retained Payments in Unproved Properties

A production payment retained on assignment of an unproved property is likely to be expressed in terms of mcf of gas or barrels of oil, so that it is considered under Oi5.138(m) as a nonoperating mineral interest. In that event, the transaction is treated as a sublease (see the preceding chapter), with cash proceeds from the transaction treated as a return of book value (or of the property's original cost, if group impairment is followed) and only unrecovered book value (or unrecovered cost) is assigned to the production payment as its carrying value. The unproved production payment is, of course, subject to the impairment test. A production payment expressed in a monetary amount is, under Oi5.138(l), conceptually a *cash equivalent* asset. However, that concept was severely restricted by the conclusion in Oi5.138(l)(2) (and in Paragraph 232 of FAS 19) that if satisfaction of a retained payment in a *proved* property is not reasonably assured, the payment takes on characteristics of a mineral interest rather than a monetary asset. Oi5.138(l) does not specifically discuss payments retained out of *unproved* properties, but by their very nature these payments have no assurance of satisfaction. It is logical, then, to conclude that payments retained out of unproved properties are equivalent to overriding royalties and should be treated as such in the manner discussed for leasing transactions in the preceding chapter.

Prepaid Price Swaps

A variation of the VPP has an oil and gas producer receiving an advance from a financial institution in exchange for the revenues from production relating to a specified volume of production for a specific time period. The producer sells its production in the normal course of business at market prices and remits the actual proceeds to the financial institution. This process differs from the traditional volumetric production payment in that the producer does not deliver production, but sells it first, then delivers proceeds to the financial institution. This variation has been characterized as a *prepaid price swap*.

Given that both price and production risks are transferred to the financial institution, the economics of the typical prepaid price swap are the same to the producer as a volumetric production payment, as defined in FAS 19. Therefore, successful efforts accounting would have the proceeds from the advance recorded as unearned revenue and amortized relative to periodic sales over the life of the agreement.

NET PROFITS INTEREST

NET PROFITS INTEREST DEFINED

Chapter Seven briefly described the terms net profits interest (NPI), retained NPI, carved-out NPI, and term NPI. This chapter will briefly address the accounting for conveyance of these four economic interests.

A net profits interest (or Net Profit Interest) is an interest in production created usually from the working interest and measured by a stated percentage of the net profits (as defined in the agreement creating the NPI) from the operation of the property.[76] The NPI holder is never obligated to pay for a share of losses; however, the net profits may be cumulative and incorporate losses from prior periods. The NPI is similar, then, to an ORRI but is measured on net profits, not revenue. The holder is not liable for net costs or losses.

For example, OOC might convey as of January 1, 2000, a net profits interest of 20 percent of the net profits from OOC's 50 percent working interest in the ABC field. The conveyance agreement defines net profits as revenue less severance taxes and other direct exploration and development costs and direct operating costs (usually net profits contracts treat outlays for exploration and development as deductible *expenses*). Amortization, indirect administration costs, interest expense, and income taxes are ignored in computing net profits. Net profits are to be cumulative. If OOC had no revenue or operating expense from the field during January 2000 but had $50,000 in development costs, there were no net profits that month, and the NPI holder receives nothing. If in February 2000 OOC's share of operations was $100,000 of revenue, $10,000 in severance taxes,

[76]The contract should also address the NPI holder's right for accounting and the right to audit the accounting, as briefly discussed in COPAS Bulletin No. 9.

and $30,000 in other direct operating expenses, then the February net profits are $60,000, and the cumulative net profits are $10,000. Therefore, OOC is to pay the NPI holder 20 percent of $10,000.

ACCOUNTING FOR CONVEYANCE OF A NET PROFITS INTEREST

Oi5 conveyance rules are silent on accounting for an NPI conveyance specifically. However, a net profits interest is a nonoperating interest whereby the accounting for conveyances involving an NPI are similar to the accounting for override conveyances discussed in Chapter Twenty-One. However, the accounting differs when the NPI is conveyed with retention of a working interest.

Unlike the sale of an ORRI carved from a retained working interest, the accounting required for sale of an NPI on proved property will typically allow for immediate recognition of any gain under successful efforts accounting. When the NPI share is based on cumulative net profits, the retained working interest holder may have a very limited future obligation, not a *substantial* obligation, to bear a cumulative loss, i.e., a disproportionate share of future development and operating costs. Absent a cumulative loss, the NPI indirectly bears the costs, since the costs determine cumulative net profit. The computation of gain itself (reflecting fair value in excess of allocated cost) is indicative that overall fair value exceeds overall book value whereby future cumulative loss to the WI holder is not expected. Under some circumstances, such as an NPI based on periodic, noncumulative net profit, the WI holder may have substantial future obligations that preclude the immediate recognition of gain.

GENERAL ACCOUNTING FOR NET PROFITS INTERESTS

Net profits interests are uncommon, and general accounting for them varies, as found in the *1999 PricewaterhouseCoopers Survey of U.S. Petroleum Accounting Practices*. Of 45 survey respondents, only 23 addressed net profit interests. The responses are summarized as follows:

	NPI Owned	NPI Obligation
Treatment of Related Revenue and Expenses:		
• Record gross, report both revenues and costs as though a WI	30%	30%
• Record net, as though an ORRI	70	52
• Record net as an operating expense	N/A	13
• Other	0	5
	100%	100%
Assignment of Reserves to Interest:		
• Assign gross reserves as though a WI	10%	30%
• Assign net reserves as though an ORRI	71	52
• Do not assign reserves	19	9
• Other	0	9
	100%	100%

Generally a company should be consistent in the way it records the net profits received or paid out and the way it assigns reserves to such net profits.

TERM NET PROFITS INTERESTS

A *term NPI* is limited to a specified time period, limited by a specified net profits amount, or limited to a specified underlying production volume. The term NPI is similar to a production payment in that both have limited economic life. Term NPIs and VPPs are attractive partly because their *sales* can often be treated as borrowings for tax purposes but sometimes may be treated for financial reporting purposes as sales, reducing the full cost pool or giving rise to deferred gain or deferred revenue. However, the accounting treatments given specific NPIs may differ greatly, depending on the term NPI characteristics as defined in the agreement.

For example, if the term NPI (1) is limited to a stated quantity, (2) is not expected to extend for the full productive life of the underlying producing properties, (3) does not require the operator to deliver products to the term NPI holder, and (4) does not put the NPI holder at risk for cash payments to the operator should the expenses exceed revenues at any time during the life of the agreement, then one could conclude that this term NPI most closely resembles a VPP. Hence, this type of term NPI could be treated as a sale of mineral interests like a VPP, i.e., recognizing unearned deferred revenue for successful efforts.

Alternatively, if the term NPI does not require quantities to be delivered and its conveyance was not in substance a borrowing, the conveyance of a term NPI could be considered a sale of a portion of a property, whereby

- for an unproved property (which would be rare), the proceeds simply reduce associated capitalized costs before any gain could be recognized, and
- for a proved property, gain (or loss) is calculated, and gain must be deferred if the seller has a substantial obligation for future performance.

Proper accounting will depend on the substance of the transaction.

ACCOUNTING RULES FOR OTHER PROPERTY CONVEYANCES

As pointed out earlier, oil and gas producers and financial markets are interested in oil and gas reserves as the basis for creation of securities or financial instruments which may be sold to investors. Cash-strapped oil and gas producers may be seeking ways to increase cash flow for a variety of reasons many of which have to do with an immediate inability to sell reserves on the open market at reasonable prices. As a result, an operator's desire to cash in its reserves in unconventional ways leads to unconventional financing methods and corresponding questions of how to account for them.

Accounting for unusual conveyances and financing methods requires consideration of the mineral conveyance accounting rules found in Oi5.133 through .138 and substantially discussed in Chapters Twenty-One and Twenty-Two. Another source of guidance is the FASB's Emerging Issues Task Force (EITF), particularly EITF's Issue No. 88-18 *Sale of Future Revenues* (EITF 88-18), discussed in the Production Payment section of this chapter.

FULL COST ACCOUNTING

Accounting for production payments under full cost is similar to that for successful efforts with two notable exceptions described below.

CONVEYANCE OF A VPP

In practice, full cost companies account for VPPs in the same way as successful efforts companies despite Reg. S-X Rule 4-10 language suggesting otherwise in some cases. Since a VPP conveyance is regarded as a sale of a mineral interest, Reg. S-X Rule 4-10(c)(6)(i) would arguably apply whereby "sales of oil and gas properties . . . shall be accounted for as adjustments of capitalized costs" with generally no gain or loss recognized “unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves . . . attributable to the cost center.” Reg. S-X Rule 4-10(c)(6) requires that (6)(i) supersede the conveyance rules of Oi5.138 including the VPP rules of Oi5.138(a). In addition to industry practice, reasons for not crediting the full cost pool might be:

- Oi5.138(a) on VPP accounting already serves to defer gain or loss and
- Oi5.138(a) eliminates VPP reserves without reduction of the full cost ceiling whereby application of Rule 4-10(c)(6)(i) would more significantly alter the relationship between capitalized costs and proved reserves in the case of a VPP than for the sale of similar mineral interests that are not VPPs.

ACQUISITION OF SHORT-LIFE PROVED PROPERTY, SUCH AS A VPP OR TERM NET PROFITS INTEREST

Reg. S-X Rule 4-10(c)(6)(ii) calls for "significant purchases of production payments or properties with lives substantially shorter than the composite productive life of the cost center [to] be accounted for separately." An acquired VPP, a term net profits interest, a term overriding royalty interest, or any working interest in rapidly depleting property may have to be amortized separately from other proved property located in the same country. Acquisition of a VPP, per se, does not require the VPP to be amortized separately. The VPP must be significant and have a life substantially shorter than the composite productive life of the cost center.

The terms *significant* and *substantially shorter* are not clearly defined. Separate amortization of a large, short-life property may, or may not, have a significant effect on amortization. To illustrate, consider the following example:

	Old Properties	New VPP	Combined
Amortization base, net	$10,000,000	$4,000,000	$14,000,000
Next year's production (boe)	1,000,000	1,000,000	2,000,000
Beginning reserves (boe)	10,000,000	2,000,000	12,000,000
Next year's amortization	$1,000,000	$2,000,000	$2,333,333
Amortization rate	$1.00/bbl.	$2.00/bbl.	$1.17/bbl.

If the cost of the VPP in this example is amortized separately, the total amortization is $3,000,000, whereas if the old properties and the VPP are combined, the amortization would total only $2,333,333 for a difference of $666,667. Yet if the new, short-life VPP's beginning reserves were 4,000,000 boe (for amortization rate of $1.00/bbl.), then next year's total amortization would be $2,000,000 (i.e., $1.00/bbl.) whether or not the new property is amortized separately.

TAX ACCOUNTING

GENERAL TAX TREATMENT OF PRODUCTION PAYMENTS

Since 1969 all types of production payments, with two rare exceptions, have been treated as borrowings or loans for federal income tax purposes. Carved-out production payments have generally been treated as borrowings by the grantor while retained production payments have been treated as notes receivable in amounts equal to their fair values.

One of the two exceptions arises when a production payment is retained in the initial leasing by the mineral rights owner. In this case the lessee records the amounts paid under the production payment as a capitalized installment bonus. Hence, the knowledgeable lessee will avoid taking leases calling for the lessor to retain a production payment.

The second rare exception arises when a production payment is carved out and sold, with the proceeds pledged for use in exploring or developing the properties from which the payment is carved. This payment, too, is deemed to be an economic interest held by the provider of the proceeds. The assignor does not recognize income from the proceeds received on the assignment but must reduce exploration and development costs by the amount received.

GENERAL TAX TREATMENT OF NET PROFITS INTERESTS

For federal income tax purposes, an NPI usually is treated much like an ORRI. Assume X owns the working interest and Y owns a 20 percent NPI. Total gross revenues to X and Y were $200,000. Net profits were $110,000. Y receives $22,000, equivalent to 11 percent of the $200,000. Therefore, of 10,000 barrels produced in generating the $200,000, an 11 percent portion, or 1,100 barrels, is attributable to Y's NPI.

Chapter Twenty-Three

FARMOUTS, CARRIED INTERESTS, AND UNITIZATIONS

The *pooling of capital* concept has long been a part of accounting theory as well as an essential element in federal taxation of the extractive industries. In the oil and gas industry, it is very common for one entity—through the contribution of money, property, or services—to acquire an interest in a mineral property and assume all or part of the risk and burden of developing and operating the property. One party may contribute a leasehold to the venture, another may provide equipment or services such as drilling, and still another entity may contribute money to be used in developing the property. The members of the venture have agreed that they are contributing to a common pool of capital, and thus each may be viewed as merely making an investment in a venture or adding to the venture's reservoir of capital in return for an ownership interest in the venture as a whole. Many transactions of this type may also be considered as exchanges of productive assets in return for similar productive assets, especially if mineral interests, intangible drilling costs, and equipment are all viewed as being similar. Oi5.135 states that no gain or loss is to be recognized at the time of conveyance in a transaction that represents a pooling of capital or that reflects an exchange of similar productive assets. Some of the most commonly encountered applications of these concepts are examined below. (In the discussion that follows it will be assumed that the successful efforts method is being followed. Although the same rules are generally applicable to full cost companies, special considerations applicable to full cost companies are examined at the end of this chapter.)

FARMOUTS

When the owner of a working interest transfers all or part of the operating rights to another party in exchange for the transferee assuming all or part of the cost of exploring or developing the property, the transaction is referred to as a *farmout.* One type of farmout is essentially a sublease without cash consideration, under which the original lessee assigns the working interest but retains an overriding royalty or a net profits interest in return for the assignee's agreement to perform specified drilling and development activities and to pay all costs thereof.

For example, Our Oil Company (OOC) assigned the working interest in the Nellie Bell lease No. 26710, subject to a retained overriding royalty of one-eighth of total production from the property, to Big Time Company. As consideration, Big Time agreed to drill a well to 5,000 feet or to a specified sand, if shallower. Big Time was to complete the well and install all equipment at no cost to OOC. Big Time spent $340,000 for intangible drilling and development costs and $80,000 for lease and well equipment. The lease cost OOC $75,000 and had a fair value of $400,000 at the time the farmout agreement was entered into.

Oi5.138(b), specifies how this transaction should be accounted for by the two parties:

> An assignment of the operating interest in an unproved property with retention of a nonoperating interest in return for drilling, development, and operation by the assignee is a pooling of assets in a joint undertaking for which the assignor shall not recognize gain or loss. The assignor's cost of the original interest shall become the cost of the interest retained. The assignee shall account for all costs incurred as specified by paragraphs .106 through .132 and shall allocate none of those costs to the mineral interest acquired. If oil or gas is discovered, each party shall report its share of reserves and production (refer to paragraphs .160 through .167).

Since OOC has contributed the leasehold and Big Time has drilled and equipped a well on the property, both have contributed to the pool of capital. Each has benefited, yet no gain or loss is to be recognized by either party. OOC's leasehold cost of $75,000 will become its cost of the overriding royalty retained. The entry by OOC to record the transaction would be as follows:

223 Proved Royalties and Overriding Royalties	75,000	
211 Unproved Leaseholds		75,000

To record farmout of Nellie Bell lease and retention of one-eighth override.

The entry above assumes that no impairment of this property has been recorded on an individual lease basis. If impairment has been recorded on an individual basis, the net book value of the lease would be assigned to the overriding royalty. For example, assuming that individual impairment of $30,000 has been recorded on a lease in the preceding example, the entry to record the farmout is as follows:

223	Proved Royalties and Overriding Royalties	45,000	
219	Allowance for Impairment and Amortization of Unproved Properties	30,000	
	211 Unproved Leaseholds		75,000

To record farmout of Nellie Bell lease and retention of one-eighth override.

Big Time classifies its investment in the property on the basis of the type of expenditures made. No part of the costs incurred by Big Time is allocated to the mineral rights obtained, and no gain or loss is recorded. The ultimate entry made by Big Time to record the above facts are summarized as follows:

231	Intangible Costs of Wells and Development	340,000	
233	Tangible Costs of Wells and Development	80,000	
	301 Vouchers Payable		420,000

To record the costs of drilling and equipping well on Nellie Bell lease under a farmout agreement.

If the well had been dry, the costs incurred, less any net salvage value, would have been charged to Unsuccessful Exploratory Wells by Big Time. OOC would presumably have recorded impairment of the overriding royalty.

FREE WELLS

When the owner of a working interest assigns a fractional share of the interest in return for another operator's drilling and equipping one or more wells without cost to the assignor, a *free well* has resulted. The term *free well* is used because the assignor has retained a portion of the working interest and received an interest in the well and equipment without bearing any part of the cost of drilling or equipping the well, and the assignor will share in the first production from the well. A free well is considered to be a sharing arrangement under the pooling of capital concept, and no gain or loss will be recognized by either party to the transaction.

Oi5.138(c) addresses this issue:

> An assignment of a part of an operating interest in an unproved property in exchange for a "free well" with provision for joint ownership and operation is a pooling of assets in a joint undertaking by the parties. The assignor shall record no cost for the obligatory well; the assignee shall record no cost for the mineral interest acquired. All drilling, development, and operating costs incurred by either party shall be accounted for as provided in paragraphs .106 through .132 of this section. If the conveyance agreement requires the assignee to incur geological or geophysical expenditures instead of, or in addition to, a drilling obligation, those costs shall likewise be accounted for by the assignee as provided in paragraphs .106 through .167 of this section.

For example, OOC owned several unproved leases in the Little River area. In January of the current year, OOC entered into a contract with Freeco under which OOC assigned an undivided one-half of the working interest in the Downy lease to Freeco in return for Freeco's drilling and equipping a well on the property at Freeco's cost. The lease cost OOC $24,000. Freeco spent $125,000 on intangibles and $30,000 on equipment for the property, which was considered proved after the well was completed. Each party will receive one-half of the production revenues, beginning with the first production, and each will bear one-half of the operating expenses and further developmental costs.

Since the transaction comes under the pooling of capital concept, the accounting treatment for both parties would be essentially the same as that used in accounting for farmouts. The entry required by OOC, assuming the group impairment method is used, would be as follows:

221 Proved Leaseholds	24,000	
211 Unproved Leaseholds		24,000
To transfer cost of Downy lease to proved leaseholds.		

For Freeco, the ultimate effects of the transaction are expressed in the following summary journal entry:

231	Intangible Costs of Wells and Development	125,000	
233	Tangible Costs of Wells and Development	30,000	
	101 Cash		155,000

To record costs of a free well drilled for a fractional interest in Downy lease.

Under this procedure, OOC assigns no cost to IDC or equipment, whereas Freeco assigns no cost to the mineral interest. Each party will report only its share of production and proved reserves.

Another type of free well agreement calls for the lessee to retain all of the working interest and to assign to the driller a nonoperating interest in the property in return for the latter's drilling and equipping the free well. Using the data in the preceding example, assume that OOC retained the entire working interest in a lease and assigned to Freeco an overriding royalty of one-fourth of total production from the property in return for Freeco's drilling and equipping the well. This transaction represents a pooling of capital because each party has contributed property, money, or services to a joint venture in return for some type of ownership interest in the venture. Thus, no gain or loss would be recognized by either party.

As the holder of a nonoperating interest, Freeco would have no ownership in either the IDC or equipment. It might seem logical that the entire $155,000 spent by Freeco would be treated as the cost of the overriding royalty. However, since Oi5.138c specifically prohibits classifying a portion of the well costs to an earned mineral interest, it would be more consistent with Oi5 conveyance rules for Freeco to treat the entire $155,000 as well costs.

CARRIED INTERESTS

For many years, carried interests have been a frequently used type of sharing arrangement in the oil and gas industry. There are various ways in which carried interest agreements can be worded, but regardless of form, they have the same economic result. A commonly found contract is the *Manahan* type of agreement illustrated below.

OOC, the *carried party*, owner of the working interest in an unproved lease named A1, assigned its entire interest to Developco, the *carrying* *party*, which agreed to pay all the costs of drilling, equipping, and operating the property until Developco has recouped all of its costs of operating, drilling, and equipping the A1 lease. At the time that all costs have been recovered out of the working interest revenues (referred to as the time of *payout*), Developco will reassign one-half of the working interest to OOC (said to have a 50% *reversionary* interest). After payout, OOC and Developco will share equally all further revenues and production expenses and any additional expenditures for drilling or development.

For example, the lease cost OOC $20,000. Developco spent $100,000 for IDC and $32,000 for equipment placed on the lease. The well was completed and production began on November 1, 2000. Assume for the sake of simplicity that working interest revenues were $30,000 per month (for 1,500 barrels per month) beginning with the first production and that expenses were $8,000 per month. On December 31, 2000, proved reserves attributable to the working interest were 390,000 barrels. Based on these facts, Developco will have $22,000 per month of net revenues ($30,000 of revenues, less $8,000 of expenses) to apply toward recoupment of the drilling and development costs. At the end of 2000, Developco will have received $44,000 (two months at $22,000) and will still be entitled to recover an additional $88,000 ($132,000 - $44,000) out of revenues before OOC begins to share in production.

The accounting treatment specified by Oi5.138(d) for carried interests can be summarized as follows:

1. No gain or loss is recognized by either party at the time of conveyance.
2. The expenditures or contributions of each party are accounted for in the usual manner by the party making the expenditure or contribution.
3. All revenues and cash expenses are deemed to belong or apply only to the carrying party until payout; thus, no entries, except the entry to transfer the property's cost to Proved Properties, are necessary by the carried party until that time.

Since neither party records gain or loss on the conveyance transaction, OOC transfers the leasehold cost of $20,000 (or net book value, if impairment has been recorded on an individual lease basis) to Proved Leaseholds when the property becomes proved.

221	Proved Leaseholds	20,000	
	211 Unproved Leaseholds		20,000

To record proving of the A1 lease carried by Developco.

Since Developco is deemed to own the full working interest until payout, its costs of drilling and equipping the well are classified in the usual manner, ultimately resulting in the following journal entry:

231	Intangible Costs of Wells and Development	100,000	
233	Tangible Costs of Wells and Development	32,000	
	101 Cash		132,000

To record drilling and equipment costs on the A1 lease.

Developco is entitled to recover the expenses of operating the property and to retain all the additional net proceeds to apply against the costs incurred for drilling and developing the property until Developco has recovered the entire amount spent. However, if cash proceeds are inadequate to pay expenses and recoup Developco's costs, OOC has no liability to reimburse the carrying party for any part of the unrecovered amount. Based on the facts previously given, Developco will have $22,000 per month of net revenues ($30,000 of revenues less $8,000 of expenses), which is a net of $14.67 for each working interest barrel ($22,000/1,500 barrels), to apply toward recoupment of the drilling and equipment costs. Thus, in November and December of 2000, Developco will include all of the revenues and expenses in its income statement as summarized (for the two months) in general journal form:

101	Cash	60,000	
	601 Crude Oil Revenues		60,000

To record production revenues from the A1 lease.

710	Lease Operating Expenses	16,000	
	101 Cash		16,000

To record production expenses on the A1 lease.

Since all working interest production during payout is deemed to belong to the carrying party, the carrying party's reserve disclosures will include all working interest production expected until payout, plus the carrying party's share of reserves at payout. The reserve quantity to be reported by the carried party prior to payout (and to be used in computing DD&A after payout) will be the carried party's share of reserves at payout.

On December 31, 2000, the proved reserves to be attributed to each party in the above example are computed as follows:

	Barrels
December 31, 2000, total working interest share of proved reserves	390,000
Less barrels expected to be produced from December 31 to date of payout attributed to the carrying party ($88,000 divided by $14.67 per barrel)	(6,000)
Expected reserves at date of payout	384,000
Reserves attributable to carrying party (Developco):	
Barrels to be produced until payout	6,000
One-half of reserves at payout	192,000
Total to carrying party	198,000
Reserves attributable to carried party (OOC):	
One-half of reserves at payout	192,000

OOC has no revenues from production during 2000 and will therefore record no DD&A for the year.

Developco is deemed to have no leasehold costs. However, IDC and equipment amortization will be recorded by Developco in 2000 and computed as follows assuming net DR&A costs are zero:

		IDC	Equipment
3,000/(3,000 + 198,000) x $100,000	=	$1,493	
3,000/(3,000 + 198,000) x $ 32,000	=		$478

Once payout has been reached, each party will report its share of revenues, lifting costs, and additional drilling and development costs in the usual way. Continuing the preceding illustration, assume the following data for 2001 for the lease for which development was carried by Developco for OOC.

- Production and sales (working interest share):

January through November 2001	1,500 bbls per month
December 2001	2,250 bbls

- Sales price per barrel for 2001 — $20 per bbl

- Lifting costs:

January through November 2001	$ 8,000 per month
December 2001	$12,000

- Additional costs on well completed in November 2001:

IDC	$120,000
Tangible Equipment	30,000

- Proved developed reserves, as of December 31, 2001, of 562,500 bbls for 100 percent working interest

- No proved undeveloped reserves

Computations of revenues and expense items to be reported by each party in accordance with Oi5 conveyance rules are given below:

Revenues:

	Barrels	Price	Revenue
Developco:			
Jan 1 through payout, Apr 30	6,000	$20	$120,000
May 1 through Nov 30	5,250	20	105,000
December	1,125	20	22,500
Total	12,375		$247,500
OOC:			
Jan 1 through Apr 30	0	$ 0	$ 0
May 1 through Nov 30	5,250	20	105,000
December	1,125	20	22,500
Total	6,375		$127,500

Production Expenses:

Developco:

Jan 1 through Apr 30	\$8,000/mo x 4 mos	=	\$32,000
May 1 through Nov 30	0.50 x \$8,000/mo x 7 mos	=	28,000
December	0.50 x \$12,000	=	6,000
Total			\$66,000

OOC:

Jan 1 through Apr 30			\$ 0
May 1 through Nov 30	0.50 x \$8,000/mo x 7 mos	=	28,000
December	0.50 x \$12,000	=	6,000
Total			\$34,000

Amortization of mineral interest cost:

Developco: \$0

OOC: $$\frac{6{,}375 \text{ bbls}}{6{,}375 \text{ bbls} + .50(562{,}500 \text{ bbls})} \times \$20{,}000 = \$443$$

IDC and equipment amortization (assuming net DR&A costs are zero):

Developco (assuming an annual computation):

	IDC
12,375/(12,375 + .50 x 562,500) x (\$100,000 + .50 x \$120,000 - \$1,493) =	\$6,680

	Equip.
12,375/(12,375 + .50 x 562,500) x (\$32,000 + .50 x \$30,000 - \$478) =	\$1,961

OOC:

	IDC	Equip.
6,375/(6,375 + .50 x 562,500) x .50 x \$120,000 =	\$1,330	
6,375/(6,375 + .50 x 562,500) x .50 x \$30,000 =		\$332

The information above is ultimately reflected in the accounts of the two companies for the year 2001, as shown in the following summary journal entries:

	Developco		OOC	
231 Intangible Costs . . .	60,000		60,000	
233 Tangible Costs . . .	15,000		15,000	
101 Cash		75,000		75,000
To record additional development costs on the A1 lease.				
101 Cash	247,500		127,500	
601 Crude Oil Revenues		247,500		127,500
To summarize 2001 production revenues from the A1 lease.				

	Developco		OOC	
710 Lease Operating Expense	66,000		34,000	
101 Cash		66,000		34,000
To record 2001 production expenses on the A1 lease.				
732 Amort. of Intang. Costs of Wells	6,680		1,330	
232 Accum. Amort. of Intangible Costs of Wells and Develop.		6,680		1,330
734 Amort. of Tang. Costs of Wells	1,961		332	
234 Accum. Amort. of Tangible Costs of Wells and Develop.		1,961		332
To record 2001 amortization on wells and facilities on the A1 lease.				
726 Amortization of Proved Property Acquisition Costs			443	
226 Accumulated Amortization of Proved Property Acquisition Costs				443
To record 2001 depletion on the A1 lease.				

As previously noted, the exact form of the contract creating a carried interest may vary. For example, a nonconsent clause in a joint venture operating agreement may give rise to a carried working interest. To illustrate, OOC proposes that an additional well be drilled to fully exploit a reservoir. Developco disagrees and elects to not participate. Developco has *gone nonconsent* on this well, and the operating agreement will typically entitle OOC to drill and produce the well, receive all working interest revenues, and pay all operating costs for the well until OOC recovers some specified multiple (e.g., 300 percent) of all costs of drilling and equipping the well. When the multiple is achieved, payout occurs, after which Developco participates in this particular well's revenues and costs based on Developco's working interest as if it had not gone nonconsent. See the nonconsent provision on App. 9-17 to 9-20.

For additional guidance, refer to COPAS Bulletin No. 9, *Accounting for Farmouts/Farmins*, *Net Profit Interests and Carried Interests*.

PROMOTED VS. PROMOTING

In most joint ventures, the venturers share both costs and revenues in proportion to their ownership interests in the properties. For example, assume that joint venture partners A and B each have a 50 percent working interest and a 45 percent net revenue interest in a venture (the Lessor has a ten percent net revenue interest in the form of a royalty interest). Since the parties share costs and revenues in the same proportions, this type of joint venture is sometimes referred to as a *straight-up* arrangement. However, in some cases costs and net revenues are not shared in the same ratios. For example, a joint venture agreement may call for joint venturers X and Y to each receive 45 percent of the net revenues (the other ten percent going to the royalty holder), but for X to bear 40 percent of costs and Y to bear 60 percent of costs. In this situation X is said to be the *promoter* or *promoting* party and Y the *promoted* party. Such an arrangement might occur if X originally owned 100 percent of the working interest in an attractive property and agreed to let Y have half of the working interest's 90 percent share of revenues in return for Y paying 60 percent of costs.

UNCLE SAM: THE PROMOTING, SILENT PARTNER

It might be considered that U.S. income tax laws make Uncle Sam a silent partner in every U.S. oil and gas venture. Years ago, before the alternative minimum tax and before limitations in percentage depletion, Uncle Sam was a *promoted* silent partner in that the net tax benefits reduced the effective income tax rate below the stated rate. For example, if the stated tax rate was 35 percent on taxable income, the immediate deduction of IDC meant that Uncle Sam *paid* for 35 percent of IDC when it was incurred. Old tax laws allowed equipment costs to be quickly deducted and allowed for an investment tax credit. However, the percentage depletion tax deduction sheltered some cash flow from taxation whereby Uncle Sam received less than 35 percent of future cash flow from production. Thus, in such cases, Uncle Sam paid proportionately more for costs than it shared in revenues and was a promoted silent partner.

Today, Uncle Sam pays for 35 percent of costs but not all of it immediately. The investment tax credit is gone, and percentage depletion has been restricted. Today, Uncle Sam's effective tax rate often exceeds the 35 percent stated corporate tax rate. Hence, Uncle Sam may now said to be a *promoting* silent partner in many E&P ventures. As a promoting partner, Uncle Sam's internal rate of return on the venture would exceed the oil company's internal rate of return.

UNITIZATIONS

One of the most important forms of sharing arrangements is the *unitization*, under which all the owners of operating and nonoperating interests pool their property interests in a producing area (normally a field) to form a single operating unit, and in return receive undivided interests (commonly called *participation factors*) in the total unit (either operating or non-operating interests, as held in the properties contributed).

Unitizations are usually undertaken to achieve the most efficient and economical exploitation of the reserves in an area. Unitizations may be voluntary or required by federal or state regulatory bodies. Unitizations are common in fields with primary production and even more common for reservoir-wide enhanced recovery operations (explained in Chapter Thirty-One).

Unitizations are popular offshore where costs are very high and reserves may be uneconomic on an individual basis, but the joint development of an area makes a unit economically feasible. Units typically involve more than one lease and have diverse ownerships of various mineral interests and reservoirs that cross lease boundaries.

The participation factor (the share in the unit that each participating owner is to receive) is based on acreage, reserves, or other factors with respect to each lease to be placed in the unit.[77] The percentage may be subject to revision within a specified subsequent period as additional information about the reserves becomes available. The accounting problems resulting from subsequent adjustments are discussed later in this

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[77]A participant's fractional interest (or *participation factor*) might be based on any number of reasonable factors—acreage, estimated reservoir thickness under a given acreage, estimated reserves under a given acreage, number of producing wells on the acreage, and even prior production history for the acreage.

chapter. However, participation factors do not usually give weight to the stage of development of properties. The leases are often in different phases of development, with some leases being fully drilled and equipped, others being partially developed, and some completely undeveloped.

EQUALIZATIONS

Unit participants with undeveloped leases in the unit are normally required to pay cash to participants with fully or partially developed leases in the unit in order to equalize the capital contributions of wells and equipment.

For example, the 600 acre Ajax lease, 100 percent owned by Company A, is to be unitized with the adjoining 400 acre Brown lease, 100 percent owned by Company B. Unit participation factors are to be based on acreage whereby Company A has a 60 percent participation factor and Company B has a 40 percent participation factor for both unit costs and unit revenues. Company A pays the Ajax lease royalty based on A's share of revenues. Company B pays the Brown lease royalty based on B's share of revenues. Prior to unitization, Company A spent $700,000 on two wells, and Company B spent $300,000 on one well. Terms of the unitization agreement may require that the $1,000,000 of prior well costs be reallocated so that the sharing of prior well costs equals the sharing of post-unitization costs and revenues. To do so, Company B pays $100,000 to Company A at the time of unitization so that A's adjusted well cost is $600,000, or 60 percent of total well costs, and B's adjusted well cost is $400,000. Such adjustments are called *equalizations*.

Equalizing Pre-Unitization Costs

In new fields in which development has not been completed, it is common for the equalization agreement to be based on expenditures for exploration and drilling that have occurred prior to the date of unitization. Where pre-unitization costs are to be equalized, the process involves four steps:

(1) Identifying the pre-unit contributions that are to be allowed in computing equalization,
(2) Accumulating or collecting the contributions of each pre-unit working interest owner,

(3) Calculating the obligation of each working interest owner for pre-unit costs, and
(4) Determining settlement for the underspent and overspent amounts.

Generally the expenditures that have been made for wells and facilities that directly benefit the unit are accepted for equalization, whereas those costs that relate to other wells and facilities that do not benefit the unit are not equalized. The costs to be equalized almost always include direct costs such as labor, employee benefits, taxes, construction charges, costs of special studies, and other expenditures that can be specifically identified with individual wells and equipment. In addition, geological and geophysical costs, permits, and environmental study costs may be considered as direct charges.

Overhead not directly related to individual wells and facilities may also be equalized. These costs include such items as offsite labor, administrative charges, and the cost of operating district or regional offices. The parties frequently limit overhead to some percentage of direct costs or to some specified fixed annual fee, or the computation may be based on time spent by personnel.

In addition to direct costs and overhead, the unitization agreement may permit an equalization of *risk* charges or imputed risk charges. For example, insurance costs incurred in transporting equipment and facilities or the imputed costs of insurance to cover facilities prior to unitization may be considered. Finally, equalization agreements may provide for an inflation factor to reimburse the parties for changes in purchasing power between the time of the original investment and the time of ultimate recovery from other owners.

Cash Equalization

The unitization process is a pooling of capital to achieve a common benefit for all parties, and thus normally no gain or loss will be recognized by any party to the unitization. A party making a cash equalization payment will increase the recorded investment in wells and related equipment and facilities. On the other hand, a participant who receives a cash equalization payment will reduce the recorded investment in the wells and related equipment. Oi5.138(f) contains the following accounting guidelines for unitizations:

> Because the properties may be in different states of development at the time of unitization, some participants may pay cash and others may receive cash to equalize contributions of wells and related equipment and facilities with the ownership interests in reserves. In those circumstances, cash paid by a participant shall be recorded as an additional investment in wells and related equipment and facilities, and cash received by a participant shall be recorded as a recovery of costs. The cost of the assets contributed plus or minus cash paid or received is the cost of the participant's undivided interest in the assets of the unit. Each participant shall include its interest in reporting reserve estimates and production data.

A relatively simple example will suffice to indicate the financial accounting treatment required by Oi5.138(f) at the time of unit formation. Three E&P companies are involved in a unitization of their respective properties, which have already been developed. Based upon various factors such as acre-feet of sand contributed, it is decided that each party will have a one-third interest in the unit. The unitization agreement provides specifically:

> Inasmuch as the value of wells drilled and of wells and other operating equipment on the separately owned tracts is not in proportion to the participating interest of the owners of such tracts, and such values have not entered into the determination of the participation percentages, a separate exchange of interest in wells and well equipment, lease equipment, and other operating equipment will be made between the parties hereto.

In order to give each party proper credit for IDC and equipment, a cash equalization will have to be made among the parties, calculated in the table below. The undepreciated balance of well costs on each party's books is shown in Column (2) of the schedule below. Column (3) represents the agreed-on value of the well costs contributed by each party, based on current costs to drill the usable wells contributed by each party, and Column (4) reflects the share of the agreed-on value of well costs belonging to each party after the unitization. The cash to be contributed or received by each party to *equalize* the value of well costs received and contributed is shown in Column (5). (In newly developed fields the *agreed-on value* is usually deemed to be equal to *allowable* costs incurred by each party for exploration and development prior to the unitization.)

Equalization for IDC:

(1) Party	(2) Unamortized Balance	(3) Value Contributed	(4) Value Received	(5) Cash Equalization
A	$300,000	$ 550,000	$ 400,000	$150,000
B	260,000	375,000	400,000	(25,000)
C	320,000	275,000	400,000	(125,000)
Total		$1,200,000	$1,200,000	$ 0

Equalization for equipment:

(1) Party	(2) Unamortized Balance	(3) Value Contributed	(4) Value Received	(5) Cash Equalization
A	$20,000	$ 50,000	$ 60,000	$(10,000)
B	70,000	65,000	60,000	5,000
C	65,000	65,000	60,000	5,000
Total		$180,000	$180,000	$ 0

The accounting entries to reflect the unitization process in the accounts of the three companies are summarized below.

Mineral Rights Equalization. No monetary entries are necessary to record the exchanges of mineral rights in the property transferred to the unit for a share of minerals in the unit. Each party will treat the book value of the property contributed by that party as the investment in the mineral interest in the unit. (As previously pointed out, most unitization agreements, especially when some of the properties have not been fully developed, call for one or more subsequent evaluations and readjustment of participation factors, a topic discussed later in this chapter.)

IDC Equalization. Party A received $150,000 cash as equalization for IDC. In accordance with Oi5.138(f), the cash received is treated merely as a reduction of investment:

101 Cash	150,000	
231 Intangible Costs of Wells and Development		150,000

To record receipt of cash on IDC equalization.

Since the unamortized balance of A's IDC contribution is greater than the amount of cash received, the equalization payment merely reduces the investment.

Both B and C must make cash payments to equalize the IDC. Under Oi5.138(f), the payments are capitalized as additional investment in IDC.

Equipment Equalization. Both B and C receive cash in equalization of equipment contributions. In each case the amount of cash received is less than the book value of the equipment contributed; therefore, the full amount received will be credited to Account 233, Tangible Costs of Wells and Development.

Equalization in Excess of Cost. Due to the valuation process, in which valuations are made and current pricing is taken into account, the possibility of receiving equalization credit in excess of cost does exist. Referring to Oi5.138(f), a unitization is a pooling of assets for the purpose of developing and producing oil and gas from a particular property or group of properties. As such, no gain or loss is recognized in equalizations. After equalization, the carrying value of a well may be negative for book purposes, but individual asset-carrying values within a proven property asset pool are generally not important under either successful efforts or full cost accounting methods.

Disproportionate Spending Equalization

The parties may wish to avoid cash equalization, preferring instead to equalize contributions other than mineral interests by adjusting the amount of future expenditures to be paid by each party to compensate for disproportionate contributions. This technique is especially common in new fields in which there has been little drilling activity up to the time of unitization.

To illustrate a cost-equalization program involving disproportionate spending, the following schedule shows the working interest ownership of each party, the pre-unit costs, the costs to be borne by each party, and the over/underspent position of each:

Table 1

Company	Working Interest Ownership	Pre-unitization Costs Incurred	Proportionate Share	Over or (Under) Spent
Acorn	50%	$1,000,000	$ 750,000	$250,000
Barn	35	300,000	525,000	(225,000)
Check	15	200,000	225,000	(25,000)
		$1,500,000	$1,500,000	$ 0

Since the actual expenditures incurred by Acorn Company prior to unitization exceed its proportionate share of total costs of $1,500,000, Acorn will pay no part of costs after unitization until the other two companies have overspent their shares by the same amount that Acorn overspent before unitization. The subsequent overspending by the two parties which were underspent prior to unitization will be shared in the ratio of the proportionate interest of the shortfall. Thus, in the example above, Barn Company will absorb 90 percent (225/250), and Check Company will absorb 10 percent (25/250) of the first $250,000 of future expenditures to bring the parties back in balance to their proportionate working interests.

A reasonable interpretation of the provisions of Oi5.138(f) relating to sharing arrangements suggests that each party account for its actual expenditures in the normal manner.

Equalization Resulting from Redetermination of Interests

As pointed out previously, unitization agreements, especially those involving newly discovered fields, frequently contain provisions requiring that the ownership be redetermined and adjusted at dates subsequent to the date of unitization. The adjustment is based on changes in estimates of recoverable reserves, resulting from improved technical knowledge of the reservoir as the field is developed and oil and gas are produced. Between the dates of the unitization and the subsequent readjustment, production revenues as well as operating expenses and development costs are allocated on the basis of the percentages of ownership interest computed as of the date of unitization. When the redetermination is made, it may become effective retroactive to the date of the formation of the unit. In other cases it is effective at a later date, such as when a discovery changes the size and extent of the proved portion(s) of reserves. As a result, it will be necessary to make an equalization computation at the date of redetermination to equalize production proceeds and costs incurred during the period prior to redetermination. It is customary for the equalization of production to be effected through undertakes and overtakes of subsequent production rather than through a cash settlement. The equalization of post-unitization costs incurred is normally handled through disproportionate spending equalization, as previously described.

For example, assume that a unitization agreement became effective on January 1, 2000, at which time equalization for prior expenditures was made through a cash settlement. The initial agreed-upon ownerships were

30 percent to Company X, 50 percent to Company Y, and 20 percent to Company Z. The agreement called for a redetermination of ownership interests as of January 1, 2003, based on revised estimates of the oil and gas reserves contributed to the unit by the three parties. During the three-year period prior to redetermination, production totaled ten million barrels at an average price of $15 per barrel. Development expenditures of $30 million for drilling costs and $10 million for equipment and facilities were incurred. Operating expenses were $10 million. All revenues and costs were shared in the original agreed-upon ratio of 30 percent, 50 percent, and 20 percent.

On January 1, 2003, the redetermination is made and the working interests are readjusted as follows: X, 27 percent; Y, 55 percent; and Z, 18 percent. Equalization for the over/undertake of production prior to this redetermination is to be accomplished by offsetting over/undertakes of production over the two-year period following redetermination. The equalization of over-expenditures and under-expenditures for development costs and operating expenses is to be accomplished through an adjustment of costs incurred after the redetermination of interests.

Thus, during each month of the two-year period following redetermination, Company Y would receive 20,833 barrels in excess of its normal share of production, and the shares of Company X and Company Z would be reduced by 12,500 barrels and 8,333 barrels per month, respectively, in order to correct the misallocation of prior production.

Table 2

(in barrels)

Company	Initial Allocation of Production	Redetermined Allocation of Production	Over or (Under) Produced	Monthly Equalization Over 24 Months
X	3,000,000	2,700,000	300,000	(12,500)
Y	5,000,000	5,500,000	(500,000)	20,833
Z	2,000,000	1,800,000	200,000	(8,333)

Assuming that production in the first month following redetermination was 300,000 barrels, it would be allocated as follows:

Table 3

Company	Percent of Working Interest	Normal Allocation of Production (bbl)	Equalization Adjustment (bbl)	Total Share of Production (bbl)
X	27	81,000	(12,500)	68,500
Y	55	165,000	20,833	185,833
Z	18	54,000	(8,333)	45,667
Total	100	300,000	0	300,000

The tables indicate equalization of production quantities but not revenues per se. In order to equalize revenues, the actual monthly price of oil (or gas) would have to be compared to the average price received prior to redetermination, which was $15 per barrel in this example. Any variance in price would also require consideration in the equalization redetermination. This calculation could be made monthly, but due to timing and information flow, the adjustment would normally be in arrears.

Table 4

Company	Monthly Equalization (bbl)	Pre-equalization Price	January 2000 Price	January Revenue Equalization
X	(12,500)	$15/bbl	$25/bbl	$125,000
Y	20,833	15/bbl	25/bbl	(208,330)
Z	(8,333)	15/bbl	25/bbl	83,330

Company X gave up 12,500 barrels in January worth $25 per barrel to compensate for taking in prior months 12,500 barrels worth $15 per barrel, so the revenue equalization gives Company X $125,000 for the $10/bbl. differential for 12,500 barrels.

The equalization of development costs and operating expenses would be accomplished through disproportionate spending equalization in the manner illustrated previously.

Under the general rules established for poolings of capital in Oi5.135 and Oi5.138, no accounting entries would be necessary at the time of post-unitization redetermination of interests. It would be appropriate for each owner to report revenues actually received, reflecting any increase or decrease due to the adjustment, and for each party to account in the usual way for all costs incurred. Reserve disclosures would reflect the readjusted amounts, and future depreciation, depletion, and amortization calculations would be based on the revised estimates.

UNITIZATION ON FEDERAL LANDS

Unitization on federal lands has unusual features that complicate unitization accounting. Federal unitization is a two-step process. First, lessees of federal mineral rights in a large prospective area of perhaps several thousand acres (the unit area) sign an exploratory unit agreement and a unit operating agreement to "adequately and timely explore and develop the committed leases within the unit area without regard to the interior boundaries of the leases."[78] Second, pursuant to the unit agreements, as proved areas within the unit area become known, the leaseholders within a proved area (called *participating area* or *PA*) are required to form a joint venture to develop and operate the participating area and share in costs and revenues. A PA expands as new wells expand the proved area, and the PA may contract as dry holes and uneconomic wells are drilled and define the productive area. Two or more PAs may combine into one large PA as new wells demonstrate the continuity of the underlying reservoir. A large unit area may have more than one PA when the unit area is ultimately developed.

Often a PA interest is determined by relative acreage of the lease areas within the PA. A company's 100 percent working interest in a 320-acre lease with one well may entitle the company to a 50 percent working interest in a two-well or three-well 640-acre PA encompassing the lease. As the PA expands to 3,200 acres and, say, 15 wells, the company's PA interest may fall to ten percent whereby the company pays ten percent of all 15 wells' costs and receives ten percent of the PA revenues after royalties, assuming uniform royalty rates. Any PA formation, expansion, or contraction is approved by the U.S. Department of the Interior and is generally effective with (and retroactive to) the completion date of the well that justified the PA change. Hence, a company's working interest in a PA

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[78]See the Unitization section of the United States Department of the Interior Bureau of Land Management's Handbook for a discussion of this topic.

will vary as the PA expands or contracts. Accounting for a PA interest is complex and subject to retroactive adjustment.

A company can elect to *go nonconsent* and not participate in future wells within the PA or the unit, subject to a nonconsent penalty.[79] However, accounting for nonconsent interests is made difficult and has been the subject of litigation due to internally inconsistent language in at least three versions of a standard unit operating agreement form used from 1954 through the early 1990s. A discussion of this issue is beyond the scope of this book, but the issue is indicative of the complexity of and difficulty in accounting for PA interests.

Prudhoe Bay Example of Redetermination and Participating Areas

An example of post-unitization redetermination is described in the excerpt below from the forepart of the 1999 Form 10-K of BP Prudhoe Bay Royalty Trust. The trust has a net profits interest akin to a 16.4246 percent ORRI (royalty interest) in British Petroleum's first 90,000 barrels per day of production from the Prudhoe Bay Unit.[80]

> **THE PRUDHOE BAY UNIT**
>
> **General**
>
> The Prudhoe Bay field (the *Field*) is located on the North Slope of Alaska, 250 miles north of the Arctic Circle and 650 miles north of Anchorage. The Field extends approximately 12 miles by 27 miles and contains nearly 150,000 productive acres. The Field, which was discovered in 1968 by BP [the Company] and others, has been in production since 1977. The Field is the largest producing oil field in North America. As of December 31, 1998, approximately 9.7 billion STB (Stock Tank Barrels[81]) of oil and condensate had been produced from the Field. Field development is well advanced with approximately $17.5 billion gross capital spent and a total of about 1,885 wells drilled. Other large fields located in the same

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[79] The concept of nonconsent and nonconsent penalty is addressed briefly in Chapter Ten.

[80] The trust share in revenues is reduced for certain *chargeable cost*s of several dollars per barrel.

[81] Stock Tank Barrel refers to a marketable barrel of crude oil at 60° F and at atmospheric pressure whereby solution gas has bubbled out of the crude oil or solution gas and water have been removed from the produced crude oil.

area include the Kuparuk, Endicott, and Lisburne fields. Production from those fields is not included in the Royalty Interest.

Since several oil companies hold acreage within the Field, the Prudhoe Bay Unit was established to optimize Field development. The Prudhoe Bay Unit Operating Agreement specifies the allocation of production and costs to Prudhoe Bay Unit owners. The Company and a subsidiary of the Atlantic Richfield Company (ARCO) are the two Field operators. Other Field owners include affiliates of Exxon Corporation (Exxon), Mobil Corporation (Mobil), Phillips Petroleum Company (Phillips) and Chevron Corporation (Chevron).

Prudhoe Bay Unit Operation and Ownership

. . . The Prudhoe Bay Unit Operating Agreement specifies the allocation of production and costs to the working interest owners. The Prudhoe Bay Unit Operating Agreement also defines operator responsibilities and voting requirements and is unusual in its establishment of separate participating areas for the gas cap and oil rim. . . .

The ownership of the Prudhoe Bay Unit by participating area as of December 31, 1998 is summarized in the following table:

	Oil Rim	Gas Cap
BP	51.22%(a)	13.85%
Arco	21.87	42.56
Exxon	21.87	42.56
Mobil/Phillips/Chevron (MPC)	4.44	1.03
Others	0.60	0.00
Total	100.00%	100.00%

(a) The Trust's share in oil production is computed based on BP's ownership interest of 50.68% as of February 28, 1989.

CREATION OF JOINT VENTURES

Prior chapters have noted that E&P joint ventures are common in the U.S. Chapter Ten addressed joint venture operations, the billing of joint venture costs, and the day-to-day accounting for joint interests. Oi5.138(e) describes joint ventures and indicates how the formation of a joint venture is to be accounted for:

> A part of an operating interest owned may be exchanged for part of an operating interest owned by another party. The purpose of such an arrangement, commonly called a joint venture in the oil and gas industry, often is to avoid duplication of facilities, diversify risks, and achieve operating efficiencies. Such reciprocal conveyances represent exchanges of similar productive assets and no gain or loss shall be recognized by either party at the time of transaction. In some joint ventures, which may or may not involve an exchange of interests, the parties may share different elements of costs in different portions. In such an arrangement a party may acquire an interest in a property or in wells and related equipment that is disproportionate to the share of costs borne by it. As in the case of a carried interest or a free well, each party shall account for its own cost under the provisions of this section. No gain shall be recognized for the acquisition of an interest in joint assets, the cost of which may have been paid in whole or in part by another party.

Two of the major points in this paragraph warrant illustration. Assume that two operators own contiguous unproved properties. For the sake of efficiency they agree to form a joint venture, with OOC to own a two-thirds interest in the venture and South Company to own a one-third interest. They *cross-assign* interests, OOC assigning to South Company a one-third undivided interest in a property (which had a book value of $120,000 and was being impaired individually). South Company assigns a two-thirds interest in each of three leases (which had a cost of $260,000 and are part of a group subject to a group impairment test). Neither party recognizes a gain or loss on the exchange. OOC should remove one-third of the cost of the lease in which it gave up an interest and one-third of the allowance for impairment of the lease. The net book value ($40,000) of the one-third interest will be assigned to the two-thirds interest in the three leases acquired from South Company. The allocation of the $40,000 to individual leases (in which interests were acquired) should be based on relative market values of the interests. Similar entries based on the appropriate amounts would be recorded by South Company.

A second point involves *disproportionate sharing arrangements*. Suppose, for example, that OOC, which uses successful efforts accounting, owns a lease which cost $30,000 and on which no impairment has been recorded. OOC retains one-fourth of the working interest and assigns three equal interests of one-third of three-fourths of the working interest to other parties, which are to bear the entire cost of drilling the first well. If the first well is to be completed, all parties, including OOC, are to pay for a proportionate share of completing the well. This type of arrangement is the *third for a quarter* deal common years ago when oil prices were escalating rapidly. The drilling cost on this well amounted to $600,000, which was paid in equal shares by the other three parties.

OOC will retain $30,000 as its leasehold cost, will have no intangible cost, and will record its share of equipment costs when the costs are incurred. Each of the assignees will account for the $200,000 contributed to the venture as IDC, and each will properly account for its cost of equipment subsequently acquired. The assignees will not treat any part of their contributions as leasehold cost.

FULL COST ACCOUNTING

Reg. S-X Rule 4-10(c)(6) stipulates that in general the conveyance rules found in Oi5.133 shall apply not only to successful efforts companies but also to companies using full cost. However, Reg. S-X Rule 4-10(c)(6)(iii) adds that under the full cost method, no income shall be recognized from sales of unproved properties or participation in various forms of drilling arrangements involving oil and gas producing activities. Problems relating to the formation and operations of partnerships are discussed in Chapter Twenty-Four.

TAX ACCOUNTING

Tax accounting for farmouts, carried interests, and unitizations depends on many circumstances and on specific terms in the underlying agreements. Some accounting issues are unsettled; some related court decisions seem to conflict. Below are some of the key accounting matters in this area.

For carrying arrangements, the carrying parties typically pay 100 percent of IDC and equipment, but a portion of such costs may need to be capitalized as depletable leasehold investment. If the carrying parties own 100 percent of the working interest until payout, i.e., when cumulative well revenues equal cumulative well drilling and completion costs plus cumulative well operating cost, then the carrying parties may deduct (in the manner they would normally deduct their noncarried costs), 100 percent of the well costs as IDC and equipment depreciation. Upon payout, any undepreciated equipment costs are reclassified as depletable leasehold costs. Under other conditions (whereby the carrying parties are not entitled to 100 percent recoupment of the well costs), some or all of the carried costs must be capitalized as depletable leasehold costs.

Internal Revenue Code §614(b)(3) provides that the taxpayer's properties in a compulsory unitization are treated as one property upon unitization. This rule applies to certain voluntary unitizations as well. Generally the unitization is viewed as an exchange of the taxpayer's old properties for a new property. This may give rise to taxable gain to the extent of cash received to adjust participants' share of unit costs. It may also give rise to an exchange of depreciable equipment costs for depletable leasehold costs—delaying or eliminating deduction of such costs.

Joint ventures are not generally taxed as corporations nor treated as partnerships. The joint venture owner's net share of the joint venture revenue and expenses determines the owner's taxable income. To avoid corporate status, the oil and gas joint venture agreement typically provides that each joint venture owner has the *option* to take its oil and gas in kind, i.e., take title and possession of crude oil barrels or natural gas mcf rather than take a portion of cash proceeds from the operator or venture selling the oil and gas. The option to take in kind may never be exercised, but the option has been viewed as sufficient to eliminate the *joint profit objective* regarded in tax rules as inherent to a corporation.

The joint venture can avoid being treated as a partnership by simply electing in its initial year not to be treated as a partnership, i.e., elect out of Subchapter K. The election may be evidenced by a provision stating such in the joint venture agreement. Election out of partnership status has various advantages, such as avoiding (1) the filing of partnership tax returns, (2) the maintaining of certain partnership accounting records, and (3) the need for the partnership to elect to deduct IDC as incurred.

Chapter Twenty-Four

ACCOUNTING FOR PARTNERSHIP INTERESTS

Oil and gas operators, both individuals and corporations, may invest as partners in general partnerships or limited partnerships involved in oil and gas exploration and production. When an E&P company invests in a general partnership, it is usually with the intent to enter into a joint operation with one or more other E&P companies, but for some reason, usually related to tax laws or to legal circumstances, the partners do not wish to operate as undivided interest holders, which is the common approach to joint operations. When an E&P company invests in a limited partnership, it is usually as the operating general partner. The limited partnership is used as a vehicle for obtaining financing from individual or institutional investors that are the limited partners.

The accounting problems facing either the general partner or the partnership itself do not differ greatly, whether the venture is a general partnership or a limited partnership. Financial statements must be prepared, tax returns must be filed, and partners must be provided with information to enable them to prepare their own tax returns. Sometimes the accounting problems for limited partnerships are more complex because of special allocations of revenue, expenses, costs to the partners, and reversionary interests. Also, in the case of a limited partnership, certain filings with the Securities and Exchange Commission may be necessary because some limited partnerships are subject to regulation by the SEC.

For both general partnership and limited partnership investments, there are three major areas of concern: (1) reporting at the partnership level, (2) reporting at the partner level for the partnership investment, and (3) accounting for transactions between the partner and the partnership.

GENERAL PARTNERSHIPS

ACCOUNTING AND REPORTING AT THE PARTNERSHIP LEVEL

A partnership is a separate entity. Therefore, the partner who manages the partnership is responsible for maintaining a complete set of records for the partnership, for filing the appropriate tax returns, and for providing both financial accounting and tax information to the other partners. The partnership chooses its own fiscal year and accounting method. Either the full cost method or successful efforts method may be adopted by the partnership that wishes to maintain records on the basis of GAAP. The partnership may maintain records on a tax basis; this simplifies the preparation of the federal tax return by the partners but will complicate the partners' accounting for their investments in the partnership under GAAP.

Costs of organizing a general partnership are usually quite small and are to be expensed following the guidance of SOP 98-5, *Reporting on the Costs of Start-up Activities.*

REPORTING THE PARTNERSHIP INVESTMENT

In accounting for an investment in a partnership, a partner used either the equity method or the proportionate consolidation method. A forthcoming Statement of Financial Accounting Standards on the subject of consolidation may require full consolidation when the general partner effectively controls a limited partnership and require equity accounting when the general partner has significant influence but not control.

The SEC staff views pro-rata consolidation to be inappropriate for interests in jointly controlled corporate entities, even if there is an agreement which attributes benefits and risks to the owners as if they held undivided interests. The staff views pro-rata consolidation appropriate for interests in partnerships and other noncorporate forms of joint ownership only if such interests are equivalent to holding undivided interests in assets (with severable liability for incurred related indebtedness) as described in SOP 78-9.

EITF Issue 00-01, “Applicability of the Pro Rata Method of Consolidation to Investments in Certain Partnerships and Other Unincorporated Joint Ventures,” acknowledges that pro-rata consolidation of an undivided oil and gas interest is appropriate, but asks whether pro-rata consolidation is appropriate for oil and gas partnerships or other unincorporated joint ventures. The EITF had expressed no conclusion at the time this chapter was being prepared.

Under the equity method, a partner's initial investment is recorded in an account with a title such as *Investment in XYZ Partnership*. At the end of the fiscal period, the partner's share of income (or loss) is recorded as an increase (or decrease) in the investment account and appears as a single amount under a heading such as *Income from XYZ Partnership* in the income statement. The balance in the investment account is shown as a single amount on the partner's balance sheet under the heading of *Investments*.

Under the proportionate consolidation method, a partner includes a proportionate share of each partnership asset and liability in the partner's balance sheet and each revenue and expense in the partner's income statement. Although it is possible for the partner to maintain actual accounts reflecting the ownership share in each partnership item, it may be easier in some cases for the partner to use the equity method of accounting for the transactions with the partnership during the fiscal period, and then at the end of the fiscal period eliminate the investment account and substitute the appropriate amounts of the partnership's assets and liabilities. Similarly, the *Share of Income or Loss of the Partnership* account would be eliminated, and the proper share of the individual revenues and expenses would be substituted in the income statement.

Assume that X Corporation uses the successful efforts method of accounting, as does XYZ Partnership, in which X Corporation owns a one-fourth interest. X Corporation invested $750,000 for that interest on January 2, 2000. For 2000, XYZ Partnership has a $1,000,000 loss. XYZ's 25 percent share is $250,000 before $80,000 in related income tax reduction. Figure 24-1 illustrates the equity and proportionate consolidation methods for X Corporation's share of XYZ Partnership's loss.

The necessary data for the proportionate consolidation would be obtained from the financial reports provided by the partnership to the partner at the end of the fiscal period if the partnership and the partner use the same accounting method and have the same fiscal year.

If there are special allocations of revenues or expenses, or if the accounting method used by the partnership is different from that used by the partner, it will be necessary for the partner to reconstruct or reconcile its share of the partnership's accounts. This can be done based on the periodic reports of partnership expenditures and revenues prepared by the managing partner.

Comments on the Equity Method

Under the equity method, neither the share of the investee's reserves nor the share of the investee's oil and gas assets enter into the depreciation, depletion, and amortization calculation of the investor under either the full cost method or the successful efforts methods.

Figure 24-1: Example of Equity Method vs. Proportionate Consolidation

Summarized Trial Balances as of December 31, 2000 (in 000's)

Equity Method:	XYZ Part.	X Corp. Pre-entry	X Corp. Entry	X Corp. Post-entry
Cash	$ 240	$ 500		$ 500
Receivables	200	2,000		2,000
Oil & Gas Properties	2,380	10,000		10,000
Investment in XYZ Partnership		750	($250)	500
Other Assets	180	1,000		1,000
Total Assets	$ 3,000	$14,250	($250)	$ 14,000
Liabilities & Deferred Taxes	$ 1,000	$ 5,000	($80)	$ 4,920
Partners' Capital	2,000			0
Stockholder's Equity		$ 9,250	(170)	9,080
Total Liabilities & Equity	$ 3,000	$14,250	($250)	$ 14,000
Revenue	$1,000	$20,000		$ 20,000
Production Expense	(200)	(6,000)		(6,000)
Exploration Expense	(1,500)	(5,000)		(5,000)
DD&A	(200)	(4,000)		(4,000)
G&A Expense	(100)	(1,400)		(1,400)
25% share of XYZ Loss			($250)	(250)
Income Tax Provision		(1,200)	80	(1,120)
Net Income (Loss)	($1,000)	$ 2,400	($170)	$ 2,230

Proportionate Consolidation Method:	XYZ Part.	X Corp. Pre-entry	X Corp. Entry	X Corp. Post-entry
Cash	$ 240	$ 500	$ 60	$ 560
Receivables	200	2,000	50	2,050
Oil & Gas Properties	2,380	10,000	595	10,595
Investment in XYZ Partnership		750	(750)	-
Other Assets	180	1,000	45	1,045
Total Assets	$ 3,000	$14,250	0	$ 14,250
Liabilities & Deferred Taxes	$ 1,000	$ 5,000	$ 170	$ 5,170
Partners' Capital	2,000		0	0
Stockholder's Equity		9,250	(170)	9,080
Total Liabilities & Equity	$ 3,000	$14,250	0	$ 14,250
Revenue	$ 1,000	$20,000	$ 250	$ 20,250
Production Expense	(200)	(6,000)	(50)	(6,050)
Exploration Expense	(1,500)	(5,000)	(375)	(5,375)
DD&A	(200)	(4,000)	(50)	(4,050)
G&A Expense	(100)	(1,400)	(25)	(1,425)
25% share of XYZ Loss				0
Income Tax Provision		(1,200)	80	(1,120)
Net Income (Loss)	($1,000)	$ 2,400	$ (170)	$ 2,230

* Assumes partnership's properties are in separate cost centers from X's.

When the equity method is used to account for an investment in an oil and gas entity, the disclosures required by FAS 69 include separate disclosures of the enterprise's share of the investee's (1) proved oil and gas reserves; (2) standardized measure of discounted future net cash flows; (3) capitalized costs relating to oil and gas producing activities; (4) costs incurred in oil and gas property acquisition, exploration, and development; and (5) results of operations from producing activities. These requirements are discussed in Chapters Twenty-Eight and Twenty-Nine.

The equity method is used by many operators who invest in oil and gas partnerships. It is justified on the basis of Accounting Principles Board Opinion No. 18. Opinion No. 18 was written to provide guidelines for investments in corporate stock, but *AICPA Accounting Interpretation No. 2* suggests that many of the provisions of Opinion No. 18 are appropriate guides for investments in partnerships. The Opinion suggests that the equity method should be used when an investor has the ability to exercise significant influence over operating and financial plans of the investee. Under Opinion No. 18, it is presumed that if the investor owns 20 percent or more of the investee's stock, the investor does exercise significant influence.

Opinion No. 18 does not apply, however, when more than 50 percent of the investee's stock is owned; in the latter event, a full consolidation of the statements of the two entities is normally required.

The same logic should apply to partnership investees. However, proportionate consolidation, rather than full consolidation, of the partnership is usually made when the investor's ownership interest is greater than 50 percent.

The major shortcoming of the equity method of reporting the partnership investment is that full disclosure of all pertinent financial information is not given in the financial statements. *Off-balance-sheet financing* may result because the investor may be liable for significant partnership debts that are not reflected in the balance sheet. Paragraph 20 of Opinion No. 18 indicates that disclosure of summarized financial information of such investees may be appropriate for material investments.

Comments on the Proportionate Consolidation Method

A major advantage of the proportional consolidation approach is that it gives a complete economic picture of all elements of the financial affairs, including the investor's share of the investee's liabilities.

Note that X Corporation's final net income in Figure 24-1 is the same as that under the equity method. Having the same net income under either method is normal under successful efforts accounting, but not for full cost accounting. If the partner uses the full cost method, the proportionate share of the partnership's assets and partnership's proved reserves in each cost center must be included with those owned directly by the partner in computing the partner's depreciation, depletion, and amortization (per Reg. S-X Rule 4-10(c)(3)(v) as discussed in FRR 406.01.c.v. at App. 1-18). In such a case, the recomputed DD&A for consolidating the cost center likely will cause consolidated net income to differ from that under the equity method, even if the partnership uses the full cost method, because the ratio of production to reserves will likely change, as in the following example:

Full Cost Example:	*Partner's Direct Holding*	*Partner's Share in Partnership*	*Consolidated*
A. Cost basis	$10,000,000	$2,000,000	$12,000,000
B. Barrels produced	200,000	40,000	240,000
C. Barrels of reserves	1,800,000	160,000	1,960,000
D. Ratio of B/(B+C)	10.0%	20.0%	10.91%
E. Amortization (A x D)	$1,000,000	$400,000	$1,309,091
Amortization/bbl.	$5.00	$10.00	$5.15

For this example, the combined amortization using the equity method is $1,400,000, whereas the consolidated amortization is $1,309,091 using the required partial consolidation of cost basis, production, and reserves.

If both the partnership and the partner use the successful efforts accounting method (as in Figure 24-1 above), it is normally a simple matter to combine the investor's separate statements with those of the investor's proportionate interest in the partnership's financial statements.[82]

If both the partnership and the partner use full cost and the partnership has applied a ceiling test with a resulting write-down of capitalized costs,

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[82]Oi5.121 and Oi5.126 on successful efforts DD&A do not specifically require that proportionate consolidation reflect recomputations of DD&A by consolidated cost centers. Such DD&A recomputation is consistent with Oi5.164(b) requirements to combine reserves, but recomputation rarely changes DD&A significantly by lease or field. Recomputing DD&A will not change total consolidated DD&A unless the ratio of production to reserves (P/R ratio) differs for the partner's direct and partnership interests, as occurred in the preceding full cost example. For a successful efforts cost center (typically a lease or a field), it is rare for a direct interest's P/R ratio to significantly differ from the indirect interest's P/R ratio, unless there is a reversion for one of the interests or the partner's reserve estimate differs from the partnership's.

the partner's share of the write-down should be added back and the ceiling test applied to total cost and total value of the combined assets in the cost center.

If the partnership uses full cost and the partner uses successful efforts accounting, it may be difficult for the partner to convert all partnership statement items to the successful efforts method with a high degree of accuracy.

When the proportionate consolidation method is used, the investor incorporates in its disclosures its proportionate share of each of the investee's applicable disclosure items, regardless of whether full cost or successful efforts is followed.

There may be many transactions between a general partner and the partnership. Accounting for such transactions is addressed later in this chapter.

LIMITED PARTNERSHIPS

In the last three decades, particularly prior to the 1990s, thousands of limited partnerships were formed to finance oil and gas activities. Almost all of these had a single oil and gas operator as the *sponsor* and general partner, with individual investors as limited partners. Such partnerships may be *drilling funds*, *income funds*, or hybrid versions. *Drilling funds* are formed to acquire, explore, and drill unproved properties, whereas *income funds* (also called *production funds*) are formed to acquire, fully develop, and operate proved producing properties.

ACCOUNTING AND REPORTING AT THE PARTNERSHIP LEVEL

In organizing partnerships, certain costs must be incurred. These *organization costs* are especially high for limited partnerships and are related to legal activities (e.g., attorneys' fees for drawing up and filing the articles of partnership and filing fees or other fees charged by the state) and to activities of promoters and organizers in forming the entity. If costs of these types are borne by the partnership, they should be expensed following the guidance of SOP 98-5, same as for general partnerships.

Limited partnerships typically incur *syndication fees*, primarily broker commissions for selling the limited partnership interests. Broker commissions, which usually range from five percent to ten percent of the subscription price of the limited partnership interests, are customarily paid from the proceeds of the limited partners' contributions. Syndication fees also include the cost of prospectuses or private placement memoranda, but these may be paid by the general partner. Theoretically, these costs should be treated as an offset against the partners' capital accounts in the same way that costs related to issue of capital stock by a corporation are treated. A few partnerships and general partners charge such costs to expense at the time they are incurred.

The general partner who sponsors the partnership (or an affiliate of the general partner) charges a fee for management services provided and is reimbursed for costs incurred. Fees and costs related to acquisition, exploration, and development are accounted for in conformity with the accounting method adopted, whereas fees and costs related to production are charged to current expense. Management fees are frequently paid in advance by the partnership. Prepaid costs may properly be deferred and charged to the asset accounts or to expense as the related services are performed by the general partner.

Limited partnership interests may be sold in units of a certain amount in advance or may be structured to obligate the limited partner to a total capital commitment for the life of the partnership. In the latter case, the managing partner may make calls for capital contributions up to the total capital commitment amount, which will usually involve large sums in the first year or two in order to fund the acquisition, exploration, and development of properties.

Limited partnerships, like general partnerships, may adopt either the full cost method of accounting or the successful efforts method; many of them use the income tax basis of reporting to partners because this is often the chief concern of the limited partners. In addition to the usual problems of financial reporting, partnerships may come under the jurisdiction of the SEC. The legal requirements for exemption from SEC registration are beyond the scope of this book.

REPORTING THE PARTNERSHIP INVESTMENT

General partners in limited partnerships, like those in general partnerships, have used either the equity method of accounting or the proportionate consolidation method (see page 584). If the general partner controls the partnership (and the limited partners do not have rights indicative of significant control), then full consolidation would be required.

The February 23, 1999, Exposure Draft (revised), "Consolidated Financial Statements—Purpose and Policy," proposes that a *controlling entity* consolidate all entities it controls unless control is temporary. The ED provides that, absent evidence to the contrary, a sole general partner in a limited partnership is deemed to control the partnership.

For several reasons, proportionate consolidations of interests in limited partnerships are more complicated than those for general partnerships. The sponsoring general partner may also own a limited partnership interest, making it more difficult to compute the general partner's total share of each item. In most limited partnerships, the interests of the general partner and the limited partners will be different for different items of costs and revenues. These varying percentages are usually the result of federal income tax considerations. Limited partners are often given special tax allocations to encourage them to invest. Thus, it is customary for limited partners to provide funds for intangible drilling and development costs, which are deductible for tax purposes when they are incurred. Conversely, general partners provide funds for capital outlays such as leasehold costs, seismic costs, and equipment costs. Revenues may be allocated in one proportion until *payout*, then on a different ratio thereafter. In many arrangements, the relative interests may change because of the partners' option to participate or not participate in further assessments against the partners. The limited partners are required to pay in full for their limited partnership interests at the time the interests are acquired, but the cash contributions of the general partner are often made only as the general partner's share of costs is incurred. Sometimes the general partner is required to make some minimum contributions by a specified date. As a result, it is often difficult to compute the portion of each asset and liability that should be assigned to each party in a proportionate consolidation.

Since the limited partnership may be viewed as a pooling of capital, the general partner and the limited partners should follow the general guidelines of Oi5.138(b) through Oi5.138(f), which require each party to account for the costs it incurs in accordance with the nature of the costs.

Thus, under full cost all costs incurred for exploration and development are capitalized, whereas under successful efforts only successful exploratory drilling and all development costs are capitalized.

Since the managing general partner prepares the financial reports for the partnership, it is customary for the partnership reports to be prepared on the same basis used by the general partner if GAAP reports are prepared. As previously pointed out, many limited partnership statements are prepared solely on a tax basis if the partnership interests are not publicly traded. But if the managing or general partner issues financial statements according to GAAP, the books should be kept in sufficient detail to allow easy translation to both GAAP and tax bases.

The schedule below is typical of the provisions for allocating revenues and costs between the limited partners and general partners, although some allocation schedules are much more complex.

	Percent Provided By:	
	Ltd. Partner	Gen. Partner
Organization costs	0	100%
Initial management fee (5% of subscriptions)	100%	0
Leasehold acquisitions	0	100%
Initial wells:		
Drilling and other noncapital costs, (tax) including equipment abandonments	99%	1%
Capital costs (tax)	0	100%
Subsequent wells abandoned within 60 days of commencing production:		
Noncapital costs (tax)	99%	1%
Capital costs (tax)	0%	100%
Subsequent wells abandoned more than 60 days from commencement of production:		
Noncapital costs (tax)	50%	50%
Capital costs (tax)	50%	50%
Delay rentals	99%	1%
Operating expenses	50%	50%
Production proceeds	50%	50%

The sharing ratios are spelled out in the limited partnership agreement. The agreement requires careful reading in many cases to ascertain what the specific wording means with regard to sharing. Further complication may come in the form of changing ratios over time due to some economic event, such as determinations as to exploratory stage, development stage, and production stage with regard to a property or group of properties. The agreement may call for the general partner to receive a greater interest in the partnership when the limited partners have received cash withdrawals equal to their original capital contributions.

TRANSACTIONS BETWEEN THE PARTNER AND THE PARTNERSHIP

In both general partnerships and limited partnerships, transactions with the general partner may create difficult accounting questions. This is especially true in limited partnerships, in which the general partner is typically the organizer and sponsor of the venture and also manages it. In this chapter, three types of transactions are examined: the sale or transfer of properties to the partnership by the partner; organization, promotional, and managerial activities; and contractual services (e.g., drilling) performed by the partner for the partnership. The appropriate accounting treatment of revenues received and costs incurred by the partner in such activities generally depends on whether the partner uses the full cost method or the successful efforts method of accounting

CONVEYANCE OF MINERAL INTERESTS TO THE PARTNERSHIP

As pointed out above, the general partner may contribute unproved properties to the partnership in return for a partnership interest. Frequently, the general partner will sell to the partnership, for cash or other consideration, all or part of the interest in unproved properties for exploration and drilling. The accounting treatment to be accorded such conveyances when using the full cost method is quite specific.

General Rules for Conveyances under the Full Cost Method

Under the full cost method, an oil or gas operator is deemed to be in *one line of business* (oil and gas exploration and production) for all transactions involving properties in which the operator has an interest.

Other activities related to such properties (e.g., lease brokerage, lease promotion, and management) are viewed as merely a part of the basic exploration and production function. Under the full cost theory, all costs incurred in exploration and development are treated as part of the full cost pool, and all proceeds related to mineral properties, other than from oil and gas production, are deemed to be recoveries of the full cost pool. As discussed in Chapter Twenty-One, Reg. S-X Rule 4-10(c)(6)(iii)(A), as amended in 1984, provides that there shall generally be no recognition by a full cost company of any gains from the sale or conveyance of properties to entities or activities in which the transferor has an interest, but that all proceeds are to be treated as recovery of cost in years beginning after December 15, 1983:

> (iii)(A) Except as provided in subparagraph (c)(6)(i), all consideration received from sales or transfers of properties in connection with partnerships, joint venture operations, or various other forms of drilling arrangements involving oil and gas exploration and development activities (e.g., carried interest, turnkey wells, management fees, etc.) shall be credited to the full cost account.

The exception referred to above is for sale of properties that significantly alter the relation between capitalized costs and proved reserves. Prior to 1984, it was common for operators using the full cost method to segregate unproved mineral properties acquired for the purpose of resale or transfer to partnerships from the full cost pool. Properties thus segregated were treated as an inventory of assets held for resale and were excluded from the full cost pool in computing amortization and in applying the cost ceiling test. Since the properties were considered as inventory and reported as such in the balance sheet, gain or loss would be recognized on their resale or on their transfer to partnerships. Although the SEC previously recognized, under certain circumstances, this *two lines of business* concept, the change in rules eliminated the *inventory* concept for properties acquired in years beginning after December 15, 1983. Now all such properties are deemed to be a part of the full cost pool and treated in a manner identical to that for properties acquired for exploration and drilling.

Reg. S-X Rule 4-10(c)(6)(iii)(A) generally prohibits recognition of income from a full cost company's sale or transfer of property related to partnerships, joint ventures, and other forms of drilling arrangements (e.g., carried interests, turnkey wells, etc.), except:

> to the extent of amounts that represent reimbursement of organization, offering, general and administrative expenses, etc., that are identifiable with the transaction, if such amounts are currently incurred and charged to expense.

For example, if the partnership pays the general partner $500,000 for reimbursement of administrative expense, when the general partner expensed only $200,000 in identifiable G&A costs, then only $200,000 of the reimbursement may be recognized as income. The rest must be credited against the full cost pool. These rules for property sales under full cost accounting are summarized in Figure 24-2.

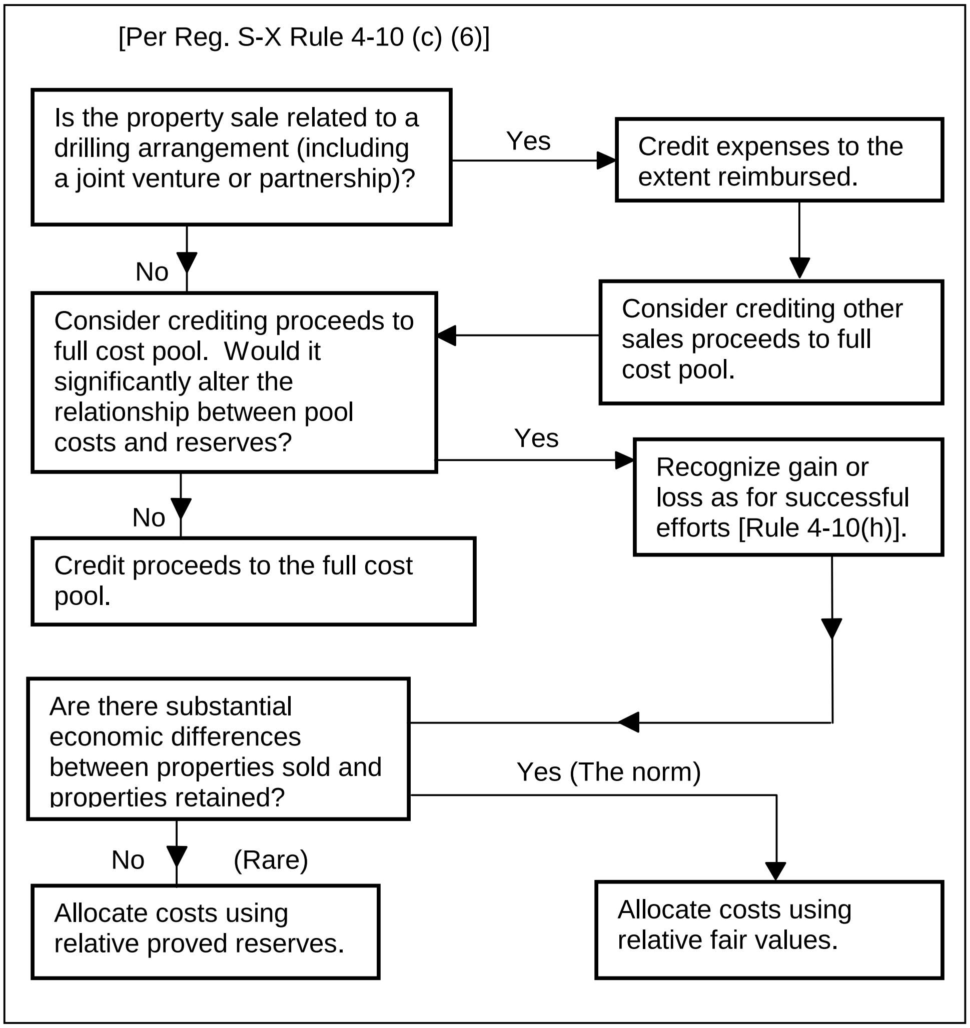
General Rules for Conveyances under the Successful Efforts Method

Section (c) of Reg. S-X Rule 4-10 applies only to companies using the full cost method. Operators using the successful efforts method are not affected by the rule quoted above. Thus if a property originally purchased for exploration and drilling is transferred to a partnership by a successful efforts company, the transaction would be treated in the manner described in Chapters Twenty-One through Twenty-Three. Any cash or other consideration received is treated as a recovery of cost. Only if the consideration received exceeded total cost of the property will gain be recognized (see Chapter Twenty-One).

In circumstances in which no cash is recovered but other partners provide contract drilling services or other services as assets, the transactions are to be viewed as a pooling of capital, and no gain or loss recognized (see Chapter Twenty-Three).

Reg. S-X Rule 4-10 and Oi5 do not prohibit a successful efforts company from reporting an inventory of properties held for resale or promotion under the *two lines of business* concept. However, if the company were to maintain an inventory of unproved properties held for resale or promotion, Oi5.133 through Oi5.138 on mineral conveyances would still seem applicable.

Figure 24-2: Property Sales Under Full Cost Accounting



MANAGEMENT AND SERVICE FEES

Accounting Under Full Cost

In general, income is not recognized for management and service fees by a full cost company. An exception is made in certain circumstances for the promoters of income funds. Reg. S-X Rule 4-10(c)(6)(iii)(B) provides as follows:

> Where a registrant organizes and manages a limited partnership involved only in the purchase of proved developed properties and subsequent distribution of income from such properties, management fee income may be recognized provided the properties involved do not require aggregate development expenditures in connection with production of existing proved reserves in excess of ten percent of the partnership's recorded cost of such properties. Any income not recognized as a result of this limitation would be credited to the full cost account and recognized through a lower amortization provision as reserves are produced.

The rules of Paragraph (iii)(B) may be illustrated by the following example. Our Oil Company organizes a production fund in which Our Oil Company is the general partner and is to serve as manager. Total cost of the proved properties, most of which were developed, was $28,000,000. Estimated cost to complete development of the properties is $5,000,000. During the year, management fees of $800,000 were received. Related expenses were $320,000. Since the additional development costs required are more than ten percent of the partnership's costs related to the properties, Our Oil Company will treat the $480,000 excess of fees over actual costs as a reduction of the full cost pool. On the other hand, if the additional development costs had been only $2,000,000 (less than ten percent of the partnership's property cost), net income of $480,000 ($800,000 less $320,000) could be recognized.

Reg. S-X Rule 4-10(c)(6)(C)(iv) provides that if a full cost company is manager of the properties involved, no income can generally be recognized from rendering contractual services such as drilling:

> Notwithstanding the provisions of (A) and (B) above, no income may be recognized for contractual services performed on behalf of investors in oil and gas producing activities managed by the registrant or an affiliate. Furthermore, no income may be recognized for contractual services to the extent that the consideration received for such services represents an interest in the underlying property.

For example, assume that Our Oil Company, a full cost company, is the general partner, sponsor, and manager of a limited partnership. During the year Our Oil Company drilled a well to the casing point at a fixed fee of $320,000. Our Oil Company's share of these costs was 25 percent, and the limited partners' share was 75 percent. Total costs incurred on the project were $280,000. Our Oil Company should credit the full cost pool for the entire $40,000 drilling profit. Profit of $10,000 is credited to the pool by eliminating the intracompany drilling profit on Our Oil Company's 25 percent share of well costs. An additional $30,000 is credited to the pool so as not to recognize drilling profit on the investors' well costs.

When a company maintains a separate contract drilling division, segmental income statements will normally be prepared. In preparing the consolidated income statement, the intracompany profit on the drilling contract will be eliminated, and the profit resulting from that portion of the drilling contract applicable to partners will be offset against the cost pool, as shown in the following example, based on the example in the preceding paragraph.

	Drilling Segment	Intracompany Elimination	Consolidated Amount
Contract Drilling Revenue	$320,000	$(80,000)	$240,000
Contract Drilling Expense	(280,000)	70,000	(210,000)
Net Income on Contract	$ 40,000	$(10,000)	30,000
Less Full Cost Pool Credit			(30,000)
Consolidated Net Income from Drilling			$ 0

Reg. S-X Rule 4-10(c)(6)(iv)(A) provides that when an interest is acquired in connection with a service contract, or within one year prior to or subsequent to the date of such a contract, income may be recognized to the extent that the cash consideration received exceeds all related contract costs plus the partner's share of costs incurred and estimated to be incurred *in connection with the properties* (but only *if* the partner or an affiliate is not the manager of the oil and gas activity). *In connection with the properties* is a vague term. It appears to include acquisition, drilling, and development costs to be capitalized in the full cost pool but not production costs to be expensed.[83]

For example, assume that Our Oil Company performs drilling services, receiving cash of $640,000 from the partnership. Total drilling costs were $560,000. Our Oil Company contributes cash of $64,000 for its ten percent share of drilling costs, pays $10,000 for its ten percent share of working interest in the lease, and pays $10,000 to an outside service company for its share of completion costs. The $560,000 of contract costs plus the $84,000 to be capitalized to the full cost pool exceeds the $640,000 cash

[83]The SEC's Codification of Financial Reporting Releases, 406.01.c.iv., includes an example computation that includes acquisition, exploration, and development costs but not production costs.

received by $4,000. No income may be recognized, and the full cost pool is charged for a net $4,000. The following schedules illustrate how these facts would be shown in Our Oil Company's income statement and balance sheet after eliminating intracompany profit on the ten percent share of drilling costs.

Income Statement:	Drilling Segment	Intracompany Elimination	Consolidated Amount
Drilling Revenues	$640,000	$(64,000)	$576,000
Drilling Expenses	(560,000)	56,000	(504,000)
Net Drilling Income	$ 80,000	$ (8,000)	72,000
Less Full Cost Pool Credit (see below)			(72,000)
Recognized Profit			$ 0

Balance Sheet:	E&P Segment	Elimination: Intraco. Profit*	Elimination: Drilling Profit**	Consolidated Amount
Leasehold Cost	$10,000	$ 0	$ (6,000)	$4,000
Drilling Costs	64,000	(8,000)	(56,000)	0
Completion Costs	10,000	0	(10,000)	0
	$84,000	$(8,000)	$(72,000)	$4,000

* Intracompany profit (see income statement schedule).

** Total drilling profit = $72,000. (Eliminated first against drilling costs, $56,000; then against completion costs, $10,000; then against leasehold cost, $6,000.)

If in the above case the total profit attributed to the other partners had been $9,000 greater ($81,000, rather than $72,000), profit of $5,000 could have been recognized (if Our Oil Company or an affiliate were not managing the property) because cash proceeds would have exceeded all related costs by that amount. Note that the consideration received must exceed costs already incurred and those estimated to be incurred by the partner before profit can be recognized.

If the E&P company also operates as an independent drilling contractor performing services for other entities in which the E&P company has no economic interest and is not manager of the venture, profit on drilling or other services may be recognized.

Reg. S-X Rule 4-10(c)(6)(iv)(B) allows profit to be recognized, even though the E&P company has an interest in the properties, *provided* that the interest was obtained at least one year before the date of the service contract and the interest is unaffected by the service contract. No income can be recognized to the extent that the compensation received for the service is in the form of an interest in the properties involved.

For example, assume that Our Oil Company has owned for three years a 25 percent ownership interest in a partnership which holds a working interest in a prospect managed by another company. Our Oil Company's share of the leasehold interest cost was $180,000. During the current year, Our Oil Company entered into a contract to drill a well on the prospect for a contract price of $800,000. The well was successful. Total drilling costs were $680,000. Our Oil Company can recognize the $120,000 of drilling profit except for the 25 percent intracompany share.

Our Oil Company's consolidated income statement would reflect the following data related to the drilling contract:

	Drilling Segment	Intracompany Elimination	Consolidated Amount
Income Statement:			
Contract Drilling Revenue	$800,000	$(200,000)	$600,000
Contract Drilling Expense	(680,000)	170,000	(510,000)
Net Drilling Income	$120,000	$ (30,000)	$ 90,000

	E&P Segment	Intracompany Elimination	Consolidated Amount
Balance Sheet:			
Full Cost Pool:			
Leasehold Cost	$180,000		$180,000
IDC	200,000	$(30,000)	170,000

The above rules for recognizing service income under full cost accounting are summarized in Figure 24-3.

Accounting Under Successful Efforts

The special rules in Reg. S-X Rule 4-10 relating to partnerships, joint ventures, drilling arrangements, management fees, and service income are found in Section (c), relating to full cost companies. It may thus be concluded that the limitations on income recognition do not apply to managing partners using the successful efforts method. It is therefore common for such managing partners to treat management fees as income when earned in accordance with the terms of the management contract.

Management fees paid upfront should not be reported in full as income in the year received but should be deferred and recognized as the related services are rendered. If the up-front fee is designed in part to reimburse offering costs and other expenses associated with the partnership, the expenses may appropriately be charged to expense and the related reimbursement reported as income. A successful efforts company would expense nonreimbursed offering costs.

If the successful efforts method is followed by the operator, there are no special restrictions on the recognition of income, other than the normal rules for elimination of intracompany profit. For example, suppose the sponsor who owns a 25 percent working interest and is manager of a limited partnership drilled a successful well for the partnership for a contract fee of $500,000. Total costs incurred in drilling the well were $400,000. It would be appropriate for the partner to recognize a profit of $75,000 ($100,000 less intracompany profit of $25,000) on the contract if the successful efforts method is used.

G&A REIMBURSEMENT

Most limited partnership agreements provide for reimbursement of general and administrative expenses. The reimbursement may cover specific general and administrative expenses, in which case the reimbursement should be reported by the general partner as a reduction of expenses. The reimbursement may be a specified monthly amount, but normally it is computed as a percentage of partnership revenues or as a percentage of specified costs incurred. Frequently the rate is higher during the drilling phase of the partnership than during the production phase.

MASTER LIMITED PARTNERSHIPS

The mid-1980s saw the development of *master limited partnerships* (MLPs). In many cases MLP interests, referred to as *depository units*, have been freely traded in the over-the-counter market and have sometimes been listed on the organized stock exchanges. MLPs whose units are publicly traded are frequently referred to as *publicly traded limited partnerships* (PTLPs). By 1999, many MLPs had been acquired by corporations or reorganized as taxable corporations. MLPs are now rare in the E&P industry.

An MLP (often newly formed) which is to be an E&P company may offer to issue its units of ownership in return for some type of direct or indirect interest in oil and gas properties. Frequently, the units are offered to limited partners for their interests in existing partnerships so that two or more limited partnerships are combined. In other cases, units in the MLP are offered for working interests or for royalties. The combining of existing limited partnerships and the acquisition of properties through the issue of units of ownership in an MLP are referred to as *rollups*. The offer to exchange the units for mineral properties or for partnership interests is referred to as an *exchange offer*.

The major advantage of a publicly traded MLP is that it allows the investor to avoid corporate taxation and gives the investor a means for easily converting its limited partnership interest into cash. This contrasts dramatically with the ownership of normal partnership interests, which have very little liquidity. An MLP rollup permits a new company to own producing properties from the outset of its activities so that it offers many advantages in its financing activities and has strong investor appeal. The MLP resulting from the rollup may be substantially larger than its predecessor partnerships. The large size may give a better competitive position to the new MLP.

In the past, some MLPs have been formed when an existing corporation contributed interests in oil and gas properties to an MLP and then distributed the limited partnership units to its existing shareholders in partial or complete liquidations of the corporations. Because of current tax laws, this is a far less desirable move than in the past and will not likely be a frequent occurrence in the future.

The major disadvantage of an MLP rollup is the high cost involved to form and administer the MLP. The administrative details and the large amount of time required to develop the information to be provided to offerees are quite costly. There are high compensation costs for (1) the securities firm retained as the dealer-manager; (2) for professional fees of attorneys, accountants, and engineers; (3) for preparing, printing, and distributing offering documents; and (4) for establishing an organization to manage the new company. The sponsor of the exchange offer and other investors provide funds to administer the undertaking. The sponsors of the MLP may be allocated some portion of the units in the acquiring MLP in return for the funds to finance the venture and for providing services to create and administer the rollup. If the venture is successful, this interest may represent a substantial asset.

The accounting issues for MLPs are essentially the same as those for private limited partnerships. However, the accounting problems faced in forming an MLP, especially one that is publicly traded, may be more complex, depending on the nature of the MLP. One major problem is in determining exchange values. Another problem is in complying with the FASB and SEC requirements for recording the formation.

DETERMINING EXCHANGE VALUES

One of the most important and most difficult steps in an exchange offer is determining the number of units that will be offered to owners of interests in the properties included in the offer. Each offeree must be treated fairly and equitably in relation to the other offerees. This is accomplished through an allocation of shares that is based on the exchange value of the property interests included in the offering. Since proved reserves represent the most important asset involved in exchange offers, the estimated value of proved reserves attributable to each interest is the major factor in determining the shares offered for each interest.

The starting point in computing the exchange value of an interest is a projection of future production from the proved reserves. The production schedule is then converted into future net revenues from the estimated production. These net revenues are based on assumptions about future prices of oil and gas and future costs to develop and produce these reserves. Once the future net revenue has been estimated, it is then reduced to a present value using a specified discount rate.

Exchange value calculations also may provide for *probable* reserves or even *possible* reserves. Since these reserves are much more subjective and less certain than proved reserves, the discounted cash flow from their production is further reduced by an adjustment necessary to give effect to the uncertainties. For example, the value of the exchange offer could be based on the formula of 100 percent of proved, 50 percent of probable and ten percent of possible reserves. If undeveloped acreage is included in the exchange offer, it will probably be evaluated by independent appraisers.

The specified present value discount rates and the risk adjustments for probable and possible reserves are generally applied consistently among all partnerships forming the MLP. Ideally, exchange values should closely approximate fair values. However, the exchange values may be fair without approximating fair values. The use of a uniform, consistent approach to determining the exchange values may be viewed as fair if their relationship to each other is generally the same as that using fair values. In theory, if all exchange values are 15 percent below their fair values, the proportionate ownership of the MLP would be the same as if fair values were used instead. However, when properties are substantially different among the partnerships, caution must be exercised in the use of a consistent discount rate that provides a relationship of exchange values substantially different from the relationship of fair values.

At the time of the evaluation for exchange purposes, it will be necessary to develop data to comply with the SEC's disclosure requirements for proved reserves if the partnership is subject to the SEC's rules, as is likely the case. The basis for these disclosures may be different from the basis used in arriving at the exchange value. The SEC's disclosure requirements for quantities and discounted present value of proved reserves are based on price and cost factors as of the date of the statements and on a uniform discount rate of ten percent. The value for exchange offer purposes, on the other hand, may be based on expected price and cost factors and on an assumed discount rate that is related to the cost of capital and other factors.

COSTS OF UNDERTAKING MLP EXCHANGE OFFERS

Paragraph 58 of Opinion No. 16 required that the administrative costs of consummating business combinations be charged to current expense in the period incurred. Arguably, costs incurred in undertaking MLP exchange transactions are more akin to those necessary to create a new company than to consummate a business combination. Hence, prior to SOP 98-5, many MLPs capitalized the exchange costs. Today, following the guidance of SOP 98-5, MLP start-up costs are expensed as incurred.

Chapter Twenty-Five

ACCOUNTING FOR INTERNATIONAL OPERATIONS

International operations comprise a major segment of the operations of most large E&P companies. Operating outside the U.S. presents a very diverse and complex set of legal, accounting, and financial reporting issues. This chapter presents several key issues to introduce the reader to the challenges of accounting for international E&P operations.

Outside the U.S., mineral interests are commonly owned by the host country government and not by private citizens or private corporations. The host country acts within its legal and economic environment in establishing the basic contractual framework that provides the E&P company the opportunity to explore, develop, and produce minerals. These contracts are subject to limited negotiations and bidding by the E&P company and its competitors.

Once the contracting terms are defined and agreed upon, a company undertakes the exploration and development of a specific area under a well-defined work program and budget. The E&P company is obligated to provide funds and equipment for exploration and development and bears the risks of failure. Once production equipment or facilities are commissioned, landed-in-country, or placed-in-service, title to the equipment normally passes to the host government. The company typically has the right to share in the oil and gas produced or the proceeds from the sale thereof for a fixed number of years and must look to income derived from production for a return of its operating and capital expenditures.

RISKS OF INTERNATIONAL E&P

Many countries offer opportunities for petroleum exploration and production. With international operations, there are increased economic risks. Each country (and sometimes areas within a country) has its own set of risks to address in addition to the normal risks inherent in petroleum exploration and production. It is important for company management to know and understand these additional risks and to assess their impact on the company's ability to earn a profit in the global market.

POLITICAL INSTABILITY

When considering an area in which to operate, the company must address the stability of the political regime in and around the country in question. If the government changes, the new government may not recognize or honor existing contracts and agreements that were entered into by the previous government. In some countries laws change frequently, sometimes with retroactive application. In one case, different taxes based on revenue, not income, resulted in an effective combined income tax rate exceeding 100 percent—obviously eliminating the economic incentive for exploration and production.

Border disputes can be a problem, especially offshore. The problem is that a company can be awarded a license from one country, then explore, drill, and find commercial reserves, only to be told by another country that the area in question is claimed by the other country. Border disputes of this nature, especially after reserves are found, are not usually resolved quickly.

In a few countries, civil wars and guerrilla activities also present physical and financial risks.

FOREIGN CURRENCY RISKS

Oil prices are generally quoted worldwide in U.S. dollars, but gas revenue, as well as costs and expenses, are often expressed in the local foreign currency. This foreign currency will probably be the functional currency, so it is important to understand the stability of that currency in relation to the U.S. dollar. An unstable currency exchange rate brings with it translation and hedging problems. Further currency problems exist in regard to settlements and repatriation. For settlements, the question of converting profits to U.S. dollars comes into play, and with repatriation of funds, the question is how, when, and how often the company can get its investment and profits out of the foreign country and returned to the U.S. Sometimes repatriation can be a double-edged sword, with foreign currency exposure and government restrictions internationally and U.S. tax laws at home.

ACCOUNTING OPERATIONS RISKS

In some underdeveloped countries, the accountant faces risks of limited logistical support, inadequately trained local accountants, high staff turnover, extremely limited or unreliable phone lines and computer equipment, and even a shortage of modern housing and other facilities.

Considerable time may be spent in the early stages to establish a local accounting department and an adequate accounting system in light of local conditions and restrictions.

FORMS OF OPERATION IN A FOREIGN COUNTRY

THE E&P COMPANY'S LOCAL SUBSIDIARY

Quite often companies set up a foreign subsidiary for each country in which they plan operations. The subsidiary is then registered with the host government before any agreements are negotiated. The foreign subsidiary is the party to all agreements and becomes the operator of record. It will have a set of books and its own funding for foreign purposes, although it may be little more than a shell company, and the real financial records for U.S. GAAP purposes are kept elsewhere and in a different format. With the foreign subsidiary established in name only, it is quite possible to initially operate in a foreign country with nothing more than a field office on site.

The SEC staff views pro-rata consolidation to be inappropriate for interests in jointly controlled corporate entities, even if there is an agreement which attributes benefits and risks to the owners as if they held undivided interests. The staff views pro-rata consolidation appropriate for interests in partnerships and other noncorporate forms of joint ownership only if such interests are equivalent to holding undivided interests in assets (with severable liability for incurred related indebtedness) as described in SOP 78-9.

OPERATING IN A JOINT VENTURE

E&P joint ventures are common for international operations. Joint venture partners might include a non-U.S. company, perhaps even the local national oil company. The venture operator should have an accounting and reporting system in place that can deal with all requirements of the foreign country as well as U.S. reporting requirements.

A 1995 *Model Form International Operating Agreement* and a 1992 *Model Form Joint Accounting Agreement* are available from the Association of International Petroleum Negotiators (AIPN).

INTRODUCTION TO FISCAL SYSTEMS

A significant accounting issue for international E&P is properly determining the agreed sharing of venture profits between the E&P company and the host government. The sharing arrangement, sometimes called the *fiscal system*, encompasses all means (such as bonuses, royalties, profit sharing, and income taxation) by which the host government and the E&P company share in the venture production and profits. Variations in fiscal systems are numerous but generally fall into one of two basic types:

- The concession, much like a lease in the U.S., whereby the E&P company typically owns the discovered reserves and has title to oil and gas as produced while the government's share is largely determined by bonuses, royalties, and income taxation, and
- The contractual arrangement whereby the government typically owns the reserves and even the field equipment but licenses the E&P company as a contractor to perform or manage specified E&P activities. The company's fee may be in cash (a *service contract*) or in a share of production (a *production sharing contract* or *PSC*) designed to reimburse the company for its E&P costs out of a specified share of the profit, before much of the profit is taken by the government in the form of production sharing and taxation.

In most instances the fiscal system is complex and may also be vague or ambiguous. Multiple sharing formulas, artificial pricing, government inflexibility, changing regulations, cultural differences, and ambiguities in the agreement may arise to complicate and frustrate accounting for the sharing of E&P profits.

The issue becomes further complicated when several E&P companies enter into a joint venture arrangement and deal collectively with the host government. Such arrangements entail the execution of a joint operating agreement that, in and of itself, may introduce an additional tier of accounting-related issues. Additionally, oil takes by venture partners may routinely differ from entitled shares, giving rise to oil imbalances that must be monitored and accounted for.

In general, E&P rewards are shared by six means, described briefly below:

- Up-front and periodic *bonus payments* to the host country,
- Periodic *royalty payments* to the host country,
- Allocation of revenue to the E&P company for *recovery of investments and operating costs*,
- *Profit sharing* (or *profit splitting*),
- *Taxation* by the host country, and
- *Infrastructure development* for the host country.

BONUS PAYMENTS

The negotiated E&P agreement may require payment of an up-front bonus upon execution of the agreement. Alternatively, the agreement may call for a reduced up-front bonus (allowing the E&P company to retain its capital for payment of exploration and development costs) with subsequent periodic bonuses referred to as *production bonuses*. Production bonuses are paid by the E&P company upon the achievement of certain agreed upon levels of production. As with U.S. leasing, these bonuses are recorded as a property acquisition cost.

ROYALTIES

Rates and formulas for determining royalties have far more variations than those found in the U.S. Royalties may be computed on different qualities of production using different rates and may be based upon a sliding scale percentage varying with volumes produced.

A royalty based upon units of production is a common means of sharing the rewards of successful exploration and development with the host country and is relatively easy to calculate and audit, since no price determination is required. However, a royalty as a fixed percentage of revenues actually realized is arguably a fairer reward sharing arrangement. So royalties based on the actual sales price, or a published or posted price, are also common. In some countries, royalties are credited against host country income taxes.

Unlike the U.S. practice of reporting revenues net of royalties, local accounting practices outside the U.S. may be to record gross revenues and show royalties as an expense or even as an element of income taxes.

RECOVERY OF INVESTMENTS AND OPERATING COSTS

The host country typically will require the E&P company to bear all costs and risks of exploration and, perhaps, development. Under production sharing contracts, a substantial portion of initial revenue or production typically is allocated to the E&P company as *cost recovery* production until E&P costs are recouped, as illustrated later in Figure 25-2.

The recoverable costs for a particular period are dependent on the PSC agreement terms. Recoverable costs normally include the period's operating costs and may include an amortized amount of prior capital costs or perhaps an amount of prior capital costs up to the maximum revenue available as reimbursement. For example, assume that the E&P company incurred $10 million in prior reimbursable costs. The PSC calls for ten percent amortization, or recovery, each year (i.e., $1 million in the current period). Under the PSC, the current period's revenue available for reimbursement is limited to reimbursable costs not to exceed $4 million. If operating expenses are $500,000, then total cost recovery revenue and reimbursable expenses for the period are both $1.5 million, including the $1 million amortization of prior costs. Alternatively, the PSC may allow the operator to recover a total of $4 million during the year, consisting first of the $500,000 of operating costs of the current year and an additional $3.5 million of prior capital costs.

Under the cost recovery concept, the arrangement usually restricts all cost recovery and/or deductions to production from a specific license (or sometimes a field). This concept is sometimes called *ringfencing*. Under ringfencing, cost recovery is available only for expenditures attributable to the particular license. Costs incurred in one ringfenced license area cannot be recovered from another license area outside the ringfence.

Accounting for cost recovery is a complex issue further addressed later in this chapter.

PROFIT SHARING

Revenues after royalties are shared by the E&P company and the host country based on sharing percentages set forth in the E&P agreement. Thus, the E&P company’s revenues from the joint venture usually consist of two components, often called for internal accounting “cost recovery revenue” and “profit sharing revenue.” The profit sharing revenue is usually net of the host country's share, much like pro-rata consolidation of a joint venture's activities.

TAXATION

Another mechanism that a host country traditionally uses to collect its share of E&P rewards is taxation, primarily income taxation. Some countries have formal income tax statutes, and others make the tax rules governing a particular arrangement part of the contractual arrangements between the host country and the E&P company.

Determining gross taxable income can be difficult. If the company sells the products to an affiliate for a price different from the free market price, then the free market price, if higher, will normally be used in determining gross income for host country income tax purposes. In many countries, use of the free market price is replaced by the use of an artificial posted price for tax determination (and sometimes royalty determination), even if the product is sold on the open market.

Tax systems around the world vary dramatically in defining the deductions that will be allowed in computing taxable income. For example, the agreement may or may not allow the deduction of costs incurred in evaluating and negotiating the E&P arrangement with the host country, including costs at the company's headquarters outside the host country. Another example is costs paid by the E&P company to an affiliate. Host country tax laws or the E&P agreement may or may not allow deduction of all costs paid to an affiliate. For tax purposes recovered costs are generally deducted when recovered. If not then, the costs are deducted through a DD&A provision. Some countries allow the deduction of bonus payments, either in the form of a deduction similar to the United States percentage depletion deduction based on gross income or by allowing more than 100 percent recovery of certain expenditure categories in computing host country income taxes.

Debt financing may be necessary, at least during the development stage of the arrangement. However, interest incurred on indebtedness required for operations in the host country may not be deductible for host country income tax purposes. Some host countries have disallowed all interest payments made outside the host country.

In most foreign jurisdictions, it appears that royalties are normally treated as deductible expenses for host country income tax purposes, rather than being credited against income taxes. U.S. companies prefer that royalties be treated as foreign income taxes because income taxes may be creditable against U.S. federal income taxes. The contract between the host country and the company should clearly identify royalties and income taxes to be sure the tax treatment of such items is clear, not only for host country income tax purposes, but also for home country income tax purposes.

In addition to income taxes, E&P companies operating outside the U.S. encounter numerous other types of taxes. Some countries, such as the UK and Australia, have special petroleum taxes (*petroleum revenue taxes* [PRT] or *petroleum resource taxes*) assessed specifically on petroleum operations. Other countries may assess special *value-added taxes* (VAT). Customs duties and other importation type fees are also another form of taxes that are assessed by host governments.

Financial accounting for foreign income taxes is the same as for U.S. income taxes.

INFRASTRUCTURE COSTS

The host country may require infrastructure development and other industrial developments as part of the overall exploration arrangement. Many countries have insisted on including infrastructure development as part of the arrangement if a company is successful in locating commercial petroleum reserves. In some cases, such development activities are required even during the exploration stage.

The host country generally requests technology and other expertise as part of the arrangement. Many countries have rather limited numbers of personnel qualified in technical petroleum matters. The host country is not only trying to attract the company's capital, but also its expertise. The company generally agrees to reasonable levels of training for host country personnel so that over a period of time the host country will have qualified individuals who can interface with those from the company.

Contracts also often call for the company to construct roads, utilities, housing, and other physical facilities in the area of the exploration and production activities. Training or employment of local personnel and infrastructure development can take many forms, including goodwill gestures that go beyond the requirements of the formal agreement. E&P companies may build roads, bridges, and even housing to foster goodwill and cooperation with the local people. Sometimes the E&P company finds it necessary to provide unplanned support to the local populace.

Accounting for infrastructure costs and local support costs depends on the nature of the costs. Costs that in substance are acquisition, exploration, development, or production are simply accounted for as such. Costs unnecessary for normal E&P activity are forms of bonus (e.g., helping to build a local hospital) or royalty compensation to the host country and should be so recorded.

CONCESSIONS

Concessions are fiscal systems in which the government grants title of mineral rights to the concessionaire. The United Kingdom sector of the North Sea is an example of a concessionary system. Every few years, the UK government opens a bidding round for exploration and development proposals for petroleum licenses on blocks of offshore properties. It then awards concessions to companies, giving them the right to exploit any minerals they find on those properties. The awards are based primarily on the development plan submitted by the winning company. The government gets its share of revenues by assessing royalties and/or PRT on production, VAT on specified costs, and income taxes on company operations in the UK. The companies are generally allowed to sell oil production on the open market, but gas production is usually sold through a contract to a UK gas utility company. In such a concessionary agreement, the company is the owner of all risk and profits from the reserves within government regulations, as in the U.S. and Canada.

EXAMPLE OF ALLOCATING NET PROCEEDS

Multico Company, an E&P company, operates in a concessionary area in the North Sea. The contract between Multico and the UK government requires Multico to pay the government an 8 percent royalty (based on gross revenue) and a 5 percent (of gross revenue) VAT. Multico is responsible for all of the costs associated with exploration, development, and production. Multico’s costs include $10,000,000 in exploration and development during 2002-2004. In 2004, the property goes on production and grosses $5,000,000. Local income tax laws allow Multico to deduct all $1,000,000 in operating costs incurred during the current year as well as 1/5 of all prior exploration and development expenditures. Assuming an income tax rate of 40 percent, the share of net E&P proceeds ultimately accruing to Multico and to the UK government in 2004 are shown in Figure 25-1.

Figure 25-1: Allocation of Net Proceeds for the Multico Example

	To Government	To Multico
Gross revenue		$5,000,000
Royalty 8%	$ 400,000	(400,000)
VAT 5%	250,000	(250,000)
Net revenue		$4,350,000
Operating expenses		(1,000,000)
1/5 of exploration and Development costs *		(2,000,000)
Taxable income		1,350,000
Income taxes at 40%	540,000	(540,000)
Net to the parties	$1,190,000	$ 810,000

* Note: Multico actually paid the exploration and development expenditures in 2002 – 2004.

THE JOINT VENTURE CONCESSION

A variation frequently encountered in a concessionary system involves the host government participating in the oil and gas operations as a working interest owner. This type of arrangement may be referred to as a joint venture arrangement and is a form of *government participation.* The government often sets up a (government-owned) oil company to participate in the operation as a working interest owner. A joint operating agreement may be executed governing the specific details of the operation. The E&P company typically agrees to pay 100 percent of the costs, and the government-owned company is a carried working interest through the exploration phase. If commercial reserves are discovered, the government-owned company has the option to elect to participate in development and production operations as a working interest owner at an interest of up to 51 percent. If the government-owned company exercises its option to participate, it must share in all future drilling, development, and production costs.

Depending on the terms of the contract, the E&P company may be allowed to recover all or a portion of its exploration expenditures. Two methods of recovery are often used. One method is direct payment by the government-owned company to the E&P company. The more frequently used alternative is to allow the E&P company to recover its costs (or certain agreed-upon costs) by retaining the government-owned company's share of production until the it has reached payout (i.e., recovered its costs). Afterwards, the government-owned company shares in costs and production just like any other working interest owner.

This type of arrangement does not alter the government's entitlement to royalty and income taxes; however, customs duties on the importation of materials and supplies and export duties on production are often exempted.

Accounting for a concession interest is similar to that for a working interest in a U.S. mineral lease. The joint venture with a carried national oil company is a pooling of assets, with no gain or loss recognized.

CONTRACTUAL ARRANGEMENTS

In a contractual arrangement the government owns all minerals. The E&P company can earn an interest in the minerals or proceeds from the sale of minerals as a "fee" for the services it performs (i.e., exploration, drilling, development, and production). Typically, the government (via a government-owned oil company) plays an active role in exploration, development, and production; and the E&P company acts as the operator. These contracts typically require formation of a joint management committee to oversee operations and vote on all major operating decisions. The joint management committee is comprised of representatives from each of the companies as well as representatives of the government. The E&P company is typically required to submit an annual work program and budget to the joint management committee for review and approval. The joint management committee generally makes all major decisions regarding the management of the petroleum operations including approval of all major expenditures, evaluation of the results of exploration, planning and drilling of wells, and determination of the commerciality of drilling results.

The E&P company is typically required to provide all technology and financing. In most contractual arrangements, equipment or facilities that are acquired locally or imported into the country become the property of the local government. (This does not apply to leased equipment, equipment brought into the country temporarily, or equipment and facilities that are owned by service companies.) In some instances title to the equipment and facilities passes to the government at the time the goods are brought into the country or upon installation. In other cases, title passes to the government when the cost of the equipment and facilities has been recovered by the E&P company.

Two types of contracts are frequently encountered in international operations: *production sharing contracts* (PSCs) and *service contracts*.

PRODUCTION SHARING CONTRACTS

Production Sharing Contracts, utilized worldwide, are probably the most common form of agreement between host countries and foreign companies to define exploitation of the host's natural resources. PSC terms and conditions vary so widely that it is difficult to present a model PSC.

Most PSCs involve government participation through a government-owned oil company, with the E&P company bearing all costs and risks during the exploration phase. Typically, if commercial reserves are discovered, the government-owned oil company has the right to elect to participate as a working interest owner up to a maximum interest of 51 percent. The E&P company does not receive reimbursement for the government-owned company's share of costs; rather it must recoup its costs from future production. If production is not achieved, the E&P company bears all of the costs without any provision for reimbursement. The government-owned company is typically responsible for its working interest share of development and operating costs.

Cost Oil and Profit Oil

Cost recovery is a fundamental feature of PSCs. As stated above, the E&P company typically pays 100 percent of costs incurred in the exploration phase and some or all of the costs incurred during the development and production phases. The oil (or gas) or other consideration accruing to the parties to recover cost is referred to as *cost oil*, while the gross revenue accruing to the parties after cost recovery or as a result of applying a profit factor is typically referred to as *profit oil*.

The agreement typically specifies which costs are recoverable, the order of recoverability, any limits on recoverability, and whether costs not recovered in one period can be carried forward into a future period. Some contracts call for "amortizing" or "depreciating" the amount of capital costs recoverable in any year (e.g., only 1/10 of allowable capital costs are recoverable each year in the first ten years of production), while other contracts simply employ an annual maximum to cap the amount of total recoverable capital costs in any given year. Typically, there is a ceiling or maximum amount of revenue that is available for cost recovery in any given year. In many agreements, recoverable costs not recovered in any given year can be carried forward to future years.

Some contracts allow the recovery of interest incurred on capital expenditures. The typical Chinese PSC, for example, allows cost recovery on the "deemed" interest related to costs incurred during the development phase but not during the exploration phase. The recovery of interest costs may be a contentious issue since governments generally assume that it is the contractor's responsibility to acquire sufficient funds to cover capital requirements.

The order of cost recovery is important since it determines how quickly the E&P company is able to recover certain costs. For example, if an E&P company pays 100 percent of the costs during the exploration phase and 49 percent of costs during the development phase, the company would prefer that exploration expenditures have priority in cost recovery ahead of development expenditures. Typically costs are recovered in an order similar to the following:

1. Current year operating costs,
2. Unrecovered exploration expenditures,
3. Unrecovered development expenditures,
4. Deemed interest (if allowed),
5. Investment credit or capital uplift (if allowed), and
6. Future abandonment cost fund (if required).

In many agreements exploration and development expenditures are amortized or recoverable over a fixed number of years. If the amortized capital costs are not recovered in any given year, the unrecovered portion may be carried forward and recovered in subsequent years. In some cases, however, carryforward of unrecovered amortized capital costs is not allowed and recoverability is permanently lost.

After determining the amount of production or revenue allocated to cost recovery, the profit oil is shared between the parties based on the terms and conditions set forth in the contract. In some contracts, a specified percentage of gross revenue is treated as profit oil and shared by the parties. In other agreements a percentage of the revenue remaining after cost recovery goes directly to the government with the E&P company and the government-owned oil company sharing the remainder.

Production Sharing Example

Jones Oil Company operates under a PSC agreement in the South China Sea. Jones has 49 percent of the working interest, and Sinhai Oil Company, which is owned by the Chinese government, has 51 percent of the working interest. The agreement calls for annual gross production to be split in the following order:

1. VAT equal to 7 percent of annual gross production
2. Royalty of 13 percent of annual gross production
3. Cost oil is limited to 62 percent of annual gross production with costs to be recovered in the following order:

    a) Operating expenses
    b) Exploration expenditures (Jones Oil Company paid 100 percent)
    c) Development costs (Jones Oil Company 49 percent and Sinhai Oil Company 51 percent)

4. Annual gross production remaining after cost recovery becomes profit oil and is split:

    a) The government receives 15 percent of profit oil, and
    b) The remaining 85 percent is shared by Jones and Sinhai based on their working interests.

During 2002:

- Recoverable operating costs equal $4,000,000,
- Unrecovered exploration costs equal $50,000,000,
- Unrecovered development costs equal $100,000,000,
- Gross production for the year is 2,000,000 barrels of oil, and
- The “agreed upon” posted price is $25 per barrel.

The allocation of production to the parties is shown in Figure 25-2.

In addition, the government’s take would be increased and Jones Oil Company’s share decreased by income taxes and any other taxes levied by the Chinese government.

Figure 25-2: Allocation of Production

	Barrels To Be Allocated	Chinese Govern-ment (in bbls)	Sinhai 51% (in bbls)	Jones Oil 49% (in bbls)
VAT (7% of 2,000,000 total barrels)	140,000	140,000		
Royalty (13% of 2,000,000)	260,000	260,000		
Cost oil (62% of 2,000,000)	1,240,000			
Cost oil allocation:				
For operating costs,				
$4,000,000/$25 = 160,000 bbl			81,600	78,400
For exploration costs,				
$50,000,000/$25 = 2,000,000 bbl,				
limited to 1,240,000 - 160,000				1,080,000
For development costs			0	0
Remainder			0	0
Profit oil: 2,000,000 x				
(100%-7%-13%-62%)	360,000			
Allocate 15% to government and split				
the rest 51% / 49%.		54,000	156,060	149,940
TOTAL	2,000,000	454,000	237,660	1,308,340

Often host governments incorporate certain incentives into the agreement in order to encourage companies to maximize the amount of capital they invest in exploration, drilling, and development. These incentives may appear in PSCs or result from other negotiations.

Capital Uplift

A *capital uplift* is an incentive offered by a host government to encourage E&P companies to maximize their capital spending and to compensate for risk. A capital uplift, sometimes referred to as an *investment credit*, is an additional amount of cost recovery on capital expenditures over and above actual amounts spent. For example, if a company spends $5,000,000 in recoverable capital expenditures and there is a 10 percent capital uplift in the contract, the company will be allowed to recover 110 percent of actual spending or $5,500,000.

Domestic Market Obligations

Some contracts specify that a certain percentage of the E&P company's share of profit oil be sold to the local government, typically at a price that is less than the current market price. This requirement is referred to as the *domestic market obligation* and is often included in situations where the country's demand for crude oil is greater than the government's share of production. The domestic market obligation reduces the government's need to rely on imported oil or oil from more expensive sources.

Royalty Holidays and Tax Holidays

Royalty holidays and *tax holidays* are incentives governments may use to encourage E&P companies to maximize investment early in the life of production. The government may specify a period of time (i.e., the first two years of production) during which the royalty provision is waived, resulting in the E&P company paying no royalty on production during that period of time. This incentive leaves the E&P company with more money to reinvest in drilling and development. The government may similarly grant a tax holiday specifying a period of time during which the E&P company is exempt from income taxes.

Un-ringfencing

Generally, in determining cost recovery, only costs that are expended for work in a particular license area are recoverable from production from that specific area. As such, the costs are said to be *ringfenced*. In other words, costs cannot be transferred outside the area for recovery against revenues from other contract areas, and production cannot be transferred to other contract areas for recovery of costs incurred in those areas. If production in an area is insufficient to allow for full recovery, costs cannot be transferred to another contract area where production is higher and recovered from that production. In these instances the contract areas are said to be ringfenced. An incentive that governments may provide is to un-ringfence or allow cross-fence transfer of the costs. This incentive is most effective when the government is seeking to increase exploration in a particular area by allowing a company to immediately recover certain exploration expenditures in the new, frontier area against production from a different, currently producing area.

FINANCIAL ACCOUNTING FOR THE PSC

Regarded as Oil and Gas Producing Activity

Even though the host country may legally *own* the reserves pursuant to the PSC agreement and governmental laws, the PSC agreement gives the E&P company rights to exploration, development, and production substantially equivalent to owning a mineral interest and owning a share of reserves. The E&P company is engaged in *oil and gas producing activity* as defined in Reg. S-X Rule 4-10. Consequently, it is customary financial accounting and meaningful to financial statement users for the E&P company's PSC rights to be viewed as the equivalent of concession rights. The basic financial accounting rules are the same:

- The E&P company records the PSC activity as oil and gas production activity and not as contractor services.
- The E&P company recognizes reserves to the extent of its share in future production under the PSC (although calculating the share can be much more difficult than for a concession).

In the *1999 PricewaterhouseCoopers Survey of U.S. Petroleum Accounting Practices*, 15 of 17 respondents (88 percent) record the proceeds from the sale of cost recovery oil received under production sharing contracts as oil revenue. No respondents recorded the proceeds as a recovery of capitalized costs. Two respondents used methods not specified in the published survey results.

When the cost recovery proceeds were recorded as revenue, 13 of the 15 respondents (87 percent) amortized capitalized exploration and development costs over the E&P company's entitled share of future production from proved reserves. None simply amortized capital costs by the amount of the cost recovery proceeds.[84] One respondent calculated amortization expense as the portion of cost recovery revenue equal to the portion of capitalized recoverable costs over all recoverable prior costs (including

[84]Amortizing by the amount of cost recovery proceeds has the same effect on income as crediting the proceeds as a recovery of capitalized costs. The former increases revenue and expense by the proceeds amount; the latter does not.

such costs as G&G that were previously expensed).[85] One respondent used another method not specified in the published survey results. These survey results suggest that the usual accounting for production sharing contracts is no different from that for a concession. Proceeds are recorded as production revenues from oil and gas producing activity, and capitalized costs are amortized over the company's share of proved reserves.

Disclosure of Proved Reserves

FAS 69 requires public companies to disclose the net quantities of the enterprise's interests in proved reserves. Per FAS 69, Paragraph 13, such quantities are not to include

> oil or gas subject to purchase under long-term supply, purchase, or similar agreements and contracts, including such agreements with governments and authorities. However, quantities of oil or gas subject to such agreements with governments or authorities as of the end of the year, and the net quantity of oil or gas received under the agreements during the year, shall be separately disclosed if the enterprise participates in the operation of the properties in which the oil or gas is located or otherwise serves as the *producer* of those reserves, as opposed, for example, to being an independent purchaser, broker, dealer, or importer.

The standardized measures of the two reserve disclosures may be combined (FAS 69, Paragraph 30).

The end of the year quantities separately disclosed were called proved reserves in Appendix A to FAS 69. However, FAS 69, Paragraph 102 explains that because such sharing in future production does not "represent direct ownership interests in reserves, those reserve quantities are to be reported separately from the enterprise's own proved reserves."

[85]For example, assume the E&P company received $4 million of cost recovery revenue as reimbursement for $500,000 of current period operating expenses and $3.5 million of reimbursable costs incurred in prior periods. Assume the prior costs not yet reimbursed were $7 million, including $3 million of unsuccessful exploration costs expensed in a prior period and $4 million of capitalized costs. The current amortization expense would be four-sevenths of the $3.5 million, which calculates to $2 million.

FAS 69 requires disclosure of the E&P company's net proved reserves under production sharing contracts. At issue is whether to disclose such reserves separately under FAS 69, Paragraph 13 or within the table of directly owned reserves. Arguably, for a true production sharing contract for which the E&P company does not directly own the reserves, Paragraph 13 calls for those net reserves to be disclosed separately from net reserves directly owned. However, since (1) the standardized measure is combined, (2) direct reserves must be disclosed for each foreign geographic area in which significant reserves are located (FAS 69, Paragraph 12), and (3) terms of production sharing contracts vary widely, there is little benefit in disclosing production sharing contract reserves in a separate table rather than including such reserves within the reserve amounts disclosed in the main table. In fact, no separate disclosure tables were found in recent annual reports of a judgmental sampling of large oil and gas companies.[86]

SERVICE CONTRACTS

Another type of agreement prevalent in a contractual system is a *service contract*. Service contracts are not as common as PSCs but nonetheless present many accounting challenges. Service contracts are generally classified as being either *nonrisked service contracts* or *risked service contracts*. Nonrisked service contracts are typified by arrangements wherein the E&P company agrees to provide "services" in the form of exploration, development, and production activities. The government then pays the E&P company a "fee" covering all costs incurred by the company and providing a profit. In other words, the host country bears all risks of exploration and development. Nonrisked service contracts may be used in areas such as the Middle East, where much capital exists but the expertise and technology are lacking. In any case, the fees earned vary widely over various ranges of success. In practice, risked service contracts are more common than nonrisked service contracts.

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[86]Separate disclosure tables were not found in the 1998 annual reports of Chevron, Exxon, Mobil, and Unocal. Chevron disclosed that its proved reserves included reserves under a "risked service agreement" but not for another service agreement (presumably nonrisked) in the same foreign country. Service agreements are described on the next page of this chapter. Unocal footnotes its reserve tables with disclosure of host countries' reserve share included in the tables.

In a risked service contract the E&P company incurs all costs and risks related to exploration, development, and production activities. In return, if production is achieved, the company receives a fee representing recovery of its costs and a profit. The fee is typically based on a sliding scale linked to the level of production achieved. Other terms and features of risked service contracts are similar to those appearing in PSCs. During the past few years risked service agreements have been used in many Latin American countries.

Risked Service Contract Example

Tyler Company enters into a risked service agreement with the government of Colombia. Tyler Company agrees to pay the government a U.S. $1,000,000 signing bonus and bears all of the costs and risks associated with exploration, development, and production. The government agrees to pay Tyler Company an annual fee comprised of the following:

- All operating costs incurred in the current year,
- 1/10th of all unrecovered capital expenditures,
- $0.60 per barrel on production from 0 to 3,000 bbl. per day (bopd),
- $0.80 per barrel on production from 3,001 to 10,000 bopd, and
- $1.00 per barrel on production above 10,000 bopd.

The contract caps the fee or provides for a maximum total fee of $1.25, including operating costs, per barrel times the total number of barrels produced. If the maximum fee is reached and, as a result, there is unrecovered operating or capital expenditures, such costs can be carried forward indefinitely and recovered in future years.

Production begins in the Verde Field in 2002, at which time Tyler Company has spent $5,000,000 on exploration, drilling, and development. Operating expenditures for the year total $1,500,000. Production during 2002 is 3,650,000 barrels or an average of 10,000 barrels per day. Tyler's total fee for 2002 is determined as follows:

Operating cost reimbursement	$1,500,000
Capital cost recovery ($5,000,000/10)	500,000
Production fee (3,000 bbl x 365 days x $.60)	657,000
Production fee (7,000 bbl x 365 days x $.80)	2,044,000
Total fee	$4,701,000

In order to determine whether the actual fee per barrel exceeds the maximum fee, the following computation is required:

$4,701,000/3,650,000 bbl = $1.288 per bbl

The $1.288 computed fee per barrel is greater than the maximum of $1.25; therefore, the actual fee paid to Tyler Company is:

$1.25 x 3,650,000 = $4,562,500

The difference between the computed fee and the maximum fee ($4,701,000 - $4,562,500 = $138,500) is to be treated as unrecovered capital costs and carried forward.

Tyler Company must pay the government of Colombia income taxes on its local operations, thus decreasing Tyler Company's share and increasing the government's share of profit.

Accounting for risked service contract fees and costs could be similar to that for a production sharing contract. The service provider in a nonrisked service contract would not appear to be engaged in oil and gas producing activity.

COMPARISON OF SHARING ARRANGEMENTS

Figure 25-2 presents an illustration comparing the various sharing arrangements previously discussed.

Figure 25-3: Illustration of Sharing Arrangements

The following example compares four basic forms of sharing arrangements for the exploration and development of a given area of interest. The following are the projected costs and revenue for each sharing arrangement (in millions):

	Total for Venture	Concession (Company's Share)	50% Joint Venture Arrangement (Company's Share)	Service Contract (Company's Share)	Production Sharing Contract (Company's Share)
COSTS					
Bonus to host country	$ 10	$ 10	$ 10	$ 10	$ 10
G&G studies	10	10	5	10	10
Exploration wells:					
Dry	40	40	20	40	40
Productive	20	20	10	20	20
Development costs	120	120	60	120	120
Indirect infrastructure costs	10	10	10	10	10
Total pre-production costs	$ 210	$ 210	$115	$210	$210
Cost subject to cost recovery				$200	$200
REVENUE					
Revenue sharing arrangements		WI, net of royalty	WI, net of royalty	180% of cost	Cost recovery
Revenue share for 20 years		80%			
Revenue share			40%		
Share of cost production				90%	90%
Share of profit production for 20 years					25%
Share of first $222 million in revenue	$ 222	$ 178	$ 89	$200	$200
Share of subsequent revenue for 20 years	2,000	1,600	800	160	500
Share of revenues after 20 years	1,000	0	400	0	0
Total revenues	$3,222	$1,778	$1,289	$360	$700
Examples:					
Year 1 of production					
Revenue	$ 100	$ 80	$ 40	$ 90	$ 90
Operating costs	(10)	(10)	(5)	(10)	(10)
DD&A*		(7)	(3)	(40)	(21)
Income before taxes		$ 63	$ 32	$ 40	$ 59
Year 2 of production					
Revenue	$200	$160	$ 80	$180	$130
Operating costs	(20)	(20)	(10)	(20)	(20)
DD&A*		(14)	(6)	(80)	(30)
Income before taxes		$126	$ 64	$ 80	$ 80

*Assuming for simplicity that successful efforts capitalized costs are amortized over assumed total current and future revenues.

OTHER ACCOUNTING MATTERS UNIQUE TO INTERNATIONAL OPERATIONS

GENERAL

Today there is no single, recognized set of international accounting standards for the oil and gas industry. The International Accounting Standards Committee (IASC) plans to issue such a standard that will apply to all extractive industries sometime during 2002. Current international oil and gas accounting practices and procedures have largely evolved from the terms of underlying exploration and development contracts. However, as discussed in previous chapters, financial reporting policies should follow the substance of transactions, not necessarily their legal form. Accordingly, there is an inherent conflict in designing accounting practices and procedures which follow the underlying contract's legal form as opposed to its economic substance.

As stated earlier, accounting for foreign operations may require keeping two sets of accounting records: one to comply with host country requirements and one for U.S. reporting purposes. Regardless of whether one or more sets of books are necessary, the accounting system must be designed to capture information required for both countries' reporting requirements. This idea sounds superficial until one considers that the term and concept of intangible drilling costs (IDC) are not recognizable to some foreign nationals. Some countries capitalize interest; others do not. In some countries the concept of depreciation and amortization is foreign in that the tax laws allow them to expense everything as incurred. Some operations require reporting to be done in more than two currencies. In any case, the accounting, reporting, and information system problems can be very complex.

LIFTING IMBALANCES

As in the U.S., accounting for lifting imbalances can be difficult. The lifting imbalance is the difference between volume actually lifted and volume the company is entitled to lift. The operator should notify all parties of the actual detail for all the variables (shown below) used initially to calculate entitlements:

- Total production,
- Actual royalty production,

- Actual cost recovery production,
- Actual investment credit production, and
- Actual profit production.

Lifting imbalances may be settled in cash or in kind. The operator should provide the details of the overlift or underlift position of each party and the final overlift or underlift position of each party in relation to other parties. Each party that is overlifted at the end of the year, or other time period as specified in the arrangement, should notify the operator and other parties of its intended method of settlement.

In order to make an informed decision regarding the settlement of lifting imbalances, a thorough understanding of the available options is crucial. Pricing assumptions have to be made for the relevant time period, and calculations must be performed. Once the results of the calculations have been carefully analyzed, a decision can be reached. Notification should be given to the operator on a timely basis in order to execute a proper election.

RESERVES

The question sometimes arises about when proved reserves should be recognized. The host country's declaration that the field is commercial may be desired before the reserve estimator judges the reserves to be proved.

FAS 69, Paragraph 17 (Oi5.167) requires disclosure of host country requirements that restrict reserve disclosures or include unproved reserves. For instance, in certain countries year-end reserves are priced at average year prices, as opposed to year-end prices that must be used under the SEC definition of proved reserves. Financial statement disclosure of which definition is used may be appropriate.

For some countries, oil reserve quantities are estimated and reported in metric tons which must be converted to barrels for financial reporting in the U.S.

FULL COST

In the early stages of exploration in a new foreign country, the E&P company may drill one or more dry holes and have no proved reserves for that country. Generally, the company would defer the dry hole costs when definitive plans exist for further exploration in that country. That is the practice for three of four full cost companies addressing the issue in the

1999 PricewaterhouseCoopers Survey of U.S. Petroleum Accounting Practices. The fourth company expensed the dry hole costs.

The SEC staff has indicated that it would be inappropriate to establish any minimum *safe harbor* period and that any evaluation of the propriety of costs deferred should be based on specific facts and circumstances. The staff discussions have indicated that if the results of the activities (such as stratigraphic wells and seismic studies) were favorable, then the staff would likely permit extended deferrals. If early results were less encouraging, a more conservative approach would be expected. The staff has stated that management has the responsibility for justifying cost deferred in a new cost center. The staff has also emphasized the existence of disclosure requirements, including an aging of excluded costs and a narrative discussion of the properties or projects involved.

MISCELLANEOUS ISSUES

INTERNATIONAL ACCOUNTING CONTROLS

The Foreign Corrupt Practices Act of 1977 (FCPA) requires certain companies to establish and maintain internal accounting control systems that satisfy certain objectives. The FCPA has two parts: one deals with specific acts and penalties associated with certain corrupt practices, the second with standards relating to internal accounting controls (i.e., internal control procedures).

The FCPA prohibits any domestic company—or its officers, directors, employees, agents, or stockholders—from paying or offering to pay a foreign official to obtain, retain, or direct business to any person. Specifically, the law prohibits payments to foreign officials, political parties, and candidates for the purpose of obtaining or retaining business by influencing any act or decision of foreign parties in their official capacity, or by inducing such foreign parties to use their influence with a foreign government to sway any act or decision of such government. This section of the FCPA applies to virtually all U.S. businesses, and noncompliance with its provision can result in significant fines for corporations and individuals who willfully participate in the bribery of a foreign official. Violators may also be subject to imprisonment.

The section of the FCPA addressing internal accounting controls imposes additional legal obligations on companies subject to provisions of the Securities Exchange Act of 1934. Failure by such companies to maintain appropriate books and records and internal accounting controls violates the Act. In addition, the FCPA imposes criminal liability for failing to comply with the internal accounting control provisions if an individual knowingly circumvents, knowingly fails to implement a system of internal accounting controls, or knowingly falsifies any books, records, or accounts.

The primary intent of the FCPA is to prevent corrupt payments to foreign officials, and it requires accurate books and records and internal accounting controls to be maintained to help accomplish that objective. The FCPA necessitates management's direct involvement in designing and maintaining the internal control structure.

TRANSFER PRICING

If a U.S. company's Latin American subsidiary sells produced crude oil to the U.S. parent at a transfer price of $30 per barrel when the market price is $28 per barrel, then $2 per barrel of profit is shifted from the U.S. parent to the foreign subsidiary. To prevent such shifts of income, the Internal Revenue Service imposes significant nondeductible penalties if transfer prices are determined not to be at arm's length. To avoid the risk of such penalties, the company must

- Determine a method to support transfer pricing at arm's length,
- Maintain documentation supporting arm's-length transfer pricing, and
- Provide this documentation in a timely manner to the IRS if requested.

HOST COUNTRY AUDITORS

Host government's auditors will periodically audit the transactions and the company's books and records associated with an E&P venture's operations. Depending on the nature of their audit and the location of supporting invoices and other documentation, the host government's auditors may request to conduct their activities in the company's home office location as opposed to the field location. These auditors are generally highly skeptical of the company's actions and are interested in determining what types of *profits* the company is earning in the venture's activities.

A number of items are typically discussed and negotiated between the host country and the company as a result of these audits:

- **Overhead.** For what types of home office overhead is the company being reimbursed? Are such costs reasonable, supportable, and directly related to the venture's operations? What is the basis of the company's overhead allocation to the venture? Are such allocations consistent between years and consistently applied to the company's other ventures?
- **Technical Staff.** What is the nature of work charged for home office technical staff? How are the technical staff billing rates determined? What is the procedure for technical staff to account for time spent on each venture?
- **Costs in excess of AFEs.** What is the nature of costs incurred over the approved AFE amount? Are these excess costs subject to cost recovery?

The submission of audit findings and their subsequent resolution is generally a lengthy and time-consuming process that normally involves numerous levels of management.

DISMANTLEMENT, RESTORATION, AND ABANDONMENT OBLIGATIONS

With the petroleum industry's strong environmental concerns, the dismantlement, restoration, and abandonment of producing fields become increasingly important. Environmental concerns are complex and depend in large measure on local environmental standards. Typically, the petroleum industry has sought to insulate itself from the impact of these obligations through the concept of host country ownership of the resource and the reversionary production rights established in favor of the host country. Under most arrangements, it is probable that economic production life will remain with and revert to the host country. With the transfer of the producing asset goes the obligation to abandon the field. Often the contract provides that title to the fixed assets (wells, storage facilities, and pipelines) vests in the host country (either at inception or payout), and with the title goes the abandonment obligation.

If the host country requires environmental impact studies and the restoration of the area to its preexisting condition, the standard is clear. The extent of the obligation and costs associated with abandonment can be forecast. The total costs and plans for abandonment can be incorporated into the development plan.

Some PSCs require the companies to put money into a sinking fund to be used in the future to pay for abandonment and reclamation. If these sinking fund payments are considered to be recoverable costs (reducing profit oil), the government is actually sharing in dismantlement and reclamation costs to the extent the government shares in the corresponding reduction in profit oil. In other words, assuming the companies fully recover all of their costs, the companies deposit money into a fund and, ultimately, get to cost recover those deposits from future production. Since the companies are allowed cost recovery on the deposits, the companies' net cost is zero, and money in the fund is available to pay for dismantlement and reclamation as the costs are actually incurred.

U.S. GAAP accounting for dismantlement, restoration, and abandonment obligations is the same whether for a U.S. property or a foreign property. See Chapter Twenty.

As has been repeatedly emphasized, petroleum exploration is, by its very nature, risky and uncertain. Since most exploration ventures are unsuccessful, companies should carefully assess the impact of terminating their exploration efforts in a host country at certain well-defined times. One factor to consider is whether the company will have the ability to withdraw without penalty after fulfilling certain benchmark work obligations.

Chapter Twenty-Six

BASIC E&P INCOME TAX RULES

This chapter presents an overview of U.S. federal income tax laws and regulations that are unique to petroleum exploration and production. In seeking to comply with tax laws and regulations, E&P companies should not rely solely on this chapter but should also obtain outside professional advice and refer directly to current tax laws and regulations.

Determining an E&P company's federal income taxes requires accounting that differs in many ways from GAAP accounting. For example, under income tax laws in effect on December 31, 1999:

1. G&G costs leading to acquisition of a property must be capitalized as property acquisition costs;
2. Capitalized unproved property costs are not reduced for impairment but are written-off when the property is found to be worthless;
3. All, or substantially all, intangible costs of successful wells may be deducted (expensed) when incurred;
4. Costs of development dry holes, including abandoned tangible assets such as casing, may be deducted when dry hole status is determined;
5. Deductions may include *percentage depletion* that bears no direct relationship to the actual costs incurred; and
6. Some production payment obligations are viewed as debt for income tax accounting and as deferred revenue for GAAP accounting.

The U.S. Internal Revenue Code provides certain tax incentives to encourage exploration and production in the United States. Conversely, the code also imposes many complex restrictions on the use of these tax incentives in the form of an alternative minimum tax system and, in certain cases, limitations on the use of losses by investors in the industry.

Countervailing tax policy considerations as well as the unique nature of the oil and gas industry combine to make U.S. taxation of oil and gas a complex and highly specialized area.

OVERVIEW OF U.S. TAX ON OIL AND GAS

The United States currently levies no special federal tax on income from oil and gas production, such as the U.K. petroleum revenue tax or the Australian petroleum resource rent tax. Instead, income from oil and gas activity is taxed within the parameters of the regular income tax system.

The U.S. tax laws provide many special rules for determining the appropriate amount of income and deductions to be included in the calculation of taxable income from oil and gas exploration and production. To properly apply these rules, it is essential to understand certain fundamental oil and gas tax concepts such as oil and gas property, mineral interest, and economic interest. This chapter introduces these fundamental concepts and special tax rules.

The federal tax system is complicated by the existence of a second, parallel system of income taxation that generates what is called the alternative minimum tax (AMT). A taxpayer's federal income tax liability is the higher of the regular income tax or the AMT. The AMT has its own rules for determining taxable income and was, as its name suggests, enacted to ensure that all profitable businesses pay some tax. The AMT is a function of the regular taxable income adjusted to an AMT income.

The AMT is particularly relevant to the oil and gas industry because many tax deductions under the regular tax rules are added back, adjusted, or recalculated to calculate the AMT for an E&P company.

Many states and some cities levy their own income taxes. In most cases, these state and local taxes are imposed on federal taxable income, with adjustments.

Local jurisdictions often impose other taxes, including real and personal property taxes and sales taxes, and virtually every state with oil and gas production imposes a tax (referred to as a production tax or severance tax) on the value or quantity of oil and gas produced in the state.

THE OIL AND GAS PROPERTY

A clear understanding of the concept of *property* is important because it is the cornerstone of U.S. oil and gas taxation. Almost all tax accounting for oil and gas activity is done on a property-by-property basis, e.g., computing depletion deductions, intangible drilling cost deductions, and gain or loss on property disposition. The determination of whether a write-off for worthlessness may be taken is also made on a property-by-property basis.

In spite of the importance of the property concept, U.S. tax law says very little about defining property:

> The term property means each separate interest owned by the taxpayer in each mineral deposit in each separate tract or parcel of land.[87]

For purposes of this definition, the term interest means an economic interest. Thus, an oil and gas property constitutes (1) each separate economic interest owned by a taxpayer in (2) each separate mineral deposit in (3) each separate tract or parcel or land.

In general, the tax authorities have interpreted this brief definition to mean that each mineral interest (e.g., royalty interest, working interest, overriding royalty interest, production payment, or net profits interest) is a separate property unless the same types of interests were acquired at the same time, from the same assignor, and in geographically contiguous tracts of land. If a taxpayer holds more than one operating interest in the same tract of land, the taxpayer must combine the interests and treat them as a single property unless an election is made to treat them as separate properties. Two or more separate nonoperating interests in the same tract of land may be combined, with the permission of the Internal Revenue Service, upon demonstration by the taxpayer that the principal purpose of the combination is not tax avoidance. A nonoperating interest cannot be combined with an operating interest.

ECONOMIC INTEREST

The determination of whether a property interest is an *economic interest* is important, because only the owner of an economic interest may deduct depletion from the oil and gas income generated by a producing property. U.S. tax regulations provide the following description of an economic interest:

> An economic interest is possessed in every case in which the taxpayer has acquired by investment any interest in minerals in place . . . and secures, by any form of legal relationship, income derived from the

[87] Internal Revenue Code Section 614(a).

> extraction of the mineral . . . to which he must look for a return of his capital.[88]

A large body of case law has developed around this description to clarify the concept. For tax purposes, an economic interest generally must meet the following four requirements:

1. The interest must represent a capital interest in the minerals in place;
2. The interest must provide the right to share in the minerals produced or the right to the proceeds from their sale;
3. The interest holder must look solely to the proceeds from extraction for a return on investment; and
4. The interest must be held as a matter of legal right.

The following common property interests are economic interests, the holders of which are eligible to claim depletion: a royalty interest, a working interest, an overriding royalty interest, and a net profits interest. A production payment may be treated as an economic interest for tax purposes only if the production payment is carved out of a property and assigned to a party in exchange for an agreement to develop the property or if the production payment is retained by the lessor in a leasing transaction. Otherwise, the production payment is viewed as a right to repayment of a loan.

LEASEHOLD

The acquisition cost of an oil and gas property is commonly referred to as leasehold basis, depletable basis, or leasehold. Leasehold reflects all the costs of acquisition that, for tax purposes, must be capitalized. Among the costs capitalized into leasehold are the following:

- Geological and geophysical costs allocable to the property;
- Purchase price allocable to the mineral interest in the case of an acquisition of a fee interest;
- Lease bonus paid in the case of a leasing transaction;

[88] Treasury Regulations Section 1.611-1(b).

- Finders' fees, commissions, legal fees, and other professional fees incurred in the acquisition; and
- Delay rentals that have been capitalized.

If the oil and gas property is productive, the capitalized costs of the leasehold are recovered through depletion deductions over the producing life of the property. If the property is determined to be worthless as a result of, for example, abandonment, termination of the lease, cessation of production, or the drilling of an unproductive well (a dry hole), then capitalized leasehold costs must be deducted from income in the year the property is deemed worthless.

The timing of the deduction for worthlessness is often an issue, so it is important that the property holder can point to a specific, identifiable event to fix the time of worthlessness. The actions of the property holder are important in determining whether the property should be deemed worthless for tax purposes. For example, even if a dry hole was drilled on a lease, the lease could not be deemed worthless if later a delay rental is paid or additional exploration and development work is undertaken.

GEOLOGICAL AND GEOPHYSICAL COSTS

In general, G&G costs that lead to the acquisition of a property must be capitalized as part of the cost of the property. Costs not leading to the potential acquisition of a property may be deducted in the year paid or incurred. G&G costs typically are incurred in two distinct phases. Initial costs are incurred in a broad reconnaissance survey of a large area to determine which specific areas within the larger project area warrant closer study. All G&G costs incurred in this phase are allocated equally among the specifically identified areas—so-called *areas of interest*— without regard to their relative sizes. If only one area of interest is identified, all costs are allocated to that area. If no area of interest is identified, all of the G&G costs incurred in the initial survey are deducted in the year paid or incurred.

Once the areas of interest have been identified, detailed surveys are conducted. The costs of a detailed survey are allocated to the specific area of interest upon which the survey was conducted.

If individual properties within the area of interest are leased, the total of geological and geophysical costs related to that area of interest, including the costs of the detailed survey as well as an allocable portion of reconnaissance survey costs, are allocated to the properties acquired on an acreage basis.

If no leases are acquired within the areas of interest, then all costs incurred in or allocated to those areas are deducted in the year in which the areas are abandoned.

DEVELOPMENT COSTS

For tax purposes, costs incurred in developing an oil and gas property are divided into two categories:

1. Tangible equipment costs and
2. Intangible drilling and development costs.

Because the tax treatments of these costs differ so significantly, it is important that they be properly classified.

TANGIBLE EQUIPMENT COSTS

Tangible equipment costs are those incurred to purchase equipment of a type ordinarily considered to have some salvage value. Tangible equipment includes surface and production casing, wellhead equipment, tanks, pumps, separators, and other machinery.

Tangible equipment costs must be capitalized and recovered over the life of the equipment through depreciation. The Internal Revenue Service has published guidelines defining the useful life of all types of tangible equipment for depreciation purposes. Under current law, most tangible production equipment has a depreciable life of seven years. Lease and well equipment also may be depreciated under a units-of-production method. This method is essentially the same as a cost depletion rate and requires no adjustment for the AMT. Certain property located on current or former Indian reservation property may be depreciated using a depreciation life that is significantly shorter than the regular depreciation lives. For this purpose, current and former Indian reservation property includes most property located in Oklahoma.

INTANGIBLE DRILLING COSTS

Intangible drilling costs (IDC) are costs that have no salvage value and that are incidental to and necessary for the drilling of wells or the preparation of wells for oil and gas production. Intangible drilling costs are usually the single largest category of expense associated with drilling a well.

Examples of IDC include all amounts paid for labor, fuel, repairs, hauling, rents, and supplies used in the following activities:

- Drilling a well;
- Clearing and draining ground, road-making, and surveying ground in preparation for drilling a well; and
- Assembling derricks, tanks, pipelines, and other physical structures necessary for drilling and preparation of a well for oil and gas production.

IDC ELECTION

A taxpayer holding an operating right to a U.S. oil and gas property must elect, in the first year in which the taxpayer pays or incurs intangible drilling costs, whether to capitalize IDC or deduct it currently for wells drilled in the United States. In most cases, an election is made to deduct IDC.

Because of the binding nature of the election to capitalize IDC, it is important to consider the options carefully and make the election properly. The election to deduct IDC currently may be made simply by deducting the costs on the tax return for the first year in which such costs are paid or incurred. Those who fail to deduct such costs on the return for the first year in which they are paid or incurred will be deemed to have elected to capitalize IDC.

Although no formal election is necessary to deduct IDC, the significance of the election is such that the taxpayer typically attaches a statement to the income tax return for the year in which such costs are first incurred, clearly stating this intention.

Taxpayers electing initially to capitalize IDC must allocate the capitalized costs to leasehold and recover them through depletion or, to the extent the costs are identified with the installation of tangible equipment, allocate the costs to the equipment and recover them through depreciation.

Taxpayers electing initially to deduct IDC currently have an additional annual election to capitalize all or a portion of the IDC incurred in that tax year. The capitalized portion is amortized ratably over a 60-month period beginning in the month the costs are paid or incurred. IDC capitalized under this option will not be treated as a tax preference item for alternative minimum tax purposes.

Integrated oil and gas companies may deduct only 70 percent of the IDC at the time those costs are incurred. The remaining 30 percent must be capitalized and amortized ratably over a 60-month period beginning in the month the costs are paid or incurred.

IDC for wells located outside the U.S. may not be deducted currently. Such costs may, at the election of the taxpayer, be included in the adjusted basis of the oil and gas property for purposes of computing depletion or be amortized over a 120-month period.

DRY HOLE COST

If a well is drilled and found to be a dry hole (i.e., it does not produce oil or gas in commercially marketable quantities), the development costs associated with the well should be deducted as dry hole costs. Leasehold costs may or may not be currently deductible, depending on whether the lease is deemed worthless.

GUIDANCE ON WELL COST CLASSIFICATION

Proper classification of well costs as IDC or tangible costs is an important issue for an E&P company, especially joint venture operators. They are required to classify the venture's well costs when billing joint venture partners for their share of costs.

IRS Regulation §1.612-4 describes some items *not* included in the IDC category:

(c) *Non-optional items distinguished.*

(1) Capital items: The option with respect to intangible drilling and development costs does not apply to expenditures by which the taxpayer acquires tangible property ordinarily considered as having a salvage value. Examples of such items are the costs of the actual materials in those structures which are constructed in the wells and on the property, and the cost of drilling tools, pipe, casing, tubing, tanks, engines, boilers, machines, etc. The option does not apply to any expenditures for wages, fuel, repairs, hauling, supplies, etc., in

> connection with equipment, facilities, or structures not incident to or necessary for the drilling of wells, such as structures for storing or treating oil or gas. These are capital items and are returnable through depreciation.
>
> (2) Expense items: Expenditures which must be charged off as expense, regardless of the option provided by this section, are those for labor, fuel, repairs, hauling, supplies, etc., in connection with the operation of the wells and of other facilities on the property for the production of oil and gas.

Revenue Ruling 70-414 further explains which items are treated as IDC and which are not. A portion of this ruling follows:

> [IDC] excludes expenditures incurred in installing production facilities. The items thus excluded consist of expenditures relating to the installation of equipment such as pumping equipment, flow lines, separators, storage tanks, treating equipment, and salt water disposal equipment. Equipment of a character that is ordinarily considered as having a salvage value, whether it consists of production facilities or equipment necessary for the completion of a well, including cost of casing in a well (even though cemented in the well to such an extent that it has no net salvage value), is a depreciable item, the cost of which may be recovered only through the depreciation allowance. *Harper Oil Company v. U.S.*, 425 F. 2d 1335 (10th Cir. 1979), 70-1 USTC 9330. A producing well is completed when the casing, including the so-called *Christmas tree*, has been installed.

It is held that the cost of the installation of the items listed below is *not* subject to the IDC expense option provided for in Reg. §1.612.4(a):

1. Oil well pumps (upon initial completion of the well), including the necessary housing structures;
2. Oil well pumps (after the well has flowed for a time), including the necessary housing structures;
3. Oil well separators, including the necessary housing structures;
4. Pipelines from the wellhead to oil storage tanks on the producing lease;
5. Oil storage tanks on the producing lease;
6. Salt water disposal equipment, including any necessary pipelines;
7. Pipelines from the mouth of a gas well to the first point of control, such as a common carrier pipeline, natural gasoline plant, or carbon black plant;

8. Recycling equipment, including any necessary pipelines; and
9. Pipelines from oil storage tanks on the producing leasehold to a common carrier pipeline.

A list of common IDC items is given below. The list is not intended to be exhaustive, but it does include a number of examples in each category.

1. *Cost before drilling begins*
   (a) Work performed by the geologist to determine the exact location of the drill site (not G&G work to select leases);
   (b) Bulldozer costs for clearing well site, digging slush pits, building roads, and survey costs involved in staking well location;
   (c) Cost of pads (gravel, etc.) for drilling rig;
   (d) Cost of bridges;
   (e) Laying flow lines for water to be used in drilling;
   (f) Installation of tanks for water and fuel for drilling purposes;
   (g) Moving and erecting drilling rig (if company owned); and
   (g) Construction of racks for drill pipe and other tubular goods to be used in the drilling process.

2. *Costs during drilling process*
   (a) If a contractor drills the well, the contractor's bill will constitute the majority of the IDC costs in this category. The drilling mud and possibly other items may represent an additional charge to the operator.
   (b) If the well is drilled by the operator's rig, then the wages paid the crew, drilling rig maintenance and supplies, depreciation on the rig, mud, water, fuel, power, chemicals, bits, reamers, and company overhead related to the operation of the rig will represent IDC charges.

3. *Completion costs*
   (a) Drill stem tests, well logging, and other testing such as cores and side wall sampling;
   (b) Perforating, cementing, fracturing, acidizing; and
   (c) Transportation and installation of subsurface equipment.

4. *Charges after well is completed*
   (a) Removing drilling equipment from the location (if operator owned),
   (b) Restoring the land by filling slush pits and grading the area,
   (c) Surface damages, and
   (d) Plugging and abandonment costs (if the well is a dry hole).

The election to deduct intangible drilling and development costs for federal income tax purposes extends only to those intangible costs incurred in drilling the well and in installing equipment in the well up through the point that valves are installed at the wellhead to control production. Thus, labor costs and other intangible costs to install flow lines, treating equipment, and storage tanks are not subject to the IDC election for tax purposes, but are treated as part of the cost of tangible equipment. Nevertheless, other intangible costs incurred after the wellhead is installed but not related to installing equipment (e.g., removal of the rig from the drilling site and restoring the location) are treated as IDC for tax purposes.

The tax laws also generally govern the definition of tangible costs. Tangible asset costs include all costs of the physical assets themselves (such as casing, pumps, production, tubing, flow lines, separators, etc.), along with the installation costs of surface equipment. In accounting theory, the costs of installing all equipment, including such subsurface equipment as casing, should be treated as part of the cost of tangible assets, but because most companies elect to expense IDC for income tax purposes, and because the tax laws include installation costs of equipment (up through the point that control valves are installed) in the election, such costs are generally treated as intangible costs. For financial accounting purposes, this is not an important distinction, because intangible costs are treated in the same way as tangible costs.

DEPLETION

Producing oil and gas properties are, by their nature, wasting assets. U.S. tax law recognizes the wasting nature of the asset by providing a depletion deduction in limited cases to the owners of the economic interest in the asset.

There are two methods for computing the depletion allowance: cost depletion and percentage (or statutory) depletion.

To calculate cost depletion for each property, a cost factor is determined by dividing units of production from the property during the year by total estimated recoverable reserves (i.e., proved reserves) attributable to the property at the beginning of the year. This factor is multiplied by net leasehold costs of the property to arrive at the cost depletion amount.

Percentage depletion, in contrast, simply provides for a deduction of a specified percentage (currently 15 percent for nonmarginal well production) of gross revenue from the property, limited to a percentage of the net income from the property (currently 100 percent). It is not generally available to integrated oil and gas companies' U.S. production. The percentage depletion deduction is limited to U.S. production of 1,000 equivalent barrels of oil per day by an independent producer or a royalty owner and cannot exceed 65 percent of a taxpayer's total taxable income (before the deduction for percentage depletion) for the year. Percentage depletion deductions disallowed as a result of the 65 percent of taxable income limitation may be allowed in succeeding taxable years provided the 65 percent of taxable income limitation does not apply. Percentage depletion is not available on foreign production. Those eligible to claim percentage depletion may not elect to use one method or the other (cost depletion or percentage depletion), but must compute depletion using both methods and claim the higher of the two.

Allowable depletion (i.e., the higher of cost or percentage depletion) for each property reduces the taxpayer's basis in the mineral property. Once the taxpayer's basis in the property is reduced to zero, cost depletion can no longer be claimed. Percentage depletion can be claimed, however, for as long as the property continues to produce oil and gas.

A special concession exists for marginal properties in that percentage depletion rates are increased during periods in which the price of oil or gas is deemed insufficient for profitable operations of such properties. Specifically for interests in marginal properties held by independent producers or royalty owners, the percentage depletion rate (15 percent) is increased by one percent for each whole dollar that the *reference price* for crude oil in the immediately preceding calendar year is less than $20 per barrel. The *reference price* is a defined amount based on the average wellhead price in the U.S. and is published by the IRS each calendar year. For 1999, the marginal depletion rate is 24 percent. The maximum depletion rate under this concession is 25 percent. For this purpose, a marginal property includes (1) oil and gas produced from a domestic stripper well property (generally 15 barrel equivalent or less of production per day per well) and (2) oil from a domestic property which is substantially all *heavy* (gravity of 20 degrees API or less) oil. In addition, the 100 percent of net income limitation is suspended for marginal properties for any taxable year beginning after December 31, 1997 and before January 1, 2002

SAMPLE DEPLETION CALCULATION

Operator O acquired a mineral lease and began drilling in January 1999. The well was successful and production began in April. Over the remainder of the year the property produced 40,000 barrels (bbls) of oil that were sold for total gross revenue, after royalties, of $577,500. Drilling and production expenses on the property for the year amounted to $492,500, leaving $85,000 of taxable income before deducting depletion. At December 31, 1999, the property had a leasehold basis of $300,000 before depletion for the current year. Mineral reserves at December 31, 1999, totaled 360,000 bbls. O's taxable income from all sources for the year, before depletion, was $120,000. The mineral interest is a U.S. property and Operator O is an independent producer. Allowable depletion is computed as follows:

Cost Depletion:

$$\frac{\text{1999 Production}}{\text{Beginning of year reserves}} \times \text{Leasehold basis at end of year}$$

$$\frac{40{,}000}{360{,}000 + 40{,}000} \times \$300{,}000 = \underline{\underline{\$30{,}000}}$$

Percentage Depletion:

Gross revenue	$577,500
x Statutory rate	x 15%
Percentage depletion before limitation	$ 86,625
Limited to pre-depletion net income from the property	$ 85,000
Taxable income (all sources) before depletion	$120,000
Limitation on taxable income (multiplied at 65%)	x 65%
Taxable income limitation	$ 78,000
Percentage depletion after limitations	$ 78,000

Allowable depletion (greater of $30,000 cost depletion or $78,000 percentage depletion)	$ 78,000
Leasehold basis at beginning of next year ($300,000 - $85,000)	$215,000
Percentage depletion carryover to succeeding years ($85,000 - $78,000)	$7,000

SHARING ARRANGEMENTS

To reduce the costs and risks to one party in developing an oil and gas property, it is not unusual for two or more parties to join together in a sharing arrangement to explore jointly for oil and gas. In general, a sharing arrangement is a transaction in which one party contributes cash, property, services, or other consideration to the exploration and development effort in exchange for an interest in the mineral property. In a common type of sharing arrangement, known as a *farm out*, the owner of an operating interest assigns all or a portion of the operating interest to another party in return for the assignee's assumption of all or a portion of the costs of developing the property.

Sharing arrangements can take many forms, including the following:

- Drilling a well in exchange for the entire operating interest (the assignor may or may not retain a nonoperating interest);
- Drilling a well in exchange for a portion of the operating interest;
- Drilling a well in exchange for a nonoperating interest;
- Pledging cash to the development of a property in exchange for an operating or nonoperating interest in that property; or
- A mixed sharing arrangement in which cash or other consideration, as well as development work, is contributed in exchange for an interest in a property.

A simple, unmixed sharing arrangement is a nontaxable transaction. If no consideration passes between the parties other than a contribution to or assumption of an obligation to develop a property, neither party realizes gain or loss from the transaction. This concept is frequently referred to as the *pool-of-capital* doctrine. Other U.S. tax principles generally applicable to sharing arrangements are as follows:

- Only the party that pays and incurs a cost can deduct it for tax purposes.
- Only operating interest owners can deduct IDC and depreciation, and then only to the extent of their fractional share of the operating interest. The fractional share of IDC or equipment costs incurred in excess of the fractional share owned in the operating interest must be capitalized and added to depletable leasehold costs.

For example, assume X agrees with Y to drill and equip a well on Y's undeveloped property, at no cost to Y, in exchange for a 75 percent operating interest. X incurs $100,000 of IDC and $40,000 of equipment costs. X may deduct $75,000 of IDC and depreciate $30,000 as equipment costs. The remaining $25,000 of IDC and the $10,000 of equipment costs must be added to depletable leasehold costs. Y has no right to deduct any of the costs since they were borne entirely by X.

The tax consequences of entering into a *mixed* sharing arrangement are more complex than those encountered in a simple sharing arrangement. In general, the transaction must be divided into two parts, with the pool-of-capital doctrine applied to the development work contribution, and potential tax gain or loss flowing from the contribution of cash or other consideration.

LOSS LIMITATIONS

Investors in the oil and gas industry must consider some very complex provisions of the U.S. tax law designed to limit the use of losses from oil and gas activity to offset income from other unrelated activities. These loss limitation rules fall into two broad categories:

1. *At-risk rules* and
2. *Passive loss* rules.

AT-RISK RULES

Under the at-risk rules, individuals engaged in oil and gas exploration and production may deduct a loss for tax purposes only to the extent they are *at-risk* for such activity at the close of the year. An individual is at risk for the activity to the extent of the cash and adjusted basis of any property that he or she contributed to the activity, plus the amounts borrowed to fund the activity for which the individual is personally liable or for which the individual has pledged property (other than property used in the oil and gas activity) as security for the loan. For purposes of deducting partnership losses, partners in an oil and gas partnership are at risk to the extent of their contributions to the partnership (assuming the amounts contributed are at risk at the individual level) and generally to the extent of loans to the partnership for which the partners could be held personally liable.

Loss deductions disallowed because of the at-risk limitation are not permanently lost. Disallowed losses may be carried forward indefinitely and deducted in succeeding tax years when the at-risk amount with respect to the activity is increased.

The at-risk rules also contain anti-abuse provisions which disregard year-end increases to the at-risk amount when the amount is decreased immediately after year end, unless it can be demonstrated that the transactions were undertaken for valid business purposes and not merely to avoid the at-risk rules.

PASSIVE LOSS RULES

Enacted in 1986 to deter investment in so-called *tax shelters*, the passive loss rules provide that investors may not use losses or tax credits generated by *passive activities* to offset wage and salary income, business profits from activities in which the investor materially participates, or investment income, such as dividends, interest, or royalties. Instead, passive losses and credits can be used only to offset income from other passive activities.

Disallowed passive losses and credits are not irretrievably lost but are suspended and carried forward to offset passive income in future years. Suspended losses and credits may be used in full in the year in which the passive investment is disposed of in a taxable transaction.

The passive loss rules apply to individuals, estates, trusts, and certain closely held subchapter C corporations. They do not apply directly to a partnership or a subchapter S corporation, but they do apply to a partner's or a subchapter S corporation shareholder's distributive share of passive losses and credits.

In general, a passive activity is any trade or business activity (including oil and gas activity) in which the taxpayer does not materially participate. To meet the material participation standard, a taxpayer must maintain regular, continuous, and substantial participation in the activity. Due to the nature of the oil and gas industry, the passive loss rules do not apply to any investor who holds a working interest in an oil and gas property directly or through an entity that does not limit the investor's legal liability. The working interest exception applies regardless of the investor's level of participation in the activity.

For this purpose, the working interest is solely the interest burdened with the cost of developing the property. Interests created out of the working interest, such as overriding royalties, net profits interests, or production payments, do not qualify for the working interest exception.

ALTERNATIVE MINIMUM TAX

The alternative minimum tax (AMT) was enacted to ensure that all *profitable* business activities, even activities using lawful tax incentives to reduce their regular income tax liabilities, pay some federal income tax. Some form of minimum tax has been in the law since 1969, but it was only after 1986, when the scope of the AMT was broadened significantly, that it became a major issue for taxpayers in general and the oil and gas industry in particular.

The AMT is effectively a separate tax system that runs parallel to the regular federal income tax system. In the computation of AMT, the alternative minimum taxable income (AMTI) is essentially determined by increasing regular taxable income by certain tax preferences and adjustments.

For individuals, AMTI in excess of an exemption amount (which phases out over certain income levels) is subject to a 26 percent tax for AMTI up to $175,000 and a 28 percent tax for AMTI exceeding $175,000. For corporations, AMTI in excess of an exemption amount ($40,000, which also phases out over certain income levels) is taxed at a flat rate of 20 percent.

Up to 90 percent of AMT liability can be offset by foreign tax credits calculated under special AMT rules. AMT paid after 1986 generally may be carried forward indefinitely as a credit against any future regular tax liability in excess of the AMT for that year.

For tax years beginning before January 1, 1993, the AMT was of particular concern to the oil and gas industry because two of the most significant regular tax deductions—intangible drilling costs and percentage depletion—were also considered *add-back* preference items in the determination of AMTI.

This AMT burden has been greatly reduced with the passage of the 1992 Energy Act, which repealed the excess percentage depletion preference entirely and the *excess IDC* preference with some limitations. The repeal of these preference items is limited to non-integrated oil companies and is effective for taxable years beginning after 1992. *Excess ID*C is still considered an *add-back* preference item to the extent that the repeal of the *excess IDC* preference results in a more than 40 percent reduction in a taxpayer's AMTI.

Under the pre-1993 law, IDC was a tax preference to the extent that *excess IDC* exceeded 65 percent of a taxpayer's annual net income from oil and gas. *Excess IDC* is the amount of IDC deducted for tax purposes in excess of the amount which would have been deducted had the IDC been capitalized and deducted ratably over 120 months (beginning with the month in which production from the property began). As stated, this calculation must still be made under new law to determine whether the repeal of the excess IDC preference has resulted in a greater than 40 percent reduction in what would have been AMTI prior to the repeal. The amount of excess IDC, which causes a greater than 40 percent reduction in AMTI, will remain a tax preference in the computation of AMT.

Taxpayers subject to AMT because of the IDC preference may be able to reduce their IDC preference by electing to capitalize all or a portion of IDC incurred in a particular year and to amortize it over five years. Careful analysis is important so that neither too little nor too much IDC is capitalized and the maximum tax benefit is obtained.

Most of the other adjustments required to determine AMTI are not unique to the oil and gas industry but apply to all taxpayers. The adjustments most commonly encountered in the oil and gas industry are the following:

- For purposes of the regular tax computation, tangible assets generally are depreciated using a special accelerated method of cost recovery over relatively short asset lives. For AMT purposes, depreciation must be recalculated by using a less accelerated method generally over longer asset lives (for tax years beginning after 1998, the depreciable life for AMT purposes is the same as the life used for regular tax purposes). This results in a smaller deduction for AMT purposes.

- Gain or loss on the disposition of depreciable tangible equipment must be recomputed using the adjusted basis computed using the AMT depreciation life and method.
- Net operating loss deductions must be recomputed using special AMT rules, generally reducing the deduction.
- In the case of corporations with adjusted current earnings (ACE) in excess of taxable income, the calculation of AMT requires that 75 percent of the excess be included in the calculation of AMTI. ACE is a defined term generally modeled after the concept of U.S. tax earnings and profits.

In tax years beginning after 1997, a small corporation is not subject to the AMT. For this purpose, a corporation with average annual gross receipts for the prior three-year period not exceeding $7,500,000 will generally qualify as a small corporation.

SAMPLE CORPORATE AMT CALCULATION FOR TAXABLE YEARS BEGINNING AFTER 1993

Regular taxable income	$ 50,000
Plus (minus) adjustments:	
Depreciation adjustment	5,500
AMT adjustment to asset disposition	(2,000)
Plus tax preferences:	
Excess IDC	125,000
ACE adjustment	5,000
AMTI if excess IDC preference had not been repealed	183,500
IDC preference adjustment (excess IDC disallowed but not more than 40% of AMTI before the adjustment)	(73,400)
AMTI	110,100
Exemption	(40,000)
AMT base	$ 70,100
AMT ($70,100 x 20%)	$ 14,020
Regular tax ($50,000 x 15% applicable corp. tax rate)	$ 7,500
Tax liability (greater of AMT or regular tax)	$ 14,020

FORMS OF ORGANIZATION

Because of the costs and risks associated with exploring for and producing oil and gas, it is not unusual for two or more parties to join together in a common effort to locate and develop oil and gas prospects. These joint efforts can take a variety of legal forms. The most common forms of organization in the oil and gas industry are joint ventures, partnerships, corporations, and certain hybrid entities, such as S corporations and limited liability companies, which combine the legal and tax characteristics of partnerships and corporations.

JOINT VENTURE

It is quite common in the United States for working interest owners in a property to combine efforts to develop a property. Their respective rights and obligations are spelled out in two documents generally referred to as a *joint venture agreement* and a *joint operating agreement*, respectively, as explained in Chapter Ten. Under a typical joint operating agreement, one working interest owner is designated as operator of the joint venture whereas the others assume the role of nonoperators.

An important decision for the joint venture participants is whether they wish to be treated as a partnership for tax purposes or whether they wish to elect out of the partnership tax provisions (most elect out). If the participants meet the requirements and elect to be excluded from the partnership provisions, there is no entity-level tax accounting for revenue or expenses. Instead, participants independently report their share of revenue and expenses for tax purposes. In addition, each participant is free to make an election to expense or capitalize intangible drilling costs.

Joint venture participants may elect to be excluded from the partnership provisions only if the following three conditions are met:

1. Each participant owns an interest in the oil and gas property as co-owners, either in fee or under a lease granting exclusive operating rights;
2. Each participant reserves the right to take in kind or dispose of their shares of production; and
3. The participants do not jointly sell the oil and gas produced, although each may delegate to one of the participants the right to sell his or her share for a period not to exceed one year. This right can be renewed each year.

PARTNERSHIP

A partnership is a separate entity for tax and legal purposes. In contrast to the joint venture, there is an accounting for revenue and expenses at the entity level. A partnership files a tax return but pays no entity-level income tax. Instead, the partnership is treated as a conduit for tax purposes, and the individual partners account for their allocable shares of net income or loss and for their shares of credits.

There are two forms of partnership: general partnership and limited partnership. In a general partnership, all individual partners have unlimited personal liability with respect to the legal obligations of the partnership. A limited partnership is comprised of one or more general partners with unlimited personal liability and one or more classes of *limited partners*. In general, the personal liability of a limited partner does not exceed that partner's contributed capital. Because of the relatively high risks involved in oil and gas exploration and production, the limited partnership is a common form of organization, particularly when operations are being funded by outside investors. It should be noted that the investors are often subject to passive loss rules if the form of entity limits an investor's legal liability (see prior discussion).

Many of the important oil and gas elections are made by the partnership rather than the individual partners and are binding on all the partners. For example, the partnership elects to capitalize or expense intangible drilling costs, and it determines whether oil and gas properties will be combined or remain separate for tax purposes. Frequently, a partnership is used to make special allocations of deductible items where one party contributes a disproportionate amount of the costs. Although most income and deduction items are accounted for at the entity level, depletion can be calculated only at the partner level. It is incumbent upon the partnership to provide the partners with enough information to calculate depletion deductions.

CORPORATION

A corporation is a separate legal entity organized under state law that offers its shareholders legal liability that is limited to their investment in the corporation. A corporation generally files its own income tax return and pays federal and state taxes on its net income. Profits are distributed to shareholders in the form of dividends, which are subject to tax at the shareholder level. Thus, the price paid for the limited liability of a corporation is two levels of tax on its distributed profit.

S CORPORATION

An S corporation is a hybrid entity that combines the legal characteristics of a corporation with many of the tax characteristics of a partnership. For all purposes other than federal income tax, an S corporation is like any other corporation. It is incorporated under state law and offers its shareholders limited legal liability. For federal income tax purposes though, an S corporation is a conduit entity that pays no income tax. Like a partnership, items of income, loss, and credit flow through directly to the shareholders free of an entity-level tax, and like an oil and gas partnership, the crucial elections regarding the treatment of intangible drilling costs and the election to aggregate or separate oil and gas properties, are made at the entity level.

Because of the perceived tax advantages of the S corporation, eligibility is strictly limited. To be granted S corporation status, a corporation must file an election statement subject to the approval of the Internal Revenue Service and meet the following five requirements:

1. The corporation must be a domestic corporation that is not a member of an affiliated group;
2. The corporation may have no more than 70 shareholders;
3. The shareholders may be only individuals, estates, or certain qualifying trusts;
4. No shareholder may be a non-resident alien; and
5. The corporation may have only one class of stock.

The treatment of S corporations for state income tax purposes may vary from state to state. Some states may require a separate S corporation election for state tax purposes; others accept the federal election. Some states simply fail to recognize S corporations as conduit entities and treat them like regular corporations for state tax purposes.

LIMITED LIABILITY COMPANY

A limited liability company is an entity that is formed under state statutes, which allow it to combine the corporate characteristic of limited liability with the tax-conduit characteristics of a partnership. Virtually every state now has limited liability company statutes in place, and the use of this entity has become more widespread. An oil and gas entity seeking the advantages of a hybrid entity, but which cannot qualify for S corporation status, should consider limited liability company status as an entity choice.

INCOME TAX CREDITS

SECTION 29 CREDIT FOR NONCONVENTIONAL FUELS

Internal Revenue Code Section 29 allows income tax credits for *nonconventional fuels* production generally before the year 2003. The most common nonconventional fuels are natural gas from coalbeds (*coalbed methane*) and from *Devonian shale* and *tight sands* formations using certain wells spudded before 1993. The credit ranges from a fixed 51.7 cents per MMBtu for tight sands gas to an inflation-adjusted credit for coalbed methane approximating $1.12/MMBtu by 1999.

Although the tax credit is limited to a small number of gas wells, the credit can be substantial for such wells and exceed the wells' pre-tax cash flows prior to the year 2003. The tax credit is nonrefundable, and many economic interest holders of such production have too little taxable income to fully use the credit. Some E&P companies and royalty owners have monetized the credits by selling their economic interests in such production to parties with sufficient taxable income from other sources who are willing to pay a premium to own production that generates substantial income tax credits.

SECTION 43 CREDIT FOR ENHANCED OIL RECOVERY

Internal Revenue Code Section 43 allows an income tax credit for qualifying costs paid or incurred as part of an enhanced oil recovery (EOR) project. The credit is equal to 15 percent of qualified costs attributable to qualified domestic EOR projects. In general, a qualified EOR project is a domestic project that involves the application of a qualified tertiary recovery method. An EOR project must be located in the U.S. and meet certain other criteria specified in the income tax regulations. In addition, a petroleum engineer must certify that an EOR project meets the specified requirements in Section 43. Approved qualified tertiary recovery methods include:

1. Cyclic steam injection,
2. Steam drive injection,
3. In situ combustion,
4. Gas flood recovery methods,
5. Carbon dioxide augmented waterflooding,
6. Immiscible carbon dioxide displacement,
7. Immiscible nonhydrocarbon gas displacement,
8. Chemical flood recovery methods,
9. Caustic flooding, and
10. Mobility control recovery method.

Qualifying EOR costs include qualified tertiary injectant expenses, intangible drilling and development costs, and tangible property costs paid or incurred with respect to an asset that is used for the primary purpose of implementing an EOR project.

Chapter Twenty-Seven

ACCOUNTING FOR INCOME TAXES

INTRODUCTION

Accounting for the financial statement impact of income taxes has been deliberated for more than a decade. Prior to FAS 109, *Accounting for Income Taxes*, and its predecessor, FAS 96, income taxes were accounted for under APB Opinion No. 11 using an income statement approach. Under that approach, the income tax provision is calculated on income determined under GAAP or *book* income, with two key provisions:

1. GAAP income is adjusted to exclude permanent differences between book income and taxable income and
2. Differences between net assets' book bases and net assets' income tax bases are ignored.

The difference between the GAAP income tax provision and current income taxes based on taxable income is the deferred tax provision that adjusts the deferred tax liability. Over time, particularly as tax rates change, the deferred tax liability can become a meaningless amount.

APB Opinion No. 11, issued in 1967, was widely criticized for its complexity, burdensome recordkeeping requirements, and meaningless deferred tax "liability." Some accountants believed that a deferred tax liability under APB Opinion No. 11 often materially misstated a company's future tax liability. In effect, a deferred tax liability recorded on a company's books might never be paid. This concern caused users of financial statements to question the meaningfulness of the reported results.

As a result, the FASB added accounting for income taxes to its agenda in 1982. This project resulted in FAS 96 in 1987 and FAS 109 in 1992. FAS 109 radically changed the method used to account for income taxes. Specifically, FAS 109 adopted the liability method or balance sheet approach to account for deferred income taxes. Under the balance sheet approach, deferred taxes represent the future tax consequences of transactions already reported in a company's financial statements. The deferred tax liability is calculated first, and the net change in the net liability becomes the provision for deferred income taxes.

BASIC FRAMEWORK

The balance sheet approach is consistent with the FASB's conceptual framework, which is an asset-and-liability approach. Under FAS 109, the focus is on the balance sheet and on the proper determination of deferred tax assets and liabilities.

FAS 109 embraces the following basic principles:

- A current liability or asset is recognized whenever a current year's taxes are payable or refundable.
- A deferred liability or asset is recognized whenever there will be future tax effects from existing temporary differences and operating loss and tax credit carryforwards.
- The measurement of liabilities or assets is based on the provisions of enacted tax law as of the balance sheet date. The effects of anticipated changes in tax laws or rates are not considered.
- Where applicable, deferred tax assets are reduced by a valuation allowance for amounts that are not expected to be realized.

In order to satisfy the above principles, a company must develop a structured approach to comply with FAS 109. This approach must be focused on the series of sequential functions needed to comply with this standard. This chapter presents the following step-by-step approach:

Step 1: Identify types and amounts of temporary differences.
Step 2: Fragment temporary differences.
Step 3: Measure tax effects of temporary differences.
Step 4: Assess need for a valuation allowance.
Step 5: Determine financial statement presentation.
Step 6: Make financial statement disclosures.

IDENTIFYING TYPES AND AMOUNTS OF TEMPORARY DIFFERENCES

DIFFERENCES BETWEEN GAAP AND THE TAX CODE

The financial reporting objective is to determine income by applying Generally Accepted Accounting Principles (GAAP). GAAP is designed to "present fairly the financial condition" of a company at a point in time. GAAP requires the subjective evaluation of past, as well as certain future, events that are expected to impact the financial condition of a company. As a result, a company's financial reporting income is based primarily on (1) a matching of costs with associated revenues, (2) estimates of recovery periods and useful lives of assets, and (3) allowances for impairments in the carrying values of assets.

In contrast, taxable income reflects events that occurred during each taxable period by applying very specific rules of the taxing jurisdiction where the operations occur. These rules [for the United States as codified in the Internal Revenue Code (the Code), related regulations, and court decisions] define when income is to be recorded and costs are to be recovered. For purposes of discussion, the balance of this chapter will relate primarily to operations in the United States, subject to the Internal Revenue Code. The principal objective is the measurement of the appropriate amount of tax due and the proper period in which the tax must be paid. Accordingly, tax rules are intended to restrict the taxpayer's ability to manipulate the determination of taxable income. Generally, the Code

- Specifically defines when a liability is accruable or *fixed*,
- Does not allow, except in rare cases, the use of loss reserves, contingency reserves, or impairment allowances,
- Identifies non-taxable transactions and non-deductible expenses,
- Establishes specific rules of property classification for depreciation,
- Does not allow anticipated future events to be considered, and
- Generally measures the timing of events based on *closed transactions*.

As a result, most companies will have significant differences between the time when income and deductions are reported under GAAP and under income tax rules. Pursuant to FAS 109, companies must determine the nature of these differences. As discussed below, there are two types of differences: permanent and temporary.

PERMANENT DIFFERENCES

Permanent difference is an archaic term used in APB Opinion No. 11 and not used in FAS 109, but still referred to in colloquial discussions of accounting for income taxes. Permanent differences generally represent income and/or expenses that are included in financial reporting income but are not taxable or deductible for tax purposes and are never anticipated to be. Permanent differences impact a company's current tax provision and effective tax rate, but do not impact its deferred tax account.

Permanent differences may also represent deductions for tax purposes that have no associated cost. An example is excess statutory, or percentage, depletion—the most common permanent difference for oil and gas exploration companies. The statutory depletion deduction is measured as a percentage of gross oil and gas income and was added to the Code in the 1920s as a tax incentive for oil and gas exploration. A company's allowable percentage depletion deduction is computed on a property-by-property basis and is subject to limitations, as explained in the preceding chapter. To the extent that a company's allowable percentage depletion exceeds its adjusted tax basis, a permanent difference results.

Other examples of permanent differences:

♦ Tax-exempt interest	Included in income for financial reporting but not included in taxable income.
♦ Penalties	Deductible for financial reporting but not for tax purposes.
♦ Nondeductible meals	50 percent (20 percent prior to 1/1/94) of such expense cannot be deducted for tax purposes.
♦ Goodwill amortization	Nonamortizable for tax purposes on assets acquired prior to 8/10/93.
♦ Dividends received	Nontaxable portion of dividends received by a corporation.

TEMPORARY DIFFERENCES

Temporary differences are those differences between the tax basis of assets or liabilities and their reported amounts in the corresponding GAAP balance sheet that are expected to create differences between future income tax and future GAAP tax provisions.

The following examples reflect the way temporary differences impact a company's current taxes payable, deferred tax liability or asset, and tax rate reconciliation disclosure.

Assume for examples #1 to #3:

- U.S. statutory tax rate of 40 percent in current year and 50 percent thereafter.
- No state income taxes.
- Company started in the current year.

	GAAP	Tax Rptg.
♦ Assets at year-end	$20,000	Varies
♦ Liabilities not related to taxes	$12,000	$12,000
♦ Equity contributed	$5,500	$5,500
♦ GAAP pre-tax income	$2,500	Varies

Example #1 below illustrates that if book bases equal tax bases, there are generally no deferred taxes and no deferred tax provision. FAS 109 provides some exceptions to this general rule.

Example #1: No Temporary Differences

Assumption:
- Book bases equal tax bases.

Taxes currently payable are [$2,500 x 40%] or $1,000.

Summarized Balance Sheets:

	GAAP	Tax Rptg.
Assets	$20,000	$20,000
Liabilities and Equity:		
Taxes currently payable	$ 1,000	$ 1,000
Deferred taxes	0	0
Other liabilities	12,000	12,000
Equity contributed	5,500	5,500
Retained earnings	1,500	1,500
	$20,000	$20,000

Rate Reconciliation:

Income before income taxes	$2,500	100%
Theoretical tax at statutory tax rate	$1,000	40%
Total income taxes	$1,000	40%

Example #2 illustrates that deferred taxes reflect temporary differences in the bases of assets and liabilities at future tax rates required under current law. Under FAS 109, the deferred tax provision is a change in the net deferred tax liability, not a function of GAAP income.

Example #2: No Temporary Differences

Assumptions:

- Percentage depletion is $700, and GAAP DD&A is $300, whereby taxable income is $400 less than pre-tax GAAP income:

	GAAP	Tax Rptg.
Lease acquisition costs	$2,000	$2,000
Less depletion	(300)	(700)
Net lease assets	$1,700	$1,300

This creates a temporary difference of $400 in GAAP assets that are not deductible in the future to reduce income taxes by $200 (at the applicable 50% tax rate).

- For simplicity, assume no temporary differences arising from IDC deductions and well equipment DD&A differences.

Taxable income is [$2,500 - $400], or $2,100.

	GAAP	Tax Rptg.
Pre-tax income	$2,500	$2,100
Current yr's taxes payable [$2,100 x 40%]	840	840
Deferred tax liability [$400 x 50%]	200	0
Tax provision for the first year	1,040	840
Net income and retained earnings	$1,460	$1,260

Summarized Balance Sheets:

	GAAP	Tax Rptg.
Assets:		
Leasehold costs, net of depletion	$ 1,700	$ 1,300
Other assets	18,300	18,300
	$20,000	$19,600
Liabilities and Equity:		
Taxes currently payable	$ 840	$ 840
Differed taxes	200	0
Other liabilities	12,000	12,000
Equity contributed	5,500	5,500
Retained earnings	1,460	1,260
	$20,000	$19,600

Rate Reconciliation:

Income before income taxes	$2,500	100.0%
Theoretical tax at statutory tax rate	$1,000	40.0%
Change in future tax rate in determining income taxes	40	1.6%
Total income taxes	$1,040	41.6%

Example #3: Temporary Differences and Excess Percentage Depletion

Assumptions:

- Percentage depletion is $2,200, and GAAP DD&A is $300. As a result, taxable income is $1,900 less than pre-tax GAAP income:

	GAAP	Tax Rptg.
Lease acquisition costs	$2,000	$2,000
Less depletion	(300)	(2,000)
Net lease assets	$1,700	$ 0
Statutory depletion in excess of bases		$ 200

This creates a temporary difference of $1,700 in GAAP assets that are not deductible in the future to reduce income taxes by $850 (at the applicable 50% tax rate).

- For simplicity, assume no temporary differences arising from IDC deductions and well equipment DD&A differences.

Taxable income is [$2,500 - $1,700 additional non-excess depletion - $200 excess depletion, or $600. However in computing retained earnings, excess depletion is ignored, just as it is ignored in computing the asset's tax basis for the balance sheet.

	GAAP	Tax Rptg.
Pre-tax income	$2,500	$800
Current yr's taxes payable [$600 x 40%]	240	240
Deferred tax liability [($17,000-$0) x 50%]	850	0
Tax provision for the first year	1,090	240
Net income and retained earnings	$1,410	$ 560

Summarized Balance Sheets:

	GAAP	Tax Rptg.
Assets:		
Leasehold costs, net of depletion	$ 1,700	$ 0
Other Assets	18,300	18,300
	$20,000	$18,300
Liabilities and Equity:		
Taxes currently payable	$ 240	$ 240
Differed taxes	850	0
Other liabilities	12,000	12,000
Equity contributed	5,500	5,500
Retained earnings	1,410	560
	$20,000	$18,300

Rate Reconciliation:

Income before income taxes	$2,500	100.0%
Theoretical tax at statutory tax rate	$1,000	40.0%
Change in future tax rate in determining income taxes*	170	6.8
Statutory depletion in excess of tax basis**	(80)	(3.2)%
Total income taxes	$1,090	43.6%

*$1,700 basis difference x (50% - 40%) = $170. $170/$2,500 = 6.8%.
**$200 excess depletion x 40% = $80. ($80)/$2,500 = (3.2%).

The balance sheet approach of FAS 109 applies a new standard to accounting for income taxes that was not present under APB Opinion No. 11. This approach requires a company to maintain both a financial reporting balance sheet and a tax balance sheet. The difference in the balance sheets is principally, but not exclusively, the result of cumulative variances in the company's financial reporting income and previous tax returns. Additionally, variances in the financial reporting and tax balance sheets result from the different manner in which stock and asset acquisitions are accounted for under purchase accounting. These cumulative temporary differences comprise the bases for the company's deferred tax liability or asset.

FRAGMENTING TEMPORARY DIFFERENCES

Once a company has identified all its financial reporting and tax basis differences (cumulative temporary differences), FAS 109 requires the differences to be fragmented between taxable and deductible differences.

TAXABLE TEMPORARY DIFFERENCES

Temporary differences, which will produce taxable income in future tax years, are referred to as taxable differences. Taxable temporary differences produce a deferred tax liability. For instance, a taxable difference typically represents the company's financial reporting basis for an asset exceeding its tax basis. Generally, taxable differences relate to tax deductions claimed for tax purposes before the year in which the deduction is reflected for financial reporting. A prime example of a taxable difference relates to depreciable property that has a more rapid recovery period for tax purposes than for book purposes. For oil and gas exploration and production companies, the most common taxable temporary difference is associated with IDCs which, for tax purposes, are typically expensed in the year incurred.

Examples of taxable temporary differences:

♦ Depreciation	Accelerated rates used for tax.
♦ IDC	Expensed for tax and capitalized for book under both successful efforts and full cost except for exploratory dry holes under successful efforts.
♦ Delay rentals	Expensed for tax purposes unless taxpayer elects to capitalize or is required to capitalize all or a portion under IRC Section 263A. For financial reporting, expensed under successful efforts and capitalized under full cost.
♦ Dry hole costs:	
♦ Exploratory	Expensed for tax purposes. For financial reporting, expensed under successful efforts and capitalized under full cost.
♦ Development	Expensed for tax purposes and capitalized for financial reporting under both successful efforts and full cost.
♦ Installment sales	Profit recorded in year of sale for financial reporting. Profit deferred and recorded as received for tax purposes, potentially subject to an interest charge.
♦ Purchase accounting	Stock acquisition treated as a purchase for financial reporting. For tax purposes, stock acquisition generally requires the purchaser to assume the normally smaller tax basis of the seller, similar to a pooling.

DEDUCTIBLE TEMPORARY DIFFERENCES

Deductible differences will produce a tax benefit or deduction in a future tax year. Deductible differences often are the result of the company's tax basis for an asset exceeding its financial reporting basis. These temporary differences produce a deferred tax asset. Generally, deductible differences relate to deductions that have been taken for financial reporting purposes but have not been deducted for tax purposes. Net operating losses and tax credit carryovers are also treated as deductible temporary differences.

Examples of deductible temporary differences:

♦ Reserves/allowances	Generally not deductible for tax purposes until liability deemed to be *fixed* or actually paid.
♦ Impairments	Allowances for unproved property impairment are not deductible for tax purposes until the lease has expired and/or lease acreage is abandoned.
♦ Geological and geophysical	Expensed for financial reporting under successful efforts and capitalized for tax if leases are acquired as a result of G&G expenditures.
♦ Sublease of unproved property	Proceeds are ordinary income for tax purposes and generally treated as recovery of costs for financial reporting.
♦ Sale of part of property	Gain or loss recognized for tax purposes. Proceeds generally treated as recovery of cost for financial reporting.

♦ Deficiency payment received under take-or-pay contract	Taxable when received for tax purposes and treated as deferred revenue (if recoverable and recovery is likely) for financial reporting.
♦ Bad debts	Reserve method generally cannot be used by most taxpayers. For tax purposes specific identification methods must normally be used.
♦ Post-retirement benefits	Reserve for post-retirement benefits per FAS 106 not deductible for tax until benefits are paid.
♦ Equity method of accounting vs. cost	Certain investments may be accounted for on the equity method for financial method reporting and the cost method for tax purposes (generally because the subsidiary is less than 80 percent owned and not included in the consolidated tax return). In certain instances, due to the indefinite reversal criteria of APB Opinion No. 23, this difference may be treated as a permanent difference.
♦ Organization expenses	Expensed as incurred for financial reporting while capitalized and amortized over five years for tax purposes.
♦ Inventory capitalization	For tax purposes, additional costs are required to be capitalized on inventory and self-constructed assets pursuant to IRC 263A.
♦ Carryovers - net operating losses, investment tax credits, AMT	These tax assets result from losses, business tax credits, or alternative minimum taxes paid in prior years that are available to reduce future regular tax.

Fragmenting temporary differences is complicated when an asset's carrying value reflects both prior taxable and deductible temporary differences. For example, capitalized proved oil and gas property costs may reflect prior *deductible* temporary differences due to impairment (recorded for GAAP but not for tax) and *taxable* temporary differences due to IDC tax deductions and accelerated tax depreciation (as illustrated in Example #4). Accumulated DD&A for GAAP may exceed accumulated DD&A for tax simply because GAAP capitalized costs include IDC deducted for tax purposes (as illustrated in Example #4) and not because GAAP DD&A occurs sooner than tax DD&A. In Example #4, the remaining net carrying costs of proved property will be expensed or deducted through DD&A, indicative of a taxable temporary difference for the GAAP net basis exceeding the tax net basis. Yet unproved property, as a separate asset or asset group, may give rise to a deductible temporary difference (as illustrated in Example #4).

Example #4: Fragmenting Temporary Differences
(Assume successful efforts accounting)

(000's)	GAAP Basis	Tax Basis	Temporary Difference
Proved lease cost(s	$ 100	$ 150	$ (50)
Successful well IDC	1,000	0	1,000
Successful well equipment	1,000	1,000	0
Development dry hole	500	0	500
FAS 121 impairment	(200)	0	(200)
DD&A	(250)	(150)	(100)
Net lease assets	$2,150	$1,000	$1,150
Unproved lease acquisitions	$ 500	$500	$ 0
Lease impairment	(50)	0	(50)
G&G costs on acquired leases	0	200	(200)
Net, unproved property	$450	$700	$(250)

Taxable temporary difference, proved property	$1,150,000
Deductible temporary difference, unproved property	$250,000

MEASURING TAX EFFECTS OF TEMPORARY DIFFERENCES

Once a company's temporary differences are identified and divided between taxable and deductible, they must be measured by the appropriate tax rate. The tax rate includes not only federal taxes but also state and foreign taxes that may be payable as the temporary differences reverse in the future. As a result, the impact of state and foreign tax laws in each taxing jurisdiction where the company is active must be considered. Accordingly, state tax apportionment factors, state operating losses, and foreign tax credit utilization are all factors that must be considered in arriving at the appropriate tax rate to be used to measure a company's temporary differences.

It is quite common for oil and gas companies to be subject to alternative minimum tax (AMT). AMT is a separate tax system intended to restrict companies from reducing their tax liability below a minimum amount by using specific tax incentives and/or preferences. The AMT a company pays in any given year that exceeds its regular tax liability will produce an AMT credit. This AMT credit can be carried forward indefinitely to reduce regular tax associated with both future taxable income and the reversal of temporary differences. Accordingly, the FASB concluded that deferred income taxes should be measured using the regular tax rates, not the AMT rate. This approach should be followed even if the company anticipates being subject to AMT for the foreseeable future.

The applicable tax rate is the enacted tax rate expected to apply in the future period in which the liability or asset is realized. Any change in the enacted tax rate is adjusted through the tax provision in the year of enactment.

Example #4 calculated a taxable temporary difference of $1,150,000 for proved property and a deductible temporary difference of $250,000 for unproved property. Assuming the proved properties are located in states in which the effective combined tax rate is 42 percent, the $1,150,000 taxable temporary difference generates a deferred tax liability of $483,000. Assuming that the unproved properties are located in states in which the effective combined regular income tax rate is 40 percent, the $250,000 deductible temporary difference generates a deferred tax asset of $100,000. Anticipated percentage depletion should not be considered in calculating temporary differences or their tax effects per FAS 109 paragraph 231.

ASSESSING NEED FOR A VALUATION ALLOWANCE

As described above, FAS 109 requires a company to compute tax on its separately identified *taxable* temporary differences. This computation arrives at the company's total deferred tax liability. The company is also required to compute the total deferred tax asset associated with its separately identified *deductible* temporary differences. This asset represents the tax benefits associated with expenses that have not been deducted for tax purposes, net operating losses, and tax credit carryovers. Before reflecting the benefits of a deferred tax asset, the company must assess its ability to utilize it. This assessment process utilizes a *valuation allowance* concept that was not present in APB Opinion No. 11 or FAS 96.

The FAS 109 creation of a valuation allowance process was designed to add a level of professional subjectivity not available in previous deferred tax methodologies. Under APB Opinion No. 11 and FAS 96, accounting for income tax was a very mechanical computation. Frequently these accounting methods produced inconsistent and unreliable deferred tax amounts. Accordingly, FAS 109 instilled a process to assess the value of its deferred tax asset similar to the process imposed on other types of assets owned by a company (e.g., bad debt reserve, inventory obsolescence, and impairment).

Under FAS 109 a company is allowed to record the benefit of a deferred tax asset only if it determines that it will be able to utilize all or a portion of its deductible temporary differences. This determination is made by applying a *more likely than not* standard. To satisfy this standard, the company must be able to represent that it is more likely than not that the deferred tax asset will be realized. *More likely than not* is defined as a greater than 50 percent probability. A company's ability to satisfy this standard requires the evaluation of (1) both positive and negative evidence and (2) all possible sources of taxable income.

POSITIVE EVIDENCE

A company's evaluation of positive evidence will be critical in its attempt to overcome negative evidence to support a conclusion that a valuation allowance is not required. Positive evidence and the evaluation of the company's sources of taxable income (mentioned below) are the key factors in analyzing a deferred tax asset. The following represent examples of positive evidence mentioned in FAS 109:

- Existing contracts or firm sales backlog that will produce sufficient taxable income to realize the deferred tax asset.
- An excess of appreciated asset value over the tax basis of the entity's net assets in amounts sufficient to realize the deferred tax asset.
- A strong earnings history exclusive of the loss that created the future deductible amount, and evidence that the loss was an aberration.

NEGATIVE EVIDENCE

A company, which possesses an abundance of negative evidence, will have more difficulty in supporting a conclusion that a valuation allowance is not required. While not all-inclusive, the following represents examples, mentioned in FAS 109, of negative evidence:

- A history of operating loss or tax credit carryforwards expiring unused.
- Losses expected in early future years (by a presently profitable entity).
- Unsettled circumstances that, if unfavorably resolved, would adversely affect future operations and profit levels.
- A carryback or carryforward period that is so brief it would limit realization of the tax benefit.

SOURCES OF TAXABLE INCOME

Once a company has assessed both positive and negative evidence, it must evaluate possible sources of taxable income. The benefit of a deferred tax asset can be recognized only if the company possesses sufficient sources of taxable income. FAS 109 defines four sources of taxable income:

- Reversal of existing taxable temporary differences,
- Taxable income in prior carryback years if carryback is permitted under tax law,
- Future taxable income exclusive of temporary differences and carryovers, and
- Tax planning strategies.

Not all of a company's sources of income as reflected above are treated equally. The ability of a company to utilize a tax asset as a result of the first two sources (reversal of taxable temporary differences and income in prior carryback years) is much easier than the last two, principally because the first two sources of income are based on historical transactions that have already occurred and accordingly have a substantially lower degree of risk.

The ability of a company to establish a deferred tax asset as a result of projecting future taxable income is a new approach that was not available to companies under APB Opinion No. 11 or FAS 96. This income source was considered to allow an increased level of objectivity in appraising a company's deferred tax asset. However, the inherent risk (exploration success, fluctuation in oil and gas prices, etc.) associated with an attempt to project future taxable income requires careful examination. Any income projection must correlate with the company's reserve report, FAS 121 expected future cash flows, and expected drilling and development (capital budget) expenditures. Reliance on a tax planning strategy requires a company to consider an action that would not necessarily be taken in the ordinary course of business, but would be taken to prevent a tax benefit from expiring. The tax planning strategy must be prudent, feasible, and not prohibited on the basis of cost.

DETERMINING FINANCIAL STATEMENT PRESENTATION

Once a company has determined the appropriate deferred tax asset or liability, it must then evaluate the proper manner in which the deferred account is required to be presented in its financial statements. FAS 109 requires that each temporary difference be classified as current or noncurrent based on classification of the related asset or liability for financial reporting. As an example, a temporary difference that relates to a noncurrent asset (such as depreciable property or IDC) would be treated as a noncurrent deferred tax asset or liability. Accordingly, a temporary difference that relates to a current asset (such as inventory or accounts receivable) would be classified as a current deferred tax asset or liability. A deferred tax liability or asset that is not related to an asset or liability for financial reporting is classified based on expected reversal date.

All current deferred tax liabilities and assets shall be offset and presented as a single amount, and all noncurrent deferred tax liabilities and assets shall be offset and presented as a single amount. For example, assume that one taxpaying entity's unproved property assets generate a $100,000 noncurrent deferred tax asset and proved property assets generate a $504,000 noncurrent deferred tax liability in the same tax jurisdiction. The balance sheet would reflect a net $404,000 noncurrent deferred tax liability (but the tax note to the financial statements would disclose the components, as explained in the next section of this chapter). Amounts are not offset for different taxpaying subsidiaries or for assets in different tax jurisdictions.

A company should allocate any valuation allowance between current and noncurrent deferred tax assets on a pro-rata basis.

MAKING FINANCIAL STATEMENT DISCLOSURES

FAS 109 requires disclosure of information related to income tax accounts that are presented in the balance sheet and income statement of a company.

BALANCE SHEET

A company is required to disclose the components of a net deferred tax asset or liability presented in the balance sheet. Specifically, the company must disclose the following in a note to the financial statements:

(1) The total of all deferred tax liabilities,
(2) The total of all deferred tax assets, and
(3) The total valuation allowance.

The company must also disclose the net change in the total valuation allowance during the year. A public enterprise shall disclose the tax effect of each type of significant temporary difference and carryforward. A nonpublic enterprise shall disclose the type of significant temporary differences but may omit disclosure of the tax effect.

For example, assume that a publicly held E&P company has net operating loss carryforwards and AMT credit carryforwards. These generate deferred tax assets, subject to a valuation allowance. The footnote disclosure might read as follows:

For financial reporting, the components of the net deferred asset at December 31, 1999, were as follows (in thousands):

Deferred tax assets	
NOL carryforwards	$20,000
AMT credit carryforwards	1,000
Other	500
	21,500
Deferred tax liabilities	
Proved property	(15,000)
Other	(400)
	(15,400)
Deferred tax assets net of liabilities	6,100
Valuation allowance	(4,100)
Net deferred tax asset	$ 2,000

The December 31, 1999, valuation allowance was $1,000,000 less than at December 31, 1998.

Additionally, a company must disclose information when a potential deferred tax liability is not required to be recognized. Specifically, certain types of temporary differences are provided an exception from the required recognition of deferred tax. Deferred tax is not recognized for the following types of temporary differences unless it becomes apparent that such temporary differences will reverse in the foreseeable future:

- An excess of the amount of financial reporting over the tax basis of an investment in a foreign subsidiary or foreign corporate joint venture that is essentially permanent in duration,
- Undistributed earnings of a domestic subsidiary or a domestic corporate joint venture that is essentially permanent in duration that arose in fiscal years beginning on or before December 31, 1992, and
- Bad debt reserves of savings and loan associations and policy-holders' surplus of stock life insurance companies.

A company must disclose a description of the types of temporary differences that have not been recognized, the type of event that would cause the difference to become taxable, and the amount of the unrecognized deferred tax liability that is not recognized.

INCOME STATEMENT

The significant components of income tax expense attributable to continuing operations for each year presented are required to be disclosed. The company should disclose the amount of current tax expense or benefit and the amount of deferred tax expense or benefit. Additionally, the company should disclose the benefits of operating loss carryforwards, the impact of a change in enacted tax laws or rates, and any adjustments to the beginning-of-the-year valuation allowance resulting from a change in circumstances about the realizability of the related asset.

A public company shall disclose a reconciliation using percentages or dollar amounts of the reported income tax expense to the amount of income tax expense that would result from applying domestic federal statutory tax rates to pre-tax income. The amount and nature of each significant reconciling item shall be disclosed. A nonpublic company may disclose the nature of significant reconciling items but may omit a numerical reconciliation. For example, a public company might disclose the following in the income tax note to the financial statements:

	2000	1999	1998
Federal statutory rate	35%	35%	35%
Utilization of net operating loss carryforwards	(33)	(34)	(33)
Other	1	-	-
Effective income tax rate	3%	1%	2%

A company shall disclose the (1) amount and expiration of operating loss and tax credit carryforwards and (2) any portion of the valuation allowance for which subsequent recognition will be required to be allocated to goodwill or other noncurrent intangible assets of an acquired entity. A company that is a member of a group that files a consolidated tax return shall disclose the amount of current and deferred tax expense, the amount of any tax-related balances due to or from affiliates, and the principal provisions by which deferred taxes are allocated among members of the group.

OTHER CONSIDERATIONS

INTERCORPORATE TAX ALLOCATION

FAS 109 provides rules for allocating taxes to subsidiaries that issue separate financial statements and are included in a consolidated tax return. Although FAS 109 does not require a single allocation method, it does require that the method used be consistent with the broad principles of the standard.

FAS 109 specifically prohibits the following:

- A method that allocates only current taxes payable to a member of a group that has taxable temporary differences,
- A method that allocates deferred taxes to a member of a group using a method fundamentally different (e.g., the APB Opinion No. 11 method) from the balance sheet method of FAS 109, and
- A method that allocates no current or deferred tax expense to a member of a group that has taxable income because the consolidated group has no current of deferred tax expense.

BUSINESS COMBINATIONS

Deferred taxes must be recognized on differences between the assigned financial reporting and the tax basis of acquired assets and assumed liabilities. The only exceptions are that a deferred tax liability is not recognized for differences related to goodwill that are not tax-deductible, unallocated negative goodwill, acquired leveraged leases, and APB Opinion No. 23 differences recognized in an acquisition (e.g., undistributed earnings of subsidiaries, investments in corporate joint ventures, *bad debt* reserves of savings and loan associations, and *policyholders' surplus* of stock life insurance companies).

If a valuation allowance is recognized for the deferred tax asset for an acquired entity's deductible temporary differences, operating loss, or tax credit carryforwards at the acquisition date, the tax benefits for those items that are first recognized (that is, by elimination of the valuation allowance) in financial statements after the acquisition date shall be applied:

- First, to reduce to zero any goodwill related to the acquisition,

- Second, to reduce to zero other noncurrent intangible assets related to the acquisition, and
- Third, to reduce income tax expense.

If financial statements for prior years are restated, all *purchase* business combinations that were consummated in those prior years must be remeasured. Generally, for a business combination consummated prior to the beginning of the year for which FAS 109 is first applied, balances remaining, except for goodwill, should be adjusted to their pre-tax amounts. However, when determination of the adjustment for any or all of the assets and liabilities is impracticable, none of the remaining balances of any assets and liabilities acquired in that combination are adjusted to pre-tax amounts (i.e., none of the remaining amounts that were originally assigned on a net-of-tax basis pursuant to APB Opinion No. 16 should be adjusted).

INTERIM FINANCIAL REPORTING

At the end of each interim period, a company should make its best estimate of the annual income tax rate and apply that rate to year-to-date pre-tax income to arrive at the year-to-date income tax provision. The determination of the estimated annual effective tax rate should reflect tax benefits expected to be realized during the year or recognizable at the end of the year as a deferred tax asset. However, the effect of a change in the beginning-of-the-year balances of a valuation allowance as a result of a change in judgment about the realizability of a related deferred tax asset in future years should not be apportioned among interim periods, but should be recognized in the interim period in which the change occurs.

Chapter Twenty-Eight

NONVALUE DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES

This chapter focuses on the nonvalue disclosures required by Statement of Financial Accounting Standards No. 69 (FAS 69), entitled *Disclosures About Oil and Gas Producing Activities* and reflected in *Current Text*, Oi5.156 through Oi5.408. Related SEC disclosure rules and miscellaneous full cost disclosures are also addressed.

HISTORY OF DISCLOSURE REQUIREMENTS

In FAS 19, issued in December 1977, the FASB not only adopted a form of successful efforts accounting, but also specified certain *supplemental data* to be included in financial reports of oil and gas producing companies. The FAS 19 nonvalue disclosure requirements were for (1) mineral reserve quantities, (2) capitalized costs, and (3) costs incurred.

In August 1978, before Statement 19 became effective, the SEC issued ASR No. 253. That release (1) adopted the form of successful efforts accounting prescribed by Statement 19, (2) indicated an intention to adopt the disclosures prescribed by FAS 19 (which was subsequently done), (3) indicated an intention to adopt a form of the full cost accounting method (which was subsequently done), (4) permitted the use of either successful efforts or full cost accounting for SEC reporting purposes, and (5) adopted rules that require disclosure of certain financial and operating information beyond that required in FAS 19. The SEC took those actions because it believed that neither the full cost nor the successful efforts method provided sufficient information on the financial position and operating results of oil and gas producing enterprises. Accordingly, the SEC concluded that a new method of accounting that is based on valuations of proved oil and gas reserves and that would replace both successful efforts and full cost accounting methods should be developed for the primary financial statements. The SEC initiated the development of that new accounting method (which it referred to as *reserve recognition accounting*, or *RRA*) by requiring supplemental disclosures on that basis. The SEC also indicated (and subsequently carried out) its intention to require the disclosure of a supplemental earnings summary to reflect estimated additions to proved reserves and changes in valuation of estimated proved reserves, based on current prices and costs and a ten percent annual discount rate. All costs associated with finding and developing such additions and all costs determined to be nonproductive during the period were to be deducted in determining that supplemental measure of earnings.

The issuance of ASR 253 meant that FAS 19 would be imposed only on enterprises not subject to SEC reporting requirements and therefore would not achieve comparability. So the FASB issued FAS 25 in February 1979 that suspended the effective date of FAS 19 as to the accounting method to be used in financial statements but not as to the disclosure requirements.

In February 1981, the SEC issued ASR No. 289, *Financial Reporting by Oil and Gas Producers*, which stated that the SEC no longer considered RRA to be a potential method of accounting in the primary financial statements of oil and gas producers. That release also announced the SEC's "support of an undertaking by the Financial Accounting Standards Board to develop a comprehensive package of disclosures for those engaged in oil and gas producing activities." The SEC indicated in that release that the SEC expected to amend its rules to be consistent with the disclosure standards to be developed by the FASB for oil and gas producers.

In November 1982, the FASB issued FAS 69, which applies mostly to *publicly traded* companies. In December 1982, the SEC issued Reg. SK §229.302 (excerpts included on App. 1-26) adopting FAS 69 to replace the SEC's own requirements for disclosure about oil and gas producing activities.

OVERVIEW OF DISCLOSURES

Following is a listing of various disclosures on oil and gas activities required by FAS 69, SEC rules, and other accounting pronouncements:

1. FAS 69 requires that *every enterprise*, whether publicly traded or not, with *significant* oil and gas activities must disclose in its financial statements (1) its *method of accounting* for costs incurred in such activities and (2) its *manner of disposing of capitalized costs* relating to those activities.

2. Under FAS 69, every *publicly traded enterprise* with *significant* oil and gas activities must disclose with complete sets of *annual* financial statements certain *supplemental* information (that need not be audited) as to the following:
   a. Proved oil and gas reserve quantities;
   b. Capitalized costs relating to oil and gas producing activities;
   c. Costs incurred for property acquisition, exploration, and development activities;
   d. Results of operations for oil and gas producing activities;
   e. A standardized measure of discounted future net cash flows relating to proved oil and gas reserve quantities as of year-end and the year's change in the standardized measure.
3. FAS 69 requires that interim financials include information about a major discovery or other favorable or adverse event that causes a significant change from the most recent annual supplemental disclosures concerning oil and gas reserves.
4. APB 20 on accounting policies calls for any significant accounting policy to be disclosed. Examples for E&P activities might include the following:
   a. The policy of accruing net DR&A costs through DD&A amortization,[89]
   b. The policy for capitalizing internal costs associated with E&P activities, and[90]
   c. The method of accounting for gas balancing (i.e., sales method or entitlements method).[91]

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[89]SAB 92 (Topic 5Y, Question 7) implies that if DR&A costs are material, appropriate related footnote disclosures would include, at a minimum, the nature of the costs involved, total anticipated costs, total costs accrued to date, balance sheet classification of accrued costs, the range or amount of reasonably possible additional losses, and other possible additional disclosures noted in Topic 5Y.

[90]As noted in AICPA Audit Risk Alert, *Oil and Gas Producers Industry Developments - 1993.*

[91]Under EITF 90-22, an SEC registrant should disclose its method of accounting for gas balancing (i.e., sales method or entitlements method) as well as the amount of any imbalance in terms of both units and value, if significant. Additional disclosures may be necessary. In two known instances, the SEC staff asked registrants using the entitlements method to also disclose how revenues were recognized, how the company accounted for its share of production expenses, and how the receivable or liability was recorded.

5. For enterprises following the Reg. S-X Rule 4-10 full cost method, additional disclosures are presented:
   a. Disclosure of *total amortization expense* for each cost center for each year an income statement is presented.
   b. Stating separately on the face of the balance sheet the total *capitalized costs excluded from the amortization base* and providing certain related disclosures in the notes to the financial statements.
   c. Disclosures relating to any *ceiling test write-down* or subsequent events that eliminate or reduce the write-down.
6. For oil and gas exchange offers, SEC SAB Topic 2D contains special disclosure requirements.
7. SEC rules require additional disclosures of oil and gas operations outside of the financial statements, as further explained at the end of this chapter.

The remainder of this chapter further addresses these disclosure requirements, other than the standardized measure (addressed in Chapter Twenty-Nine), the interim financial disclosure requirements (which are self-explanatory), the APB 20 accounting policy disclosure requirements (addressed in various other chapters), and the Topic 2D disclosures for oil and gas exchange offers (which are relatively rare now).

WHAT ARE "SIGNIFICANT" OIL AND GAS PRODUCING ACTIVITIES?

FAS 69 disclosures are required for enterprises with *significant* oil and gas producing activities. An enterprise is deemed under FAS 69 (through reference to FAS 131) to have significant oil and gas producing activities if such activities are at least ten percent of the company's total activities, as indicated by any one of the following three ratios:

1. Revenues from oil and gas producing activities (including both sales to unaffiliated customers and sales or transfers to the enterprise's other operations) are ten percent or more of the combined revenues (including sales to unaffiliated customers and sales or transfers to the enterprise's other operations) of all the enterprise's industry segments.
2. Results of operations of oil and gas producing activities (excluding the effects of income taxes) are ten percent or more of the larger of:

(a) the combined operating profit of all industry segments that did not incur an operating loss, or

(b) the combined operating loss of all industry segments that did incur an operating loss.

3. The identifiable assets of oil and gas producing activities (tangible and intangible enterprise assets that are used by oil and gas producing activities, including an allocated portion of assets used jointly with other operations) are ten percent or more of the assets of the enterprise, excluding assets used exclusively for general corporate purposes.

The SEC provides that an enterprise's oil and gas activity will be viewed by the SEC as *significant* for FAS 69 disclosure requirements if "the discounted present value of a registrant's oil and gas reserves is significantly in excess of ten percent of consolidated total assets" even if the three FAS 131 ratio tests noted above are not met.[92] The SEC rules do not define what is *significantly in excess of ten percent*.

WHAT IS MEANT BY PUBLICLY TRADED?

FAS 69, footnote 2, provides that for purposes of FAS 69 the term *publicly traded enterprise* refers to:

> a business enterprise (a) whose securities are traded in a public market on a domestic stock exchange or in the domestic over-the-counter market (including securities quoted only locally or regionally) or (b) whose financial statements are filed with a regulatory agency in preparation for the sale of any class of securities in a domestic market.

Under the SEC's rules, some enterprises that are not technically *publicly traded* may be required to make FAS 69 disclosures. For example, partnerships and enterprises operating under *Regulation D* exemptions are viewed as *publicly traded* for FAS 69 disclosure requirements.[93] Certain

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[92]SEC's Codification of Financial Reporting Releases, 406.02.d.i, reproduced at App. 1-19.

[93]SEC's Codification of Financial Reporting Releases, 406.02.d.ii, reproduced at App. 1-20.

limited partnerships may be able to secure a waiver from the SEC that will permit them to omit the present value disclosure requirements.[94]

DATES AND PERIODS OF THE DISCLOSURES

The supplemental disclosures are required for complete sets of annual financial statements (whether audited or unaudited) per FAS 69 and for incomplete sets per SEC Financial Reporting Release 9 (FRR 9). FRR 9 provides that for each year an income statement is required, the company should disclose FAS 69 matters relating to the annual period and to the beginning of such period. The only FAS 69 disclosures relating to the beginning of a period are proved and proved developed reserves. For each required audited balance sheet, FRR 9 requires only the disclosures relating to that balance sheet date.

In the normal annual report Form 10-K filing with the SEC, audited balance sheets are required for the two latest year ends, and statements of income and cash flow are required for the latest three years. In such cases, the supplemental disclosures are required for the following dates and periods:

- Reserve quantities as of the last four year-end dates and reserve quantity changes for each of the last three years,
- Capitalized cost disclosures as of the end of the year for each of the two year-end balance sheet dates,
- Costs-incurred disclosures for the year for each of the three years of income statements,
- Results of operations disclosures for the year for each of the three years of income statements, and
- Standardized measure as of the last two year-end dates and standardized measure changes for each of the last three years.

Figures in this chapter and Chapter Twenty-Nine include examples of such disclosures from ExxonMobil's 1999 Annual Report.

[94] SEC's Codification of Financial Reporting Releases, 406.02.d.iii, reproduced at App. 1-20.

FAS 69 NONVALUE DISCLOSURES AND RELATED SEC RULES

DISCLOSING THE METHOD OF ACCOUNTING AND THE MANNER OF DISPOSING OF CAPITALIZED COSTS

Under FAS 69 all enterprises engaged in significant oil and gas producing activities must disclose in their financial statements the method of accounting for costs incurred (e.g., successful efforts) and the manner of disposing of capitalized costs relating to these activities (Accounting Method Disclosure). This is the only FAS 69 disclosure requirement that is not considered to be *supplemental*. Thus, the Accounting Method Disclosure is deemed to be an integral part of the financial statements. The accounting method can be disclosed on the face of the financial statements, in notes to the statements, or both, or in some other fashion indicating that the disclosure is an integral part of the statements.[95] The manner of disposing of capitalized costs is disclosed in notes to the statements.

An example of the Accounting Method Disclosure is found in *Notes to Consolidated Financial Statements* in ExxonMobil's 1999 Annual Report:

> **Property, plant and equipment.** . . . The corporation's exploration and production activities are accounted for under the "successful efforts" method. Under this method, costs of productive wells and development dry holes, both tangible and intangible, as well as productive acreage are capitalized and amortized on the unit-of-production method. Costs of that portion of undeveloped acreage likely to be unproductive, based largely on historical experience, are amortized over the period of exploration. Other exploratory expenditures, including geophysical costs, other dry hole costs and annual lease rentals, are expensed as incurred. Exploratory wells that find oil and gas in an area requiring a major capital expenditure before production could begin are evaluated annually to assure that commercial quantities of reserves have been found or that additional exploration work is underway or planned. Exploratory well costs not meeting either of these tests are charged to expense.

[95] Reg. S-X Rule 4-10, Subsection (k), deleted in 1992 by Financial Reporting Release 40A, required that the method of accounting be disclosed on the face of the balance sheet. Today, the accounting method may simply be disclosed in the financial statement note on significant accounting policies.

DISCLOSING RESERVE QUANTITY INFORMATION

FAS 69, Paragraphs 10 through 17 (Oi5.160 through Oi5.167), requires publicly traded enterprises to annually disclose certain data related to an enterprise's proved oil and gas reserves as supplemental information:

10. Net quantities of an enterprise's interest in proved reserves and proved developed reserves of (a) crude oil (including condensate and natural gas liquids)[96] and (b) natural gas shall be reported as of the beginning and the end of the year. *Net* quantities of reserves include those relating to the enterprise's operating and nonoperating interests in properties as defined in paragraph 11(a) of Statement 19. Quantities of reserves relating to royalty interests owned shall be included in *net* quantities if the necessary information is available to the enterprise; if reserves relating to royalty interests owned are not included because the information is unavailable, that fact and the enterprise's share of oil and gas produced for those royalty interests shall be disclosed for the year. *Net* quantities shall not include reserves relating to interests of others in properties owned by the enterprise.
11. Changes in the net quantities of an enterprise's proved reserves of oil and gas during the year shall be disclosed. Changes resulting from each of the following shall be shown separately with appropriate explanation of significant changes:
    a. *Revisions of previous estimates.* Revisions represent changes in previous estimates of proved reserves, either upward or downward, resulting from new information (except for an increase in proved acreage) normally obtained from development drilling and production history or resulting from a change in economic factors.
    b. *Improved recovery.* Changes in reserve estimates resulting from application of improved recovery techniques shall be shown separately if significant. If not significant, such changes shall be included in revisions of previous estimates.
    c. *Purchases of minerals in place.*

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[96]Note 5 of FAS 69 states that "if significant, the reserve quantity information shall be disclosed separately for natural gas liquids." *Authors' note:* Various methods of disclosing NGL reserve quantities are currently used. As noted above, most companies disclose natural gas liquids with oil reserves. Some companies disclose wet gas reserves (before removal of NGLs), effectively including NGL reserves in natural gas reserves as opposed to oil reserves. Some of those companies also separately disclose NGL reserves, and financial statement users need to be careful not to double-count the NGL reserves.

d. *Extensions and discoveries.* Additions to proved reserves that result from (1) extension of the proved acreage of previously discovered (old) reservoirs through additional drilling in periods subsequent to discovery and (2) discovery of new fields with proved reserves or of new reservoirs of proved reserves in old fields.
e. *Production.*
f. *Sales of minerals in place.*

12. If an enterprise's proved reserves of oil and of gas are located entirely within its home country, that fact shall be disclosed. If some or all of its reserves are located in foreign countries, the disclosures of net quantities of reserves of oil and of gas and changes in them required by paragraphs 10 and 11 shall be separately disclosed for (a) the enterprise's home country (if significant reserves are located there) and (b) each foreign geographic area in which significant reserves are located. Foreign geographic areas are individual countries or groups of countries as appropriate for meaningful disclosure in the circumstances.
13. Net quantities disclosed in conformity with paragraphs 10-12 shall not include oil or gas subject to purchase under long-term supply, purchase, or similar agreements and contracts, including such agreements with governments or authorities. However, quantities of oil or gas subject to such agreements with governments or authorities as of the end of the year, and the net quantity of oil or gas received under the agreements during the year, shall be separately disclosed if the enterprise participates in the operation of the properties in which the oil or gas is located or otherwise serves as the *producer* of those reserves, as opposed, for example, to being an independent purchaser, broker, dealer, or importer.[97]
14. In determining the reserve quantities to be disclosed in conformity with paragraphs 10-13:
    a. If the enterprise issues consolidated financial statements, 100 percent of the *net* reserve quantities attributable to the parent company and 100 percent of the *net* reserve quantities attributable to its consolidated subsidiaries (whether or not wholly owned) shall be included. If a significant portion of those reserve quantities at the end of the year is attributable to a consolidated subsidiary(ies) in which there is a significant minority interest, that fact and the approximate portion shall be disclosed.
    b. If the enterprise's financial statements include investments that are proportionately consolidated, the enterprise's reserve quantities shall include its proportionate share of the investees' net oil and gas reserves.

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[97] See Chapter Twenty-Five for further discussion of this disclosure requirement.

c. If the enterprise's financial statements include investments that are accounted for by the equity method, the investees' net oil and gas reserves shall *not* be included in the disclosures of the enterprise's reserve quantities. However, the enterprise's (investor's) share of the investee's net oil and gas reserve quantities shall be separately reported as of the end of the year.

15. In reporting reserve quantities and changes in them, oil reserves and natural gas liquids reserves shall be stated in barrels, and gas reserves in cubic feet.
16. If important economic factors or significant uncertainties affect particular components of an enterprise's proved reserves, explanation shall be provided. Examples include unusually high expected development or lifting costs, the necessity to build a major pipeline or other major facilities before production of the reserves can begin, and contractual obligations to produce and sell a significant portion of reserves at prices that are substantially below those at which the oil or gas could otherwise be sold in the absence of the contractual obligation.
17. If a government restricts the disclosure of estimated reserves for properties under its authority, or of amounts under long-term supply, purchase, or similar agreements or contracts, or if the government requires the disclosure of reserves other than proved, the enterprise shall indicate that the disclosed reserve estimates or amounts do not include figures for the named country or that reserve estimates include reserves other than proved.

Figure 28-1 is taken from FAS 69. It illustrates the format suggested by the FASB for disclosures of oil and gas reserve quantities. An example of such disclosures is provided in Figures 28-2A and 28-2B.

Figure 28-1: Illustrative FAS 69 Reserve Table Disclosure

Reserve Quantity Information*
for the Year Ended December 31, 19XX

	Total		United States		Foreign Geographic Area A		Foreign Geographic Area B		Other Foreign Geographic Areas	
	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas
Proved developed and undeveloped reserves:										
Beginning of year	X	X	X	X	X	X	X	X	X	X
Revisions of previous estimates	X	X	X	X	X	X	X	X	X	X
Improved recovery	X	X	X	X	X	X	X	X	X	X
Purchases of minerals in place	X	X	X	X	X	X	X	X	X	X
Extensions and discoveries	X	X	X	X	X	X	X	X	X	X
Production	(X)	(X)	(X)	(X)	(X)	(X)	(X)	(X)	(X)	(X)
Sales of minerals in place	(X)	(X)	(X)	(X)	(X)	(X)	(X)	(X)	(X)	(X)
End of year	X	X	X	X	X	X	X	X	X	X
Proved developed reserves:										
Beginning of year	X	X	X	X	X	X	X	X	X	X
End of year	X†	X	X	X	X	X	X	X	X	X
Oil and gas applicable to long-term supply agreements with governments or authorities in which the enterprise acts as producer:										
Proved reserves, end of year	X	X			X	X				
Received during the year	X	X			X	X				
Enterprise's proportional interest in reserves of investees accounted for by the equity method—end of year	X	X	X	X	X	X	X	X	X	X

*Oil reserves stated in barrels; gas reserves stated in cubic feet.
†Includes reserves of X barrels attributable to a consolidated subsidiary in which there is an X percent minority interest.

Figure 28-2A: Oil Reserve Table from ExxonMobil's 1999 Annual Report

Crude Oil and Natural Gas Liquids	Consolidated Subsidiaries: United States	Canada	Europe	Asia-Pacific	Other	Total	Non-Consolidated Interests	Total Worldwide
	(millions of barrels)							
Net proved developed and undeveloped reserves								
January 1, 1997	3,194	1,335	1,873	976	1,471	8,849	1,272	10,121
Revisions	(180)	—	52	75	19	(34)	609	575
Purchases	2	1	16	-	—	19	-	19
Sales	(29)	(66)	(11)	(6)	—	(112)	(5)	(117)
Improved recovery	117	8	12	—	—	137	-	137
Extensions and discoveries	81	40	61	21	211	414	38	452
Production	(272)	(88)	(228)	(127)	(119)	(834)	(72)	(906)
December 31, 1997	2,913	1,228	1,875	838	1,582	8,432	1,840	10,272
Revisions	73	23	13	41	241	345	117	462
Purchases	—	-	—	-	—	-	-	—
Sales	(5)	(5)	—	-	—	(10)	(3)	(13)
Improved recovery	17	9	21	—	1	48	85	133
Extensions and discoveries	37	43	27	24	832	963	23	986
Production	(234)	(98)	(228)	(117)	(125)	(802)	(92)	(894)
December 31, 1998	2,804	1,154	1,709	788	2,531	8,983	1,870	10,853
Revisions	95	19	98	23	134	368	25	393
Purchases	-	-	—	-	—	—	—	-
Sales	(3)	-	—	-	—	(3)	(9)	(12)
Improved recovery	7	1	15	-	3	26	72	98
Extensions and discoveries	38	277	174	18	163	720	-	720
Production	(213)	(96)	(232)	(112)	(137)	(790)	(102)	(892)
December 31, 1999	2,748	1,355	1,761	715	2,724	9,304	1,956	11,260
Developed reserves, included above								
At December 31, 1997	2,573	859	582	589	911	5,814	1,286	7,100
At December 31, 1998	2,473	594	884	673	1,089	5,710	1,383	7,093
At December 31, 1999	2,383	608	1,286	615	1,234	5,926	1,333	7,259

Authors' note: In ExxonMobil's Annual Report, the reserve tables are accompanied by narratives that, among other things, (1) define proved oil and gas reserves and acknowledge that the definitions follow SEC regulations and (2) explain that reserves are net, e.g., excluding royalties.

Figure 28-2B: Gas Reserve Table from ExxonMobil's 1999 Annual Report

Natural Gas	Consolidated Subsidiaries: United States	*	Consolidated Subsidiaries: Total	Non-Consolidated Interests	Total Worldwide
			(*billions of cubic feet*)		
Net proved developed and undeveloped reserves					
January 1, 1997	14,549		39,970	18,635	58,605
Revisions	(201)		241	534	775
Purchases	3		70	-	70
Sales	(122)		(395)	(126)	(521)
Improved recovery	23		123	-	123
Extensions and discoveries	476		2,959	1,319	4,278
Production	(1,247)		(3,571)	(674)	(4,245)
December 31, 1997	13,481		39,397	19,688	59,085
Revisions	(643)		1,356	184	1,540
Purchases	-		10	-	10
Sales	(52)		(113)	(34)	(147)
Improved recovery	3		80	34	114
Extensions and discoveries	195		1,422	99	1,521
Production	(1,213)		(3,479)	(638)	(4,117)
December 31, 1998	13,057		38,673	19,333	58,006
Revisions	781		1,665	142	1,807
Purchases	-		-	-	-
Sales	(18)		(19)	-	(19)
Improved recovery	2		121	161	282
Extensions and discoveries	305		812	61	873
Production	(1,126)		(3,499)	(654)	(4,153)
December 31, 1999	13,001		37,753	19,043	56,796
Developed reserves, included above					
At December 31, 1997	10,993		28,640	7,407	36,047
At December 31, 1998	10,690		28,145	7,967	36,112
At December 31, 1999	10,820		27,958	8,643	36,601

**Authors' Note: Consolidated Subsidiaries* columns for Canada, Europe, Asia-Pacific, and Other are not shown in Figure 28-2B due to restrictions of page size.

DISCLOSING CAPITALIZED COSTS OF OIL AND GAS PRODUCING ACTIVITIES

FAS 69, Paragraph 18 (Oi5.168) requires disclosure, as of the end of the year, of the aggregate amount of capitalized costs relating to an enterprise's oil and gas producing activities and the aggregate related accumulated depreciation, depletion, amortization, and valuation allowances.

Paragraph 5 of APB Opinion No. 12, *Omnibus Opinion 1967*, requires disclosure of *balances of major classes of depreciable assets, by nature or function*. Thus, FAS 69, Paragraph 18 notes that separate disclosures of capitalized costs for the following asset categories (listed in FAS 19, Paragraph 11) or for a combination of those categories may often be appropriate:

(1) mineral interests in properties,
(2) wells and related equipment and facilities,
(3) support equipment and facilities, and
(4) uncompleted wells, equipment, and facilities.

FAS 69, Paragraph 19 (Oi5.169) requires that significant capitalized costs of unproved properties be separately reported. Capitalized costs of support equipment and facilities may be disclosed separately or included, as appropriate, with capitalized costs of proved and unproved properties.

Per FAS 69, Paragraph 20 (Oi5.170), if the enterprise's financial statements include investments that are accounted for by the equity method, then the enterprise's share of the investee's net capitalized costs relating to oil and gas producing activities as of the end of the year shall be separately disclosed.

Figure 28-3 shows the format suggested in FAS 69 for disclosing capitalized costs. Figure 28-4 shows an example from ExxonMobil’s 1999 Annual Report. As shown in Figure 28-3, FAS 69 does not require disclosure of capitalized costs by major geographic area, but companies commonly do so (Figure 28-4).

Figure 28-3: Illustrative FAS 69 Disclosure of Capitalized Costs

Capitalized Costs Relating to Oil and Gas Producing Activities at December 31, 19XX

	Total
Unproved oil and gas properties	$X
Proved oil and gas properties	X
	X
Accumulated depreciation, depletion and amortization, and valuation allowances	<X>
Net capitalized costs	$X
Enterprise's share of equity method investee's net capitalized costs	$X

Figure 28-4: Capitalized Costs Disclosures Table from ExxonMobil's 1999 Annual Report

	Consolidated Subsidiaries		Non-Consolidated	Total
Capitalized Costs	United States *	Total	Interests	Worldwide
	(*millions of dollars*)			
As of December 31, 1999				
Property (acreage) costs - Proved	$ 4,606	$ 10,047	$14	$10,061
- Unproved	664	2,779	3	2,782
Total property costs	$5,270	$12,826	$17	$12,843
Producing assets	30,708	79,844	5,294	85,138
Support facilities	795	3,663	145	3,808
Incomplete construction	1,093	6,562	695	7,257
Total capitalized costs	$37,866	$102,895	$6,151	$109,046
Accumulated depreciation and depletion	23,953	59,388	2,872	62,260
Net capitalized costs	$13,913	$43,507	$3,279	$46,786
As of December 31, 1998				
Property (acreage) costs - Proved	$4,718	$9,877	$14	$9,891
- Unproved	683	2,337	15	2,352
Total property costs	$5,401	$12,214	$29	$12,243
Producing assets	29,451	74,857	5,029	79,886
Support facilities	890	3,392	279	3,671
Incomplete construction	1,274	7,907	748	8,655
Total capitalized costs	$37,016	$98,370	$6,085	$104,455
Accumulated depreciation and depletion	22,923	54,872	2,628	57,500
Net capitalized costs	$14,093	$43,498	$3,457	$46,955

**Authors' Note: Consolidated Subsidiaries* columns for Canada, Europe, Asia-Pacific, and Other are not shown in Figure 28-4 due to restrictions of page size. ExxonMobil's table goes beyond FAS 69 disclosure requirements. FAS 69 does not require capitalized costs disclosures by major geographic area.

DISCLOSING COSTS INCURRED IN OIL AND GAS PRODUCING ACTIVITIES

FAS 19 required the disclosure of costs incurred in oil and gas producing activities regardless of whether the costs were capitalized or charged to expense. This requirement of FAS 19 was adopted by the SEC in Reg. S-X Rule 4-10 and is included in almost identical form in Paragraphs 21 through 23 of FAS 69 (Oi5.171 through Oi5.173):

21. Each of the following types of costs for the year shall be disclosed (whether those costs are capitalized or charged to expense at the time they are incurred under the provisions of paragraphs 15-22 of Statement 19):[98]
    a. Property acquisition costs
    b. Exploration costs
    c. Development costs
22. If some or all of those costs are incurred in foreign countries, the amounts shall be disclosed separately for each of the geographic areas for which reserve quantities are disclosed (paragraph 12). If significant costs have been incurred to acquire mineral interests that have proved reserves, those costs shall be disclosed separately from the costs of acquiring unproved properties.
23. If the enterprise's financial statements include investments that are accounted for by the equity method, the enterprise's share of the investees' property acquisition, exploration, and development costs incurred in oil and gas producing activities shall be separately disclosed for the year, in the aggregate and for each geographic area for which reserve quantities are disclosed (paragraph 12).

The FAS 69 proposed format for disclosing costs incurred is shown in Figure 28-5. Figure 28-6, taken from ExxonMobil's 1999 Annual Report, illustrates the disclosure of costs incurred.

[98]FAS 69, footnote 6 states, "As defined in the paragraphs cited, exploration and development costs include depreciation of support equipment and facilities used in those activities and do not include the expenditures to acquire support equipment and facilities."

Figure 28-5: Illustrative FAS 69 Costs Incurred Disclosure

Costs Incurred in Oil and Gas Property Acquisition
Exploration and Development Activities
for the Year Ended December 31 19XX

	Total	United States	Foreign Geographic Area A	Foreign Geographic Area B	Other Foreign Geographic Areas
Acquisition of properties					
Proved	$X	$X	$X	$X	$X
Unproved	X	X	X	X	X
Exploration costs	X	X	X	X	X
Development costs	X	X	X	X	X
Enterprise's share of equity method investee's costs of property acquisition, exploration, and development	X	X	X	X	X

Figure 28-6: Costs Incurred Table from ExxonMobil's 1999 Annual Report

Cost incurred in property acquisition, exploration and development activities		Consolidated Subsidiaries United States *	Consolidated Subsidiaries Total	Non-Consolidated Interests	Total Worldwide
			(*millions of dollars*)		
During 1999					
Property acquisition costs	- Proved	$ -	$ 19	$ -	$ 19
	- Unproved	8	550	-	550
Exploration costs		263	1,340	38	1,378
Development costs		1,263	5,403	409	5,812
Total		$1,534	$7,312	$447	$7,759
During 1998					
Property acquisition costs	- Proved	$ 21	$ 24	$ -	$ 24
	- Unproved	100	291	-	291
Exploration costs		409	1,847	127	1,974
Development costs		1,469	6,423	663	7,086
Total		$1,999	$8,585	$790	$9,375
During 1997					
Property acquisition costs	- Proved	$ 7	$ 123	$ 2	$ 125
	- Unproved	130	217	5	222
Exploration costs		342	1,657	123	1,780
Development costs		1,442	5,937	600	6,537
Total		$1,921	$7,934	$730	$8,664

Authors' Note: *Consolidated Subsidiaries* columns for Canada, Europe, Asia-Pacific, and Other are not shown in Figure 28-6 due to restrictions of page size.

DISCLOSING RESULTS OF OPERATIONS FOR OIL AND GAS PRODUCING ACTIVITIES

A new requirement contained in FAS 69 (and Oi5.174 through Oi5.179) is for disclosure of historical results of operations for oil and gas producing activities, by major geographic area:

> 24. The results of operations for oil and gas producing activities shall be disclosed for the year. That information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed (paragraph 12). The following information relating to those activities shall be presented:[99]
>
> a. Revenues
> b. Production (lifting costs)
> c. Exploration expenses[100]
> d. Depreciation, depletion, and amortization, and valuation provisions
> e. Income tax expense
> f. Results of operations for oil and gas producing activities (excluding corporate overhead and interest costs)
>
> 25. Revenues shall include sales to unaffiliated enterprises and sales or transfers to the enterprise's other operations (for example, refineries or chemical plants). Sales to unaffiliated enterprises and sales or transfers to the enterprise's other operations shall be disclosed separately. Revenues shall include sales to unaffiliated enterprises attributable to net working interests, royalty interests, oil payment interests, and net profits interests of the reporting enterprise. Sales or transfers to the enterprises' other operations shall be based on market prices determined at the point of delivery from the producing unit. Those market prices shall represent

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[99]A company with only E&P operations and in only one country should already provide this information in its income statement and should not need to provide duplicate supplemental information. FAS 69, footnote 7, states: "If oil and gas producing activities represent substantially all of the business activities of the producing enterprise and those oil and gas activities are located substantially in a single geographic area, the information required by paragraphs 24-29 of the Statement need not be disclosed if that information is provided elsewhere in the financial statements."

[100]FAS 69, footnote 8, provides: "Generally, only enterprises utilizing the successful efforts accounting method will have exploration expenses to disclose, since enterprises utilizing the full cost accounting method generally capitalize all exploration costs when incurred and subsequently reflect those costs in the determination of earnings through depreciation, depletion, and amortization, and in the valuation provisions."

prices equivalent to those that could be obtained in an arm's-length transaction. Production or severance taxes shall not be deducted in determining gross revenues, but rather shall be included as part of production costs. Royalty payments and net profits disbursements shall be excluded from gross revenues.

26. Income taxes shall be computed using the statutory tax rate for the period, applied to revenues less production (lifting) costs, exploration expenses, depreciation, depletion, and amortization, and valuation provisions. Calculation of income tax expense shall reflect [tax deductions],[101] tax credits and allowances relating to the oil and gas producing activities that are reflected in the enterprise's consolidated income tax expense for the period.

27. Results of operations for oil and gas producing activities are defined as revenues less production (lifting) costs, exploration expenses, depreciation, depletion, and amortization, valuation provisions, and income tax expenses. General corporate overhead and interest costs[102] shall not be deducted in computing the results of operations for an enterprise's oil and gas producing activities. However, some expenses incurred at an enterprise's central administrative office may not be general corporate expenses, but rather may be operating expenses of oil and gas producing activities, and therefore should be reported as such. The nature of an expense rather than the location of its incurrence shall determine whether it is an operating expense. Only those expenses identified by their nature as operating expenses shall be allocated as operating expenses in computing the results of operations for oil and gas producing activities.

28. The amounts disclosed in conformity with paragraphs 24-27 shall include an enterprise's interests in proved oil and gas reserves (paragraph 10) and in oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the enterprise participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (paragraph 13).

29. If the enterprise's financial statements include investments that are accounted for by the equity method, the investee's results of operations for oil and gas producing activities shall not be included in the enterprise's results of operations for oil and gas producing activities.

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[101]Amended by FAS 109, Paragraph 288 to replace the outdated term *permanent differences* with *tax deductions*.

[102]FAS 69, footnote 9, states: "The disposition of interest costs that have been capitalized as part of the cost of acquiring qualifying assets used in oil and gas producing activities shall be the same as that of other components of those assets' costs."

However, the enterprise's share of the investee's results of operations for oil and gas producing activities shall be separately disclosed for the year, in the aggregate and by each geographic area for which reserve quantities are disclosed (paragraph 12).

Figure 28-7 shows the illustrative FAS 69 Results of Operations Disclosure. Figure 28-8 shows a corresponding excerpt from ExxonMobil's 1999 Annual Report disclosure.

In addition to the above disclosure requirements, FAS 69 also requires disclosure of *a standardized measure of discounted future net cash flows* from proved oil and gas reserves. The complex calculations required for this disclosure are discussed in Chapter Twenty-Nine.

Figure 28-7: Illustrative FAS 69 Results of Operations Disclosure

Results of Operations for Producing Activities
for the Year Ended December 31, 19XX

	Total	United States	Foreign Geographic Area A	Foreign Geographic Area B	Other Foreign Geographic Areas
Revenues					
Sales	$X	$X	$X	$X	$X
Transfers	X	X	X	X	X
Total	X	X	X	X	X
Production costs	(X)	(X)	(X)	(X)	(X)
Exploration expenses	(X)	(X)	(X)	(X)	(X)
Depreciation, depletion, and amortization, and valuation provisions	(X)	(X)	(X)	(X)	(X)
	X	X	X	X	X
Income tax expenses	(X)	(X)	(X)	(X)	(X)
Results of operations for producing activities (excluding corporate overhead and interest costs)	$X	$X	$X	$X	$X
Enterprise's share of equity method investees' results of operations for producing activities.	$X	$X	$X	$X	$X

Figure 28-8: Excerpt of Results of Operations Disclosure from ExxonMobil's 1999 Annual Report

Results of Operations	United States	** Total	Non-Consolidated Interests	Total Worldwide
1999 - Revenue				
Sales to third parties	$ 2,419	$ 8,982	$ 2,123	$ 11,105
Transfers	3,237	10,203	867	11,070
	$ 5,656	$ 19,185	$ 2,990	$ 22,175
Production costs excluding taxes	1,347	4,467	617	5,084
Exploration expenses	232	1,246	29	1,275
Depreciation and depletion	1,260	4,847	443	5,290
Taxes other than income	425	1,014	591	1,605
Related income tax	893	3,124	546	3,670
Results of producing activities	$ 1,499	$ 4,487	$ 764	$ 5,251
Other earnings*	42	452	183	635
Total earnings	$ 1,541	$ 4,939	$ 947	$ 5,886

*Includes earnings from transportation operations, tar sands operations, LNG technical services agreements, other non-operating activities and adjustments for minority interests.

***Authors' Note: Consolidated Subsidiaries* columns for Canada, Europe, Asia-Pacific, and Other are not shown in Figure 28-8 due to restrictions of page size. Results of operations for 1998 and 1997 appearing in ExxonMobil's table are also omitted for Figure 28-8.

SPECIAL DISCLOSURES FOR COMPANIES USING FULL COST

Companies, whether publicly held or not, using the Reg. S-X Rule 4-10 full cost method are subject to various additional disclosure requirements.

DISCLOSING FULL COST AMORTIZATION PER UNIT OF PRODUCTION

Subparagraph (c)(7)(i) of Reg. S-X Rule 4-10 requires special disclosure of the amortization per unit of production for each cost center:

> (i) For each cost center for each year that an income statement is required, disclose the total amount of amortization expense (per equivalent physical unit of production if amortization is computed on the basis of physical units or per dollar of gross revenue from production if amortization is computed on the basis of gross revenue).

An example of this disclosure is shown in Figure 28-9.

Figure 28-9: Example of Amortization per Unit of Production

Contained in the Supplemental Oil and Gas Disclosures in Apache Corporation's 1999 Annual Report:

	United States	Canada	Egypt	*	Total
1999 (in thousands)					
Oil and gas production revenues	$699,039	$86,901	$235,935		$1,142,336
Operating costs:					
Depreciation, depletion, and Amortization	280,033	33,671	74,695		429,660
Lease operating expenses	125,452	18,095	26,444		191,161
Production taxes	23,212	--	--		28,107
Income tax	101,378	15,677	64,702		200,878
	530,075	67,443	165,841		849,806
Results of operations	$168,964	$19,458	$70,094		$ 292,530
Amortization rate per boe	$ 6.10	$ 4.54	$ 5.25		$ 5.57

**Authors' Note:* For brevity, not shown are the 1999 columns for Australia and the Ivory Coast and the 1998 and 1997 tables.

DISCLOSING UNEVALUATED COSTS UNDER FULL COST ACCOUNTING

As pointed out in Chapter Nineteen, special disclosures related to unevaluated costs that have been excluded from amortization are also required. This requirement is found in Paragraph (c)(7)(ii) of Reg. S-X Rule 4-10:

> (ii) State separately on the face of the balance sheet the aggregate of the capitalized costs of unproved properties and major development projects that are excluded, in accordance with paragraph (i)(3) of this section, from the capitalized costs being amortized. Provide a description in the notes to the financial statements of the current status of the significant properties or projects involved, including the anticipated timing of the inclusion of the costs in the amortization computation. Present a table that shows, by category of cost, (A) the total costs excluded as of the

> most recent fiscal year; and (B) the amounts of such excluded costs, incurred (1) in each of the three most recent fiscal years and (2) in the aggregate for any earlier fiscal years in which the costs were incurred. Categories of cost to be disclosed include acquisition costs, exploration costs, development costs in the case of significant development projects and capitalized interest.

Sometimes, the costs excluded from amortization are separately disclosed in a financial statement note rather than on the face of the balance sheet. Below is an example from Anadarko Petroleum Corporation's 1999 Annual Report:

> Properties and Equipment – Oil and gas properties include costs of $323,019,000 and $353,647,000 at December 31, 1999 and 1998, respectively, which were excluded from capitalized costs being amortized. These amounts represent costs associated with unevaluated properties and major development projects. Anadarko excludes all costs on a country-by-country basis until proved reserves are found or until it is determined that the costs are impaired. All excluded costs are reviewed quarterly to determine if impairment has occurred. . . .

DISCLOSING CEILING TEST RESULTS

Per Reg. S-X Rule 4-10(c)(4)(ii), any write-down expense for net capitalized costs in excess of the full cost ceiling shall be separately disclosed. If such an excess is not charged to expense because of certain subsequent events, as discussed in Chapter Nineteen, then the company should disclose that an excess existed and disclose why the excess was not charged to expense per SAB Topic 12D, Item 3(b). Note that the SAB does not specifically require that the amount of the excess be disclosed.

An example of the write-down disclosure is found in Newfield Exploration Company's 1999 Annual Report. The financial statement note disclosure reads as follows:

> The Company uses the full cost method of accounting. . . . For each cost center, the net capitalized costs of oil and gas properties are limited to the lower of unamortized cost or the cost center ceiling, defined as the sum of the present value (10% per annum discount rate) of estimated future net revenues from proved reserves, based on year-end oil and gas prices; plus the cost of properties not being amortized, if any; plus the

> lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any; less related income tax effects. As required by these rules, a non-cash writedown of oil and gas properties of $105.0 million (resulting in a charge to earnings of $68.3 million after-tax) was recognized at December 31, 1998. The writedown was primarily attributable to the lower prices for both oil and natural gas at December 31, 1998.

OTHER SEC DISCLOSURE REQUIREMENTS

In addition to the supplemental disclosures discussed above, the SEC requires a number of other disclosures that are not related to the financial statements but are contained in the forepart of securities registration statements and of Form 10-K Annual Reports filed with the SEC. These requirements are found in the SEC's Regulation S-K and in *Guide 2, Disclosure of Oil and Gas Operations*. These include the following:

For each of the last three fiscal years:

1. Average sales price and production cost per unit.
2. Total net productive and dry wells drilled, broken down by exploratory wells and development wells drilled, by appropriate geographic area.

For the current date or end of the latest fiscal year:

1. Total gross and net productive oil and gas wells.
2. Total gross and net developed acreage by FAS 69 major geographic area.
3. Total gross and net undeveloped acreage by appropriate geographic area and, if material, minimum remaining terms of leases and concessions.
4. Number of wells in progress, gross and net, waterfloods, pressure maintenance operations, etc., by appropriate geographic area.
5. Information about obligations to provide fixed quantities of oil and gas in the future under existing contracts.

Chapter Twenty-Nine

VALUE-BASED DISCLOSURES

As explained in Chapter Twenty-Eight, RRA value disclosures required by the SEC in 1978 were replaced with disclosures required by FAS 69, issued in late 1982. FAS 69 required, among other things, disclosure of "a standardized measure of discounted future net cash flows relating to proved oil and gas reserve quantities." The term is often called simply *the standardized measure*, or *SMOG*.[103] SMOG's calculation is almost identical to the calculation required by the SEC under RRA disclosures, except that SMOG's calculation considers future income taxes, whereas RRA's did not.

DISCLOSURE RULES

The SMOG measure requirements are specified in Paragraphs 30 through 32 of FAS 69, reproduced below, and in Oi5.180 through Oi5.182 on pages 32 through 34 of Appendix 3.

> 30. A standardized measure of discounted future net cash flows relating to an enterprise's interests in (a) proved oil and gas reserves (paragraph 10) and (b) oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the enterprise participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (paragraph 13) shall be disclosed as of the end of the year. The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes. The following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraph 12:

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[103] The term *SMOG* is a popular acronym for standardized measure of oil and gas. It was coined by a major oil company's treasurer about the time FAS 69 was adopted. FAS 69 notes that SMOG is not fair value, only a rough surrogate for fair market value, but the industry feared the public and analysts would mistakenly view SMOG as fair value. In a sense, SMOG presents a rather hazy picture of fair value, much like smog in the air obscures one's view. Hence, the term seemed an appropriate acronym for this required disclosure.

a. *Future cash inflows.* These shall be computed by applying year-end prices of oil and gas relating to the enterprise's proved reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.

b. *Future development and production costs.* These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.

c. *Future income tax expenses.* These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pre-tax net cash flows relating to the enterprise's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to [tax deductions] and tax credits and allowances relating to the enterprise's proved oil and gas reserves.[104]

d. *Future net cash flows.* These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.

e. *Discount.* This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of future net cash flows relating to proved oil and gas reserves.

f. *Standardized measure of discounted future net cash flows.* This amount is the future net cash flows less the computed discount.

31. If a significant portion of the economic interest in the consolidated standardized measure of discounted future net cash flows reported is attributable to a consolidated subsidiary(ies) in which there is a significant minority interest, that fact and the approximate portion shall be disclosed.

32. If the financial statements include investments that are accounted for by the equity method, the investees' standardized measure of discounted future net cash flows relating to proved oil and gas reserves shall not be included in the disclosure of the enterprise's standardized measure. However, the enterprise's share of the investees' standardized measure of discounted future net cash flows shall be separately disclosed for the year, in the aggregate and by each geologic area for which quantities are disclosed (paragraph 12).

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[104]FAS 109 amended FAS 69 to replace the outdated term *permanent differences* with the term *tax deductions*.

The format suggested in FAS 69 for the standardized measure disclosure is shown on the following page.

In addition to the end-of-year disclosure of present value, FAS 69 also calls for disclosure of (1) the aggregate SMOG change for the year and (2) significant reasons for the change in SMOG value from the beginning of the year to the end of the year. FAS 69, Paragraph 33 (Oi5.183) lists major reasons that may exist for SMOG changes and calls for their individual disclosures if the amounts are significant:

> 33. The aggregate change in the standardized measure of discounted future net cash flows shall be disclosed for the year. If individually significant, the following sources of change shall be presented separately:
>
> a. Net change in sales and transfer prices and in production (lifting) costs related to future production
> b. Changes in estimated future development costs
> c. Sales and transfers of oil and gas produced during the period
> d. Net change due to extensions, discoveries, and improved recovery
> e. Net change due to purchases and sales of minerals in place
> f. Net change due to revisions in quantity estimates
> g. Previously estimated development costs incurred during the period
> h. Accretion of discount
> i. Other—unspecified
> j. Net change in income taxes
>
> In computing the amounts under each of the above categories, the effects of changes in prices and costs shall be computed before the effects of changes in quantities. As a result, changes in quantities shall be stated at year-end prices and costs. The change in computed income taxes shall reflect the effect of income taxes incurred during the period as well as the change in future income tax expenses. Therefore, all changes except income taxes shall be reported pre-tax.

Figure 29-1: First Half of Illustration 5 of FAS 69

STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOWS AND CHANGES THEREIN RELATING TO PROVED OIL RESERVES AT DECEMBER 31, 19XX

	Total	United States	Foreign Geographic Area A	Foreign Geographic Area B	Other Foreign Geographic Areas
Future cash inflows*	$X	$X	$X	$X	$X
Future production and Development costs*	(X)	(X)	(X)	(X)	(X)
Future income tax expenses*	(X)	(X)	(X)	(X)	(X)
Future net cash flows	X	X	X	X	X
10% annual discount for estimated Timing of cash flows	(X)	(X)	(X)	(X)	(X)
Standardized measure of discounted Future net cash flows	$X**	$X	$X	$X	$X
Enterprise's share of equity method Investees' standardized measure of Discounted future net cash flows	$X	$X	$X	$X	$X

* Future net cash flows were computed using year-end prices and costs, and year-end statutory tax rates (adjusted for [tax deductions]) that relate to existing proved oil and gas reserves in which the enterprise has mineral interests, including those mineral interests related to long-term supply agreements with governments for which the enterprise serves as the producer of the reserves.

** Includes $X attributable to a consolidated subsidiary in which there is an X percent minority interest.

The format suggested in FAS 69 for the disclosure of reasons for changes is shown in Figure 29-2 below.

Figure 29-2: Second Half of Illustration 5 of FAS 69

The following are the principal sources of change in the standardized measure of discounted future net cash flows during 19XX:

Sales and transfers of oil and gas produced, net of Production costs	$ (X)
Net changes in prices and production costs	X
Extensions, discoveries, and improved recovery, Less related costs	X
Development costs incurred during the period	X
Revisions of previous quantity estimates	X
Accretion of discount	X
Net change in income taxes	X
Other	X

Authors' Note: The above FAS 69 illustration does not list all of the sources of change noted in Paragraph 33, nor does it show the aggregate change as required in Paragraph 33. Figure 29-24 at the end of this chapter includes the items omitted above. The SMOG change for development costs incurred during the period is always a positive change, as shown above; not a negative change, as shown in Illustration 5 of FAS 69.

SMOG COMPUTATION EXAMPLE

The next several pages illustrate how SMOG and SMOG changes may be computed. In this example, a company has proved reserves as of December 31, 1999, in only one field, Field No. 1. During 2000, the company discovers proved reserves in a second field, Field No. 2. The example first computes Field No. 1's SMOG as of 12/31/99, then as of 12/31/00. Next, individual components of Field No. 1's SMOG changes for 2000 are computed. The example then computes Field No. 2's SMOG as of 12/31/00 and Field No. 2's SMOG changes for 2000 arising from the field's discovery and production. Finally, the SMOG and SMOG change computations by field are combined to determine the company's aggregate SMOG as of 12/31/00 and its SMOG changes for 2000.

COMPUTING SMOG

Some companies calculate the standardized measure and changes therein in the aggregate or by major geographical area, rather than by field, because field-by-field computations are often impractical. Calculations in the aggregate are generally less precise than by field but can employ the same calculation concepts illustrated in this field-by-field example.

Assume the following information relating to the company's ownership in reserves in Field No. 1 on December 31, 1999, shown in Figure 29-3.

Figure 29-3: Field No. 1 Assumptions as of 12/31/99

	2000	2001	2002	2003	2004	Total
Production (bbls)	30,000	22,500	15,000	7,500	3,750	78,750
Revenue at $20/bbl	$600,000	$450,000	$300,000	$150,000	$75,000	$1,575,000
Production costs	$300,000	$225,000	$150,000	$75,000	$37,500	$787,500
Development costs	$100,000					$100,000
Income taxes	$70,200	$58,650	$39,100	$19,550	$9,775	$197,275

Computation of Future Income Taxes

For this example, future income taxes are simply given. However, actual SMOG disclosures employ two approaches to compute the future income taxes applicable to the production of proved reserves. The first method is a year-by-year calculation in which the projected revenues for each year, projected operating expenses, depreciation, depletion, and other factors are considered in arriving at that year's tax outflow. The second method of computing the tax liability is the *short-cut* approach, which is a lump-sum calculation rather than a year-by-year calculation.[105] FAS 69's illustration of the standardized measure of discounted future net cash flows (shown in Figure 29-1) suggests that the effects of income taxes on future net cash flows from production of proved reserves are to be computed for each future year. How can after-tax future cash flows be discounted at ten percent per year if taxes are not computed year by year? This year-by-year approach seems to be required by Paragraph 30 of FAS 69 (Oi5.180), which states:

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[105]See Chapter Nineteen for examples of how to apply a short-cut method in calculating income tax effects for the full cost ceiling test.

> *Future Income Tax Expenses.* These expenses shall be computed by applying the appropriate year-end statutory rates, with consideration of future tax rates already legislated, to the enterprise's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expense shall give effect to [tax deductions] and tax credits and allowances relating to the enterprise's proved oil and gas reserves.

Further, FAS 69, Paragraph 33 (Oi5.183) discusses changes in *future* income tax expense. In January 1987, the SEC staff expressed informally that income taxes for SMOG should be calculated year by year rather than using a short-cut basis as allowed for the ceiling test.[106]

However, many companies still use a *short-cut* method to compute SMOG income taxes. The *1999 PricewaterhouseCoopers Survey* found that in calculating SMOG, only 46 percent of the 41 responding companies calculate income taxes on a year-by-year basis and 54 percent use a short-cut method.

Computation of Future Net Cash Flows

Figure 29-1's illustration of the SMOG disclosure shows a line for *future net cash flows* computed for this example in Figure 29-4. Future cash inflows (i.e., future revenues) less future production costs and future development costs equal future pre-tax net cash flows (often called by its old RRA term, *future net revenues*). Future net revenues less future income tax expense equal future net cash flows.

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[106]January 1987 meeting of selected Big 8 accounting firm oil and gas partners with SEC staff in conjunction with the AICPA's SEC conference.

Figure 29-4: Schedule of Future Net Cash Flows, Field No. 1, as of 12/31/99

	2000	2001	2002	2003	2004	Total
Revenue	$600,000	$450,000	$300,000	$150,000	$75,000	$1,575,000
Production costs	(300,000)	(225,000)	(150,000)	(75,000)	(37,500)	(787,500)
Development costs	(100,000)	0	0	0	0	(100,000)
Future net revenues	200,000	225,000	150,000	75,000	37,500	687,500
Income tax expense	(70,200)	(58,650)	(39,100)	(19,550)	(9,775)	(197,275)
Future net cash flows	$129,800	$166,350	$110,900	$ 55,450	$27,725	$ 490,225

Computation of the Present Value of Future Net Cash Flows

FAS 69 requires that future net cash flows be discounted at a standard rate of ten percent per year. Reference to a *present value of 1* table shows the following *present value of 1* factors (PV factors) based on the assumption that the first year's cash inflow is received, on average, six months from the date of the standardized measure. This is commonly known as the mid-year convention.

Figure 29-5: Present Value of 1 Factors[107]

Year	PV Factor
1	.9535
2	.8668
3	.7880
4	.7164
5	.6512

Applying the PV factors from Figure 29-5 to the future net cash flows in Figure 29-4, the total present value of proved reserves (i.e., SMOG) as of 12/31/99 for Field No. 1 is $413,124, as shown in Figure 29-6.

[107]The formula for computing the present value factor for a ten percent discount, assuming the mid-year convention, is 110 percent raised to the negative power of (the year less a half year). For example, for the second year, it is 110%^ -1.5, which equals 0.8668.

Figure 29-6: Computation of SMOG, Field No. 1, as of 12/31/99

	2000	2001	2002	2003	2004	Total
Future net cash Flows (Fig. 29-4)	$129,800	$166,350	$110,900	$55,450	$27,725	$490,225
X Present value factors	x .9535	x .8668	x .7880	x .7164	x .6512	-
SMOG	$123,764	$144,192	$ 87,389	$39,724	$18,055	$413,124

Computation of the Discount for Estimated Timing of Cash Flows

FAS 69 calls for disclosure of the amount of the discount resulting from the above process. This discount amount is found by deducting the SMOG value from the undiscounted future net cash flows, as shown in Figure 29-7.

Figure 29-7: Computation of the Discount as of 12/31/98

Total future net cash flows, Fig. 29-6	$490,225
Less SMOG value, Fig. 29-6	(413,124)
Discount	$ 77,101

Statement of Standardized Measure

Using the FAS 69 format, the standardized measure data relating to Field No. 1 as of December 31, 1999, would be presented as follows:

Figure 29-8: Standardized Measure of Discounted Future Net Cash Flows as of 12/31/99

Future cash inflows	$1,575,000
Future production costs	(787,500)
Future development costs	(100,000)
Future income tax expenses	(197,275)
Future net cash flows	490,225
10% annual discount for estimated timing of cash flows	(77,101)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$ 413,124

COMPUTING SMOG CHANGES

In order to demonstrate the calculation of individual factors leading to changes in the standardized measure of discounted present value of reserves in Field No. 1 during the year 2000, it is first necessary to compute the standardized measure as of December 31, 2000.

Figure 29-9: Field No. 1 Assumptions for the Year 2000 and as of 12/31/00

Data for 2000			
Production for 2000		27,000	bbls
Revenues		$558,000	
Production expenses		$284,000	
Previously estimated development costs incurred		$102,000	
Data as of 12/31/00			
Proved reserves and production schedule	2001-	18,000	bbls
	2002-	12,000	bbls
	2003 -	6,000	bbls
	2004 -	3,000	bbls
	Total -	39,000	bbls
Price per barrel at 12/31/00		$21.33	
Production expenses per barrel at 12/31/00[108]		$10.33	
Future income taxes are set forth in Figure 29-10.			

Based on the above data, the standardized measure for Field No. 1 on December 31, 2000, is $280,949, as computed in Figure 29-10.

[108]For simplicity, the chapter's examples express future production expenses in terms of expense per barrel. In actual cases, production cost rates are primarily *fixed*, expressed as lease operating expenses per well per month; and some rates, such as severance tax rates, are *variable* expressed as a percentage of sales or cost per unit of production.

Figure 29-10: Computation of Standardized Measure, Field No. 1, as of 12/31/00

	2001	2002	2003	2004	Total
Future cash inflows	$383,940	$255,960	$127,980	$63,990	$831,870
Future production costs	(185,940)	(123,960)	(61,980)	(30,990)	(402,870)
Future income tax expense	(51,170)	(34,114)	(17,057)	(8,528)	(110,869)
Future net cash flow	146,830	97,886	48,943	24,472	318,131
x Present value factors	x .9535	x .8668	x .7880	x .7164	-
Standardized measure	$140,002	$ 84,848	$ 38,567	$17,532	$280,949

The aggregate change for the year 2000 in Field No. 1's standardized measure is a $132,175 decrease, computed as the 12/31/00 standardized measure of $280,949 less the 12/31/99 standardized measure of $413,124.

Analysis of Reasons for Changes in Value

The major reasons SMOG changes in 2000 are as follows:

1) Accretion of discount
2) Sale of oil and gas produced, net of production costs
3) Development cost changes
4) Revisions of previous quantity estimates
5) Net changes in prices and production costs
6) Changes in estimated future income taxes
7) Timing and other

Each of these factors is analyzed in the following pages.

Accretion of Discount

A basic feature of the FASB's standardized measure is the discounting of future cash flows at a standard rate of ten percent per year. Thus, with all other factors remaining constant, the value of reserves in the ground increases with the passage of time by ten percent per year. Because FAS 69, Paragraph 33 requires that all changes except income taxes be reported pre-tax, the accretion is based on pre-tax SMOG value as of the beginning of the year. Accretion can be calculated simplistically as ten percent of pre-tax SMOG value as of 12/31/99, as shown in Figure 29-11, Step 3.

Figure 29-11: Calculation of Pre-Tax SMOG Value

	2000	2001	2002	2003	2004	Total
Future income taxes	$70,200	$58,650	$39,100	$19,550	$9,775	$197,275
x PV Factors	x .9535	x .8668	x .7880	x .7164	x .6512	-
Present value of taxes	$66,936	$50,838	$30,811	$14,006	$6,365	$168,956

Step 2: Calculate pre-tax SMOG value as of 12/31/99.	
SMOG value as of 12/31/99	$413,124
Add back discounted income taxes as of 12/31/99	168,956
Pre-tax SMOG value as of 12/31/99	$582,080
Step 3: Calculate accretion as 10% of pre-tax SMOG.	
Pre-tax present value at 12/31/99 per Figure 29-12	$582,080
x 10% discount rate	x 10%
Accretion (increase) for 2000	$ 58,208

Figure 29-11 reflects a common, simple approach to calculating the SMOG change attributable to accretion.[109] Arguably, the actual change is slightly less than ten percent of the year's beginning pre-tax present value (or *pre-tax SMOG*), as reflected in Figure 29-12. The reason is that the first year's cash flow accretion is only as great as its discount as of the beginning of the year, or approximately five percent, not ten percent, on the assumption that its cash flow is received on average in the middle of that year.

[109]The *PricewaterhouseCoopers 1999 Survey* found that 28 of 39 respondents (72 percent) calculated accretion as ten percent of beginning pre-tax SMOG, and 7 of 39 (18 percent) used ten percent of after-tax SMOG. This after-tax approach is contrary to FAS 69, Paragraph 33. Only three respondents used the approach illustrated in Figure 29-12, even though that approach is the most precise of the three. One respondent used another unspecified approach.

Figure 29-12: An Acceptable Variation in Calculating the 2000 SMOG Change Due to Accretion

	2000	2001	2002	2003	2004	Total
Future net revenues						
at 12/31/99 (Fig28-4)	$200,000	$225,000	$150,000	$75,000	$37,500	$687,500
x 12/31/99 pv factors (Fig. 29-6)	0.9535	0.8668	0.7880	0.7164	0.6512	-
= 12/31/99 pre-tax SMOG [A]	190,700	195,030	118,200	53,730	24,420	582,080
Future net revenues (above)	200,000	225,000	150,000	75,000	37,500	687,500
x 12/31/00 pv factors	1.0000	0.9535	0.8668	0.7880	0.7164	-
= Accreted pre-tax SMOG [B]	200,000	214,538	130,020	59,100	26,865	630,523
Accretion [B] – [A]	$ 9,300	$ 19,508	$ 11,820	$ 5,370	$ 2,445	$ 48,443
Accretion as a % of [A]	4.9%	10.0%	10.0%	10.0%	10.0%	8.3%

As will be seen in Figure 29-18, the $58,208 computed in Figure 29-11 (*Simple Accretion*) significantly increases SMOG change due to *other* whereas the $48,443 in Figure 29-12 (*Precise Accretion*) does not.

Sale of Oil and Gas Produced, Net of Production Costs

The production and sale of reserves obviously decreases the value of reserves in the ground and decreases SMOG. The resulting 2000 change in SMOG could be measured in two ways: (1) the $274,000 of actual 2000 revenues of $558,000 less actual production expenses of $284,000, given in Figure 29-9 or (2) the $300,000 of projected 2000 revenues of $600,000 less production expenses of $300,000, reflected in 12/31/99 SMOG per Figure 29-4. The first measure, employing actual sales and production expenses, appears to be universally used and is less confusing, since actual sales and expenses are already disclosed to financial statement users, and the old projection for 2000 activity is not.

Figure 29-13: SMOG Change from 2000 Sales of Oil Produced, Net of Production Costs, Field No. 1

Actual 2000 sales	$558,000
Less actual 2000 production expenses	(284,000)
2000 net (a decrease in SMOG)	$274,000

The difference between actual and projected amounts is not simply classified as *other* in the SMOG change table, because actual production quantities are considered in computing the SMOG effect of reserve revisions (Figure 29-15) and because in some approaches actual operating cash flow is considered in calculating the SMOG effect of price and cost rate changes [Figure 29-19, note (f)].

Development Cost Changes

FAS 69, Paragraph 33 calls for disclosure of SMOG change attributable to (1) "previously estimated development costs incurred during the period" and (2) "changes in estimated future development costs."

The 12/31/99 SMOG reflected $100,000 of future development costs for 2000 (Figure 29-3). Actual costs were $102,000 (Figure 29-9). The related SMOG increase in 2000 attributable to development cost changes could be presented in two ways, as shown in Figure 29-14.

Figure 29-14: SMOG Changes for Development Cost Changes, Field No. 1, 2000—Two Approaches

• $100,000	for previously estimated development costs incurred during the period,
	or
• $102,000	for actual development costs incurred, and
($2,000)	for changes in estimated future development costs.

Both approaches have merit. However, users of the second approach need to be careful not to include incurred development costs that did not relate to proved undeveloped locations at the beginning of the year. Otherwise, both the SMOG increase for incurred costs and the SMOG decrease (in this example) for changes in estimated future development costs might be significantly overstated.

Revisions of Previous Quantity Estimates

FAS 69, Paragraph 33 requires that the SMOG change due to quantity revisions be based on year-end prices and costs. One approach to this calculation consists of three steps:

(1) Compute the quantity revision.
(2) Compute its effect on *undiscounted* value based on end-of-year prices and costs.

(3) Compute the present value effect by multiplying the undiscounted change by the ratio of (a) present value of future operating cash flow (i.e., future gross revenues minus future production costs) to (b) undiscounted future operating cash flow.

These steps are applied in Figure 29-15 to the data for Field No. 1 for 2000.

Figure 29-15: Net Change for Quantity Revisions

(1) Compute the quantity revision:

12/31/00 estimated reserves [*A*]	39,000	bbls
Proved reserves estimated as of 12/31/99	78,750	bbls
Less 2000 quantities actually sold	(27,000)	bbls
12/31/99 estimated reserves not sold in '00 [*B*]	51,750	bbls
Reserve revision decrease [*A* - *B*]	(12,750)	bbls

(2) Compute the effect on undiscounted value:

Per Figure 29-9:

Undiscounted revenue per barrel, 12/31/00 = $21.33

Undiscounted production cost per barrel, 12/31/00 = $10.33

-12,750 bbls x ($21.33/bbl – $10.33/bbl) = $140,250 decrease

(3) Compute the present value effect:

A. Compute the ratio of discounted to undiscounted future operating cash flow as of 12/31/00:

	2001	2002	2003	2004	Total
Future cash inflow	$383,940	$255,960	$127,980	$63,990	$831,870
Future production costs	(185,940)	(123,960)	(61,980)	(30,990)	(402,870)
Future operating cash flow	198,000	132,000	66,000	33,000	$429,000
x Discount factors	x .9535	x .8668	x .7880	x .7164	
Discounted	$188,793	$114,418	$52,008	$23,641	$378,860
Ratio of discounted to undiscounted future operating cash flow					0.88312

B. Multiply the computed ratio by the effect on undiscounted value:

0.88312 x $140,250 = $123,858 decrease in SMOG value

Net Changes in Prices and Production Costs

The net change in pre-tax SMOG due to changes in prices and production costs is similar to price variance in traditional cost accounting variance analysis. Consider a simple example. A 12/31/99 value (V_{old}) equals the product of the 12/31/99 reserve quantity (Q_{old}) times a net price (P_{old}) where net price is the discounted operating cash flow per boe as of 12/31/99. The 12/31/00 value (V_{new}) = Q_{new} x $P_{new.}$ To restate with examples:

V_{old} = Q_{old} x P_{old} Example: $108,000 = 12,000 bbls x $ 9/bbl

V_{new} = Q_{new} x P_{new} Example: $100,000 = 10,000 bbls x $10/bbl

The Q_{old} of 12,000 barrels equates to a 12/31/99 reserve estimate excluding 2000 production because the SMOG change due to 2000 production is separately disclosed.

When applicable, Q_{old} would also exclude any reserves attributable to mineral interests sold during the year, since SMOG change due to mineral interest sales is separately disclosed. For similar reasons, Q_{new} would exclude any reserve additions attributable to proved property purchases or to new extensions, discoveries, or improved recoveries. These factors are not relevant to the simple example above or to the Field No. 1 example, but are typical when a company computes its SMOG changes in the aggregate rather than by field.

As required by FAS 69, Paragraph 33, the quantity variance is (Q_{new} - Q_{old}) x P_{new} , which for this example is (10,000 - 12,000) x $10, which calculates to a negative $20,000. This quantity variance formula is similar to the computations in Figure 29-15. The price variance is (P_{new} - P_{old}) x Q_{old} , which for this example is ($10 - $9) x 12,000, which calculates to $12,000. The sum of the -$20,000 quantity variance and the $12,000 price variance equals the net $8,000 decrease in value. Thus, the basic formula is that the SMOG change attributable to price and cost rate changes is a *price variance* equal to the change in net price per boe times the *old quantity*, i.e., estimated reserves at the beginning of the year, excluding the current year's production.

If the price variance formula used Q_{new}, rather than Q_{old}, then the price variance would be incorrectly calculated as $10,000, which when added to the -$20,000 quantity variance would not equal the net $8,000 decrease in value.

Having established the basic formula for calculating the SMOG change due to price and cost changes, one approach to making this calculation for Field No. 1 is to follow the four steps below:

(1) Compute the units included in the estimate of beginning reserves that were not sold during the year.
(2) Compute the net change in price and costs per unit.
(3) Multiply (1) by (2) to determine the undiscounted net change from price and cost factors.
(4) Multiply the undiscounted net change computed in step (3) by the year-end ratio of (a) present value of future operating cash flow to (b) undiscounted future operating cash flow.

This approach is merely one of several that might be followed to meet the FAS 69, Paragraph 33 requirement that the "effects of changes in prices and cost rates shall be computed before the effects of changes in quantities" whereby quantity changes are stated at year-end prices. The short-cut approach illustrated in Figure 29-16 has several obvious flaws. However, it is fairly simple. Any resulting errors will be reflected by offsetting *other changes*. Application of this method to Field No. 1 results in an increase of $45,701 in pre-tax SMOG value from net changes in prices and production as shown in Figure 29-16.

Figure 29-16: Net Changes in Prices and Production Costs

(1) Compute the 12/31/99 reserves not sold in 2000:
This was done in Figure 29-15. The amount is 51,750 bbls

(2) Compute the net change in price and cost factors:
Using prices and costs in Figures 28-9 and 28-3:

Change in price ($21.33 ending – $20 beginning)	$1.33/bbl
Change in cost ($10.33 ending – $10 beginning)	.33/bbl
Net change	$1.00/bbl

(3) Compute undiscounted net change from prices and costs:
51,750 bbls x $1.00/bbl = $51,750

(4) Compute the effect on discounted present value:
$51,750 x 0.88312 (per Fig. 29-15) = $45,701 SMOG increase

Changes in Estimated Future Income Taxes

FAS 69, Paragraph 33 states that "all changes except income taxes shall be reported pre-tax." Consequently, the SMOG change attributable to changes in estimated future income taxes is simply the negative of the net change in the present value of estimated future taxes as of the beginning and end of the year. If the present value of taxes decreases by $100,000, the related SMOG change is a $100,000 increase.

Figure 29-17: Computation of the SMOG Change Attributable to the Net Change in Income Taxes

Year	Undiscounted Taxes, 12/31/99		PV Factor		P. Value Of Taxes 12/31/99	Undiscounted Taxes 12/31/99		PV Factor		P. Value of Taxes 12/31/00
2000	$ 70,200	x	.9535	=	$ 66,936					
2001	58,650		.8668		50,838	$ 51,170	x	.9535	=	$48,791
2002	39,100		.7880		30,811	34,114		.8668		29,570
2003	19,550		.7164		14,006	17,057		.7880		13,441
2004	9,775		.6512		6,365	8,528		.7164		6,109
Total	$197,275				$168,956	$110,869				$97,911

The SMOG change is $168,956 less $97,911, a $71,045 decrease.

Changes due to Timing and Other

Aside from the standardized measure changes required to be delineated in the FAS 69 disclosure, the SEC allows a catch-all category of *other* which many companies entitle *timing and other differences*, presumably referring to changes due to production profile differences and various other imprecise assumptions.

The total amount of other changes reflects the net change in present value that is not specifically identified in one of the individual computations. The *other* amount depends in part on the approach taken to calculate accretion, as illustrated in Figure 29-18.

Figure 29-18: Computation of Other Changes

	Simple Accretion (Fig. 29-11)	Precise Accretion (Fig 29-12)
Net change in standardized measure:		
Standardized measure end of year	$280,949	$ 280,949
Less standardized measure beginning of year	(413,124)	(413,124)
Net decrease for year	(132,175)	(132,175)
SMOG changes accounted for:		
Accretion of discount	58,208	48,443
Development costs incurred	102,000	102,000
Changes in estimated development costs	(2,000)	(2,000)
Net changes in prices and production costs	45,701	45,701
Changes related to income taxes	71,045	71,045
Production and sale net of production costs	(274,000)	(274,000)
Revision of previous quantity estimates	(123,858)	(123,858)
Net change accounted for	(122,904)	(132,669)
SMOG increase (decrease) due to other	$ (9,271)	$ 494

While the *other* category is a valid line item in the disclosure and utilized by many publicly held E&P companies, the amount included is arguably open to interpretation. Some companies do go through their standardized measure calculations in an organized manner with the idea that the *timing and other* category will be an insignificant number generally explained by production profile changes and leave it at that.

Other companies, specifically those with computer models and templates, can calculate the various prescribed changes in such a manner as not to include production timing changes in *other*. The argument here is that timing changes are often indistinguishable from quantity revisions, and sometimes from price revisions. So why not structure the calculation in such a way as to include the effects of timing changes with quantity variances or perhaps pricing changes? This point is valid for producing properties more so than development properties. Independent of price changes or reserve revisions, uncertainties about government regulation and financing may change the time when proved undeveloped reserves may go on production.

As was stated earlier, the *timing and other* category should be a relatively immaterial amount, but if not, the reason needs to be understood, and an additional line item disclosure may be warranted. One approach to calculating the SMOG change due to timing changes compares (1) the present value *ratio* of future cash flows projected at the beginning of the year, accreted to year end (and excluding the year's actual oil and gas sales and proved property sales) and (2) the present value *ratio* of equivalent future cash flows projected at the end of the year. If 12/31/99 SMOG reflected a present value ratio of 0.74 for discounted cash flows (accreted to 12/31/00) to undiscounted cash flows after 2000, but 12/31/00 SMOG reflects a present value ratio of 0.68 for the equivalent cash flows, the decrease in present value ratio from 0.74 to 0.68 indicates that timing of production has been delayed, causing a decrease in SMOG.[110] The decrease of 0.06 is multiplied by an undiscounted future operating cash flow to measure the SMOG change due to timing differences. This calculation typically requires modification to other calculations of SMOG changes due to quantity revisions and pricing changes in order to avoid double-counting the effects of timing changes.

An Alternative Approach to Calculating SMOG Changes

A full alternative approach to calculating SMOG changes to include a change for timing differences is not presented herein. However, Figure 29-19 does present an alternative approach that presents a SMOG change due to *reserve revisions and timing changes* and eliminates the *other* category altogether, using the preceding information for Field No. 1.

[110]The ratio decrease may also be attributable to favorable price increases that extend the economic limit of the field's life, increasing reserves to be produced in later years and decreasing the overall present value ratio. The price change affected reserve revisions and timing changes. So SMOG changes due to price changes, reserve revisions, and timing changes may not be readily distinguishable.

Figure 29-19: An Alternative Approach to Calculating SMOG changes

	Reserves (bbl)	SMOG	Taxes	Pre-tax Cash Flow	Develop. Costs	Operating Cash Flow
12/31/99						
Undiscounted value	78,750	$490,225	($197,275)	$687,500	($100,000)	$787,500
Undiscounted value/bbl		$6.23	($2.50)	$8.73	($1.27)	$10.00
Discounted value		$413,124	($168,956)	$582,080	($95,350)	$677,430
Discounted value/bbl						$8.60
12/31/00						
Undiscounted value	39,000	$318,131	($110,869)	$429,000	$0	$429,000
Undiscounted value/bbl		$8.16	($2.84)	$11.00	$0	$11.00
Discounted value		$280,949	($97,911)	$378,860	$0	$378,860
Discounted value/bbl						$9.71
Aggregate change in discounted values		($132,175)	$71,045	($203,220)	$95,350	($298,570)
		~~Net~~				
SMOG changes due to:						
Changes in income taxes (a)		$71,045	$71,045			
Accretion (b)		48,443		$48,443	($4,650)	$53,093
Development cost incurred (c)		102,000		102,000	102,000	
Changes in est. development costs (d)		(2,000)		(2,000)	(2,000)	
Current year production (e)		(274,000)		(274,000)		(274,000)
Net change in prices & costs (f)		45,970		45,970		45,970
Reserve revisions & timing changes (f)		(123,633)		(123,633)		(123,633)
Other		0		0		0
Total		($132,175)	$71,045	($203,220)	$95,350	($298,570)

(a): The net change in present value of income taxes.
(b): $48,443 computed as in Fig. 29-12. $100,000 - $95,350 = $4,650. $48,443 + $4,650 = $53,093.
(c): Actual development costs incurred of $102,000.
(d): 12/31/99 estimated development costs less 2000 actual development costs (If development costs were to occur after 1999, changes therein would also be considered.)
(e): Actual cash flow from 2000 production.
(f): Calculations of the SMOG changes due to pricing changes and quantity revisions are similar to a cost variance analysis. Calculations are shown below:

> 12/31/00 discounted operating cash flow from above (g)		$378,860	
> versus (12/31/99 reserve quantities less 2000 quantities sold) times current net price per barrel, (78,750 bbls - 27,000 bbls) x $9.71 (h)		($502,493)	$502,493
> versus adjusted prior quantities at prior net price (i):			
12/31/99 discounted operating cash flow	$677,430		
+ accretion to 12/31/00 (j)	53,093		
- cash flow from 2000 production	(274,000)		
= Adjusted prior quantities at prior net price	$456,523		456,523
Net change for reserve revision		($123,633)	
Net change for net price and cost changes			$45,970

(g): Equates to current quantity x current net price discounted to 12/31/00.
(h): Equates to adjusted prior quantity x current net price discounted to 12/31/00.
(I): Equates to adjusted prior quantity x prior net price discounted to 12/31/00.
(j): If Fig. 29-11, simple accretion, had been used, the $9,765 increase in accretion would have decreased the SMOG increase by $9,765 due to changes in prices and costs.

Summary of Changes Related to Field No. 1

The change in present value of reserves in Field No. 1 can now be shown as follows:

Figure 29-20: Summaries of Changes in Standardized Measure, Field No. 1, 1999 (Using Precise Accretion)

The following are the principal sources of changes in SMOG during 1999	Fig. 29-18 Approach	Fig 29-19 Approach
Production and sale, net of production costs	$(274,000)	$(274,000)
Revision of previous quantity estimates[111]	(123,858)	(123,633)
Development costs incurred	102,000	102,000
Changes in estimated development costs	(2,000)	(2,000)
Accretion of discount	48,443	48,443
Net change in prices and production costs	45,701	45,970
Change related to income taxes	71,045	71,045
Other	494	-
Net change	$(132,175)	$(132,175)

A cursory examination of schedules explaining major changes in the standardized measure appearing in annual reports suggests that widely differing methods are being used to compute the elements of change.

DISCOUNTED PRESENT VALUE OF DISCOVERIES AND ADDITIONS

An important element of the disclosed SMOG changes is the increase from field extensions, new discoveries, and improved recoveries. To illustrate this computation, the data for Field No. 2 for 2000 are used as a basis.

[111] The difference is due to rounding the 12/31/00 discounted price per barrel from $9.71432 (being 0.883312 x $11 in Fig. 29-5) to $9.71 (in Fig. 29-19).

Information about Field No. 2

Assume that the discovery well and a confirmation well proving up reserves were drilled in 2000. Relevant information for 2000 and as of 12/31/00 is presented in Figure 29-21.

Figure 29-21: Information About Discovery (Field No. 2) in 2000

Cost of exploratory drilling				$300,000
Cost of lease and well equipment				$138,000
Revenues				$632,000
Production Expenses				$230,000
Production		30,000	bbls	
Reserves, 12/31/00, to be produced in:				
	2001	187,500	bbls	
	2002	150,000	bbls	
	2003	127,500	bbls	
	2004	90,000	bbls	
	2005	60,000	bbls	
	2006	30,000	bbls	
	2007	15,000	bbls	
	Total	660,000		
Price per barrel, 12/31/00				$21.33
Production costs per barrel, 12/31/00				$8.00
Future development costs to be incurred				
2001: IDC				$250,000
Tangible equipment				50,000
				$300,000
2002: Tangible equipment				$31,500
Income taxes, as assumed in Figure 29-22.				

Calculation of Present Value, December 31, 2000

Based on the above data, the SMOG value of proved reserves in Field No. 2 at December 31, 2000, is computed as $4,548,804, as shown in Figure 29-22. Since SMOG change due to the new discovery must be computed based on pre-tax SMOG (i.e., discounted future net revenues), Figure 29-22 computes the present value of related income taxes and adds it to the SMOG value to calculate pre-tax SMOG.

Figure 29-22: Calculation of Standardized Measure, Income Tax Present Value and Pre-tax Standardized Measure, Field No. 2, as of 12/31/00

	2001	2002	2003	2004	2005	2006	2007	TOTAL
PRODUCTION (BBLS)	187,500	150,000	127,500	90,000	60,000	30,000	15,000	660,000
REVENUES	$3,999,375	$3,199,500	$2,719,575	$1,919,700	$1,279,800	$639,900	$319,950	$14,077,800
LESS PRODUCTION EXPENSE	(1,500,000)	(1,200,000)	(1,020,000)	(720,000)	(480,000)	(240,000)	(120,000)	(5,280,000)
LESS DEVELOPMENT COSTS	(300,000)	(31,500)	-	-	-	-	-	(331,500)
LESS INCOME TAXES (ASSUMED)	(732,000)	(673,680)	(574,770)	(405,720)	(270,480)	(135,240)	(67,620)	(2,859,510)
NET CASH FLOW	1,467,375	1,294,320	1,124,805	793,980	529,320	264,660	132,330	5,606,790
LESS DISCOUNT	(68,233)	(172,403)	(238,459)	(225,173)	(184,627)	(107,981)	(61,110)	(1,057,986)
STANDARDIZED MEASURE*	1,399,142	)1,121,917	886,346	568,807	344,693	156,679	71,220	4,548,804
ADD BACK INCOME TAX PRESENT VALUE*	697,962	583,946	452,919	290,658	176,137	80,062	36,393	2,318,077
PRE-TAX STANDARDIZED MEASURE	$2,097,104	$1,705,863	$1,339,265	$ 859,465	$ 520,830	$236,741	$107,613	$6,866,881
* USING DISCOUNT FACTORS OF	.9535	.8668	.7880	.7164	.6512	.5920	.5382	

Alternative Measures of New Discoveries

Figure 29-22's $6,866,881 pre-tax standardized measure as of December 31, 2000, may be shown in the company's Schedule of SMOG Changes as the increase from extensions, discoveries, and improved recoveries. If this is done, production from the discoveries that become proved during the year, related production expenses, and drilling and development costs incurred during the year would be omitted from the present value calculations and from the schedule of changes in standardized measure.

An alternative procedure that more closely reflects actual activities would be to (1) include the $402,000 of related operating cash flows from current production in the total of discoveries and additions, increasing the total to $7,268,881 and (2) show the sales of such production, less related production expenses, as a reduction in the standardized measure, as done in Figure 29-24.

COMBINED SMOG DISCLOSURE, FIELD NO. 1 AND FIELD NO. 2, AS OF 12/31/00

The data from Field No. 1 (Figure 29-10 and the first column of Figure 29-20) and Field No. 2 (Figure 29-22) can now be combined as shown in Figures 29-23 and 29-24.

Figure 29-23: Combined SMOG as of 12/31/00

	Field No. 1	Field No. 2	U.S.A
Future cash inflows	$831,870	$14,077,800	$14,909,670
Future production costs	(402,870)	(5,280,000)	(5,682,870)
Future development costs	-	(331,500)	(331,500)
Future income tax expense	(110,869)	(2,859,510)	(2,970,379)
Future net cash flows	318,131	5,606,790	5,924,921
10% annual discount for estimated timing of cash flows	(37,182)	(1,057,986)	(1,095,168)
Standardized measure	$280,949	$ 4,548,804	$ 4,829,753

Figure 29-24: Sources of Change in SMOG in 2000

The following are the principal sources of change in the standardized measure of discounted future net cash flows during 2000:

	Field No. 1*	Field No. 2	U.S.A.
Sales and transfers of oil and gas produced, net of production costs	$(274,000)	$ (402,000)	$ (676,000)
Net changes in prices and production costs	45,701	0	45,701
Extensions, discoveries, and improved recoveries	0	7,268,881	7,268,881
Development costs incurred during the year	102,000	0	102,000
Changes in estimated development costs	(2,000)	0	(2,000)
Revisions of previous quantity estimates	(123,858)	0	(123,858)
Purchases and sales of mineral interests	0	0	0
Accretion of discount	48,443	0	48,443
Net change in income taxes	71,045	(2,318,077)	(2,247,032)
Other	494	0	494
Aggregate change in standardized measure	$(132,175)	$4,548,804	4,416,629
Standardized measure as of 12/31/99			413,124
Standardized measure as of 12/31/00			$4,829,753

*Using the first column of Figure 29-20.

YEAR-END PRICING

In January 2000, SEC accounting staff issued the following interpretation on the meaning of year-end prices for determining the standardized measure:

> Paragraph 30(a) of FASB Statement No. 69 requires that registrants use year-end oil and gas prices in computing the standardized measure of discounted future net cash flows related to its proved oil and gas reserves. We have identified numerous circumstances in which registrants have used an average price, an average remitted price or other surrogate price for oil and gas prices rather than the year-end price. We expect registrants to comply with the requirements of SFAS 69.
>
> The staff believes that the year-end price contemplated by paragraph 30(a) of SFAS 69 is the year-end daily posted oil price or daily gas sales price ("spot price") adjusted for oilfield, or gas gathering hub and wellhead price differences (e.g., grade, transportation, gravity, sulfur and BS&W), as appropriate. Consistent use of the year-end price among registrants is critical to preserving comparability of the standardized measure of discounted future net cash flows, a measure important to investing decisions in oil and gas entities. Also, use of a consistent year-end price is critical to the ceiling test evaluation of capitalized costs for companies using the full cost method. The staff has objected to each of the following measures as a proxy for the year-end price under paragraph 30(a) of SFAS 69:
>
> - an average price for any time period,
> - the EDQ price reported on the EOTT.com website,
> - the producer's monthly contract index price, or
> - the NYMEX futures price.[112]

[112] Prepared by the accounting staff of the SEC's division of corporate finance, and posted on the web at sec.gov/offices/corpfin/acctdisc.htm-#current.

USEFULNESS OF THE DISCLOSURES

The FAS 69 supplemental disclosures are used by stock analysts in several ways. For example:

1. SMOG provides a basis to be adjusted to fair value or a comparative valuation benchmark for the publicly traded E&P company's underlying assets, primarily oil and gas producing properties.[113] The analyst then compares the benchmark value per share to the share's market value. If a company's benchmark value to market value is high compared to that of its peers, this may indicate that its stock is a better buy than the stock of its peers. Of course, other factors, such as the quality of management, exploration prospects, or unusual contingent liabilities not reflected in the benchmark value, may account for the company's high ratio of benchmark value to market value.
2. E&P costs incurred divided by reserve additions provide one method of determining finding costs per equivalent barrel. A relatively low ratio of finding costs to discovered or added reserves is an indication of profitable investment by the E&P company. The finding cost ratio may be computed in various ways, with and without costs and proved reserves attributable to proved property acquisitions. Finding cost per BOE may be based on three or five years' activity, rather than one, since some costs incurred in one year may relate to discoveries in a succeeding year.

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[113]SMOG, as a *standardized measure*, was intended to be a comparative benchmark value rather than an estimate of fair value. However, the analyst may believe that a better benchmark would incorporate expected prices and cost rates as well as a different discount rate. So the analyst might construct such a benchmark. The analyst starts by using SMOG disclosures, the reserve disclosures, and other disclosures on historical annual revenues and costs to construct a hypothetical schedule of future production and future annual cash flows from proved reserves and at year-end prices and cost rates, held constant. The hypothetical production is adjusted to a point at which the discounted after-tax cash flows match the SMOG disclosure. Then, the analyst has a reasonable *base case* of annual future cash flows from proved reserves that can be (1) adjusted for expected changes in prices and cost rates and (2) discounted by a selected discount rate to compute a benchmark value that the analyst prefers to SMOG.

3. Ratios of (1) changes in SMOG due to new discoveries, enhanced recovery, and proved property acquisitions to (2) the related costs incurred are indicative of how well the company succeeded in its acquisition, exploration, and development efforts. As a success indicator, SMOG change divided by cost expended is generally superior to the finding cost ratio that compares cost expended to reserve quantities added. Finding reserves at a cost of $1 per barrel less than that of a competitor is not cause for celebration if a company's SMOG value per barrel found is $5 less than the competitor's.
4. Disclosure of the types of capitalized costs and the costs incurred by year helps an analyst assess the unimpaired cost and approximate value of unproved property.
5. Disclosures by major geographic area provide the analyst with insights on the general risks of the E&P company's current and near-term operations.

Supplemental disclosures are not required to be audited. As a rule, the proved reserve disclosures and SMOG disclosures are never audited, i.e., incorporated as part of the audited financial statements or subjected to a separate attest examination by a CPA. However, auditing standards do require the auditor to read other information in documents containing audited financial statements to determine whether such information is materially inconsistent with information appearing in the financial statements. Accordingly, auditors typically review SMOG calculations for reasonableness during a financial statement audit. As previously stated, SMOG is, at best, only a rough surrogate for fair value. Nevertheless, analysts generally find the unaudited supplemental disclosures to be important disclosures for their analyses. Indeed, for E&P companies, one leading industry analyst found that net income and the corresponding price earnings ratio were generally meaningless and of far less value than SMOG and a calculated ratio of benchmark value to market value per share. The analyst found market value per share to be more highly correlated with the analyst's benchmark value per share (and with working capital provided by operations) than with net income or earnings.

Chapter Thirty

VALUATION OF PROVED OIL AND GAS PROPERTIES

This chapter provides an overview on estimating the fair market value of proved oil and gas properties. Such values may be needed for any of several reasons:

- Application of the FAS 121 impairment tests as described in Chapter Eighteen,
- Allocation of book values in proportion to relative fair values as required for certain property sales, as described in Chapter Twenty-One,
- Allocation of purchased price to individual assets in connection with a business combination accounted for using the purchase method,
- Management's use in assessing the acquisition or disposal of proved oil and gas properties, and
- Compliance with tax rules.[114]

The standardized measure disclosure required by FAS 69 does not reflect fair market value and, at best, is only a rough surrogate of fair market value.[115] Many rules of thumb for estimating fair market value of oil and gas producing properties can be misleading if used without regard to the more sophisticated methods generally used by buyers and sellers of such properties. Many small E&P companies use methods that are less sophisticated than those advocated in textbooks or those used by most larger oil and gas companies.

This chapter describes and compares many of the more popular valuation methods and rules of thumb to assist accountants in

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[114]Tax requirements might include, for example, (1) allocation of purchase price among multiple acquired properties, (2) determination of fair value of property contributed to charity or given as a gift to family member(s), and (3) property tax assessments.

[115]FAS 69, Paragraph 82 states that the standardized measure is not fair market value nor the present value of future cash flows but "is a rough surrogate for such measures."

understanding determinations of fair market value and fair value for financial reporting requirements.

GENERAL VALUATION CONCEPTS

Before addressing methods specific to valuing proved oil and gas properties, it is helpful to explain some basic valuation concepts applicable to valuing property and assets in general.

DEFINITIONS

In FAS 121, Paragraph 7, the FASB defines *fair value* of an asset as "the amount at which the asset could be bought or sold in a current transaction between willing parties, that is, other than in a forced or liquidation sale." In 1982, the FASB similarly defined *fair market value* in paragraph 72 of FAS 69, "Fair market value is usually defined as the exchange price that reasonably could be expected in an arm's length transaction between a willing buyer and a willing seller." The remainder of this chapter uses the term *fair value* to refer to either fair value or fair market value.

An *arm's-length transaction* refers to a purchase/sale transaction in which the buyer and seller are unrelated whereby the sales price is presumed to be at fair value unless available information indicates otherwise. There is a rebuttable presumption that the buyer and seller are both willing and competent parties to the transaction, are not under a compulsion to transact, and have a reasonable knowledge of the facts as to the value and utility of the property being sold.

A property's fair value should be stated as of its *valuation date* or *appraisal date*, i.e., the date for which the fair value applies and not the date when the estimate is made. For FAS 121 impairment tests, the valuation date is a given balance sheet date, such as the end of a quarter or year, even though the valuation process may occur around that date or several weeks after that date. In some cases, such as contesting property tax assessments, the valuation process may occur years after the valuation date.

Unless specified otherwise, the fair value is generally as of the end of the day of the valuation date. However, oil and gas property is customarily sold as of 7 a.m. on the stated sales date. So a petroleum property's fair value is as of 7 a.m. of the valuation date.

GENERAL VALUATION METHODS

For valuing a business (such as the production of oil and gas) or an income-generating asset (such as oil and gas producing property), general valuation methodology recognizes several valuation methods that some appraisers classify into three broad categories, commonly labeled:

1. the market approach,
2. the income approach, and
3. the cost approach.

In practice, categorization is difficult because each approach may encompass several specific methods or approaches, and some specific approaches may have elements of two or more of the three general approaches.

The market approach involves the use of actual sales of similar properties or stock in similar companies. If various small blocks of XYZ stock sold on a stock exchange with the closing price on the valuation date being $5 per share, that is a strong indication the fair market value of a small block of unsold XYZ shares is $5 per share on the valuation date.

Valuation methods that use other property sales as indicative of value preferably should use sales that occur on or around the valuation date, such as within 90 days of the valuation date. Other sales may be considered useful, but product prices and market characteristics can change quickly and compound the difficulty of making meaningful comparisons.

If a ten percent working interest sold in an arm's-length transaction on the first of a month for $100,000, that is a strong indication a 20 percent working interest in the same property has a $200,000 fair value on or close to the same date. However, a 20 percent interest in another producing property, even one that adjoins the first property, may have a fair value substantially different from $200,000 since its future cash flow may be substantially different from that for the first property. So the market approach has limited application in valuing oil and gas producing property.

The market approach may also calculate fair value as a multiple of historical net income, cash flow, or similar measurement of *income* for a specified time period, such as the most recent fiscal year. The multiple is often derived from analysis of (1) the known fair value of similar assets on or near the valuation date divided by (2) the historical *income* or cash flow of each comparable asset. For example, if working interests in a large field are selling for approximately four times the last 12 months' operating cash flow, that same multiple might be used to estimate fair value of a given working interest in that field. The multiple may not be indicative of value for a property in a much different field or producing formation in which the life and decline pattern of future cash flows are substantially different from those of the large field.

The income approach considers the asset's capacity for providing future income and cash flow. The income approach for oil and gas producing property typically uses a discounted cash flow analysis (DCFA). Using DCFA, the fair value is a function of the present value of expected future net cash flows, discounted using an appropriate annual discount rate. The rate may be determined by various means, including consideration of rates actually used in the market by buyers of similar properties.

The cost approach generally refers to the replacement cost method. Replacement cost rests on the theory that a knowledgeable buyer would pay no more than the cost of constructing a similar asset of like utility as of the valuation date. The replacement cost approach estimates value based on the cost of reproducing or replacing the property as if it were new, less depreciation from physical deterioration, functional obsolescence, and economic obsolescence to the extent they are present and measurable.

Under the cost approach, some appraisers may include consideration of the current property owner's historical cost of acquiring the property. If the property being valued was acquired in an arm's-length transaction by the owner shortly before the valuation date, with no interim exploration or development, then the owner's historical acquisition cost may be a strong indicator of the property's value at the valuation date. However, the historical cost of acquiring and exploring a lease generally is not indicative of the reserves found or the value of such reserves.

Replacement cost and historical cost typically are not useful in determining the value of proved oil and gas properties.

An appraiser of property will *consider* all three approaches but may be able to quickly dismiss one or two of the approaches as inapplicable or of limited use for a particular appraisal. Applicability depends on the nature of the property being valued and the nature and extent of available information on comparable sales and cost.

VALUATION METHODS FOR PROVED OIL AND GAS PROPERTIES

OIL AND GAS PROPERTY BUYERS AND SELLERS USE DISCOUNTED CASH FLOW ANALYSIS

A January 1993 report entitled *Current Investment Practices and Procedures: Results of a Survey of U.S. Oil and Gas Producers and Petroleum Consultants,* by Dr. E. L. Dougherty and Ms. Jayati Sarkar (The Dougherty Report) provides a basis for understanding petroleum industry practices for valuing oil and gas property.[116] Of the 108 companies responding to the survey in some respect, the 107 disclosing annual capital expenditures were split into four groups:

- 19 with annual capital expenditures (CapEx) above $200 million (large companies),
- 25 with CapEx between $10 million and $200 million (midsize companies),
- 15 with CapEx between $5 million and $10 million (small companies),[117] and
- 48 with CapEx under $5 million (very small companies).

The survey found that some form of DCFA was used for determining fair market value of acquisitions by 95 of 101 responding E&P companies:

- 45 companies used only DCFA,
- 50 used DCFA as well as other techniques, and
- 6 very small companies did not use DCFA at all.[118]

Using DCFA makes sense, particularly to estimate the fair value or bid price for a proved property. The value of an oil and gas property is inherently dependent on its expected future cash flow. Such cash flow varies by property and by future year and bears little relationship to the

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[116] Dr. Dougherty is the retired head of the University of Southern California's Department of Chemical Engineering. Ms. Sarkar was with the University's Department of Economics. Society of Petroleum Engineers Paper 25824 provides a synopsis of the Dougherty Report. No update of the 1993 Survey was known to exist prior to the printing of this book's 5th edition.

[117] The Dougherty Report, p. 3.

[118] The Dougherty Report, Appendix III, Table 34.

property's acreage size, historical cost, or number of wells. Expected cash flow will also vary substantially from historical cash flow due to declining production over the life of a well. Proved properties are not fungible like shares of the same class of stock of a particular company.

Since a DCFA requires historical production, engineering, land, and accounting data, it would be impractical for buying properties with limited future cash flow potential. For example, consider that a geologist wants to sell a package of ORRI interests in a dozen different wells. These interests generated only $3,000 last year. The typical ORRI owner is not entitled to all of the information, particularly cost information, that a DCFA requires. If the market approach shows that similar properties sold for a multiple of three or four times the cash flow for the past 12 months, then that market approach multiple may be the most practical way to value this package of interests.

In instances where DCFA is practical, a valuation approach that uses a general multiple of historical cash flow may be viewed as less preferable than DCFA and as a mere rule of thumb, since the relationship of expected future cash flow to historical cash flow will vary by property for a number of reasons. Some properties can be expected to produce for only a few more years, others for more than 30 years. Properties have different rates of annual production decline, and any one property's decline rate will typically vary over the life of the property. Costs associated with producing activities vary by property, change over time, and may increase even as producing rates fall. Even if costs were expected to remain relatively constant per well per month, expected net cash flow will decline much faster than production, assuming that expected price increases are not significant.

FORMS OF DCFA

DCFA generally varies in three ways:

- expressing cash flow in *nominal* or *real* dollars,
- using cash flows that do, or do not, consider incremental income taxes (*after-tax* or *before-tax*), and
- *risk-adjusting* either the cash flows or the discount rate (and discounted present value).

Figure 30-1 indicates that E&P companies, especially large and medium-sized companies, predominantly use nominal dollars in their general discounted cash flow analyses. Many small companies responding to the Dougherty survey gave conflicting information about using nominal dollars but holding prices and costs constant (i.e., using real dollars) in the cash flow schedules for valuing proved properties to be sold or acquired.

Nominal dollars refers to prices and cost rates expected or assumed to be incurred or realized at specified future times. Prices and costs are escalated over time for the effects of anticipated inflation. Nominal dollars are also called *current dollars, escalated dollars, inflated dollars*, and *dollars of the day*.

Figure 30-1: Forms of DCFA Used

Some survey results in the Dougherty Report:

- 91% (94 of 103) of companies used nominal dollars for general analysis.
- After-tax DCFA was used in general investment analysis by.
  - the vast majority (17 of 19) of large companies,
  - the majority of midsize and small companies, and
  - the minority of very small companies.
- Overall, 50.5% of the respondents used after-tax DCFA only, or used both after-tax and before-tax DCFA.
- Only 1 of 18 large companies and 11 of 24 midsize companies reported using before-tax DCFA for valuing property acquisitions.
- A slight majority of midsize companies and 74% of large companies used a combination of techniques to account for risk, including sensitivity analysis and applying probability factors. 55% of small and very small companies simply raised the discount rate.

Real dollars, sometimes called *deflated dollars* or *constant dollars*, are future prices and cost rates expressed in today's dollars or today's purchasing power without adjusting for future inflation. If oil today sells for \$25.00/bbl, but is expected to sell a year later for \$26.00/bbl when general price inflation has been three percent, the \$26.00 would be nominal dollars, and \$26.00/1.03, or \$25.24, would be real dollars for next year's production. Figure 30-1 shows that the majority of large and medium-sized companies use after-tax cash flows, whereas the majority of small companies use before-tax cash flows. After-tax DCFA is more difficult to apply than before-tax DCFA, but provides a more accurate calculation of value for a desired return on investment or return on equity. *Before-tax DCFA* uses expected cash flows that are not reduced for the buyer's net incremental income taxes attributable to the future taxable income generated by the property.

Figure 30-2 provides an example of estimating fair value using before-tax DCFA, based on nominal dollars. Prices and costs are not held constant, and the selected discount rates are 17 percent and 14.7 percent, respectively, assuming general inflation of two percent per year. Figure 30-2 is also similar to the schedules for calculating standardized measure, as described in Chapter Twenty-Nine (see Figures 29-4, 29-5, and 29-8), except that income taxes are ignored, prices and costs are escalated to reflect expectations, and the discount rate is not fixed at ten percent.

The applied before-tax annual discount rate and the related before-tax cash flows are typically greater than the corresponding after-tax discount rate and after-tax cash flows, but the relationship between the before-tax and after-tax discount rates varies by property and not merely by the effective tax rate of the buyer.

Figure 30-2: Before-Tax DCFA

Using Nominal Dollars (and assuming oil prices increase 3% /yr. and LOE increases 2.5% /yr.)

Year	Gross Oil (bbls)	Net Oil (bbls)	Price $/bbl	Sales	LOE	Net Cash Flow	Present Value @17%
2001	5,904	590.4	$ 20.00	$ 11,808	$ 7,000	$ 4,808	$ 4,445
2002	5,314	531.4	20.60	10,947	7,175	3,772	2,980
2003	4,782	478.2	21.22	10,147	7,354	2,793	1,886
2004	4,304	430.4	21.85	9,404	7,538	1,866	1,078
2005	3,874	387.4	22.51	8,721	7,727	994	490
Remainder	3,486	348.6	23.19	8,084	7,920	164	69
Total	27,664	2,766.4		$ 59,111	$ 44,714	$ 14,397	$ 10,948
	Property's estimated fair value (using nominal $s)						$ 10,948

Using Real Dollars (assuming general inflation of 2% /yr.)

Year	Gross Oil (bbls)	Net Oil (bbls)	Price $/bbl	Sales	LOE	Net Cash Flow	Present Value @13%
2001	5,904	590.4	$ 20.00	$ 11,808	$ 7,000	$ 4,808	$ 4,489
2002	5,314	531.4	$ 20.20	10,734	7,034	3,700	3,010
2003	4,782	478.2	$ 20.39	9,750	7,069	2,681	1,905
2004	4,304	430.4	$ 20.59	8,862	7,103	1,759	1,089
2005	3,874	387.4	$ 20.80	8,057	7,138	919	495
Remainder	3,486	348.6	$ 21.00	7,320	7,173	147	69
Total	27,664	2,766.4		$ 56,531	$ 42,517	$ 14,014	$ 11,057
	Property's estimated fair value (using real $s)						$ 11,057

After-tax DCFA uses cash flows reduced for the buyer's incremental income taxes from owning the property. This method is considered superior in theory to before-tax DCFA.[119] After-tax DCFA is used by substantially all large E&P companies for evaluation of mergers and acquisitions, as indicated in Figure 30-1. The forecasted pre-tax cash flows are a basis for determining future taxable income from the property to which applicable marginal federal and state income tax rates are applied to calculate incremental income taxes, as illustrated in Figure 30-3.

The calculated after-tax cash flow streams are then discounted to a present value using an after-tax discount rate (ATDR), as shown in Figure 30-3. The bid or purchase price, using after-tax DCFA, is the sum of (1) the present value of future after-tax cash flows ($337,872 in Figure 30-3) plus (2) the present value (at the same ATDR) of income tax benefits of deducting the purchase price. The second present value is a function of the purchase price, but can also be calculated by formula, as explained later in this chapter.

Figure 30-3: After-Tax DCFA Example

Year	Cash Flow Before Taxes	Add back equipment expenditures	Less the equipment's depreciation	Taxable Income	Income tax @ 40%	Cash Flow After Taxes Un-discounted	Cash Flow After Taxes Discounted @ 13% /yr.
1	$ 80,000	$ 100,000	$ (14,290)	$ 165,710	$ 66,284	$ 13,716	$ 12,903
2	160,000	-	(24,490)	135,510	54,204	105,796	88,075
3	120,000	-	(17,490)	102,510	41,004	78,996	58,198
4	110,000	-	(12,490)	97,510	39,004	70,996	46,287
5	100,000	-	(8,930)	91,070	36,428	63,572	36,679
6	80,000	-	(8,920)	71,080	28,432	51,568	26,330
7	70,000	-	(8,930)	61,070	24,428	45,572	20,592
8	60,000	-	(4,460)	55,540	22,216	37,784	15,108
9	50,000	-	-	50,000	20,000	30,000	10,616
10	40,000	-	-	40,000	16,000	24,000	7,516
11 to 15	100,000	-	-	100,000	40,000	60,000	13,022
16 to 17	30,000	-	-	30,000	12,000	18,000	2,546
	$ 1,000,000	$ 100,000	$ (100,000)	$ 1,000,000	$ 400,000	$ 600,000	$ 337,872
Present value of future after-tax cash flows							$ 337,872

This example assumes that intangibles are 100% deductible as incurred.

[119]Since 1974, editions of *Economic Evaluation and Investment Decision Methods*, a leading textbook on petroleum economic evaluations, have emphasized that economic analysis should be done after tax. The editions are authored by Franklin J. Stermole, Colorado School of Mines Professor Emeritus, and his son, John M. Stermole, Adjunct Professor at the Colorado School of Mines, and published by the Stermoles' Investment Evaluations Corporation.

Normally, the cost depletion on purchased proved producing property is greater than allowable percentage depletion. Recall that percentage depletion is also limited to the first 1,000 boe per day (equivalent to approximately $800,000 to $1,000,000 in depletion deductions per year) for all production of the taxpayer and certain related parties. Hence, percentage depletion is often ignored in the after-tax cash flow analysis.

If the purchaser had little anticipated production from other properties and if the fair value of the purchased property's equipment was substantial and the depletable leasehold cost unusually low, then percentage depletion may exceed cost depletion on the acquired property and enhance the property's value. However, a bidder with limited other production might still ignore percentage depletion on the assumption that no other bidder would use it in determining bid value.

Determination of the After-tax Discount Rate

The after-tax discount rate used in determining a bid price for acquiring proved property should be no less than the after-tax cost of the bidder's capital. Why buy a property that will return less profit than the cost of the capital to acquire the property? To do so is to earn an inadequate return to equity shareholders.

The cost of capital is usually expressed as the *weighted average cost of capital* or *WACC*. In the Dougherty Report, more than 70 percent of the large companies used WACC as the basis for determining the after-tax discount rate.[120]

A basic approach to calculating WACC is to use the after-tax cost of capital from long-term debt and the after-tax cost of equity capital. The after-tax cost of debt may be expressed as the annual interest rate on such debt (say, eight percent) multiplied by (1 less the marginal combined income tax rate of say, 40 percent), giving an after-tax cost of 4.8 percent per year. The after-tax cost of equity is the minimum net income or earnings desired by the equity shareholders for each $1 of invested equity capital. At a minimum, the cost of equity should substantially exceed the cost of debt. Over the past 50 years, equity investments have returned about six to seven percentage points more to investors than have corporate bonds (versus three percentage points more for the 15 years ended

[120]The Dougherty Report shows that 44 percent of all responding companies used subjective measures based on prior experience, and another 24 percent used WACC.

December 31, 1994).[121] So if investors in corporate bonds are earning eight percent, equity investors might expect 11 percent to 15 percent annual returns, which is after the E&P company's corporate income taxes. The after-tax cost of equity is assumed for this discussion as being 13 percent per year, a premium of five percent over the assumed eight percent cost of debt. Arguably, the assumed five percent premium should be adjusted for the riskiness of the investment. Such adjustments are applied under various discount determination methods, such as the *capital asset pricing method* (*CAPM*) and *arbitrage pricing theory*, which are beyond the scope of this chapter.

To calculate WACC, the cost of debt and equity capital should be weighted by the expected portion of capital from each source for the E&P company as a whole or for the company's proved property acquisitions as a whole. In recent years, the current long-term capital ratios for a large number of E&P companies have averaged about 25 percent to 35 percent debt and 65 percent to 75 percent equity, with wide variations by company. High debt to total long-term capital ratios of 60 percent or more are generally viewed by such companies' management as temporary and not indicative of expected mixes of capital over the long term. High debt ratios require higher returns on equity to compensate for the risk from high debt leverage. Hence, the debt and equity weights for this discussion are set at 30 percent and 70 percent, respectively.

Based on the assumed (1) 4.8 percent after-tax cost of debt, (2) 13 percent cost of equity, (3) 30 percent debt portion, and (4) 70 percent equity portion, the WACC is 10.5 percent, computed as (4.8% x 30%) + (13% x 70%). A 1997 study calculated a 9.51% WACC for E&P companies.[122] If the after-tax cost of debt were six percent and the cost of equity 15 percent, then WACC would be 12.3 percent.

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[121]For the 50 years ended December 31, 1998, large U.S. corporate stocks earned 13.6 percent, small stocks earned 14.8 percent, and corporate bonds earned 6.2 percent, compounded annually. Over the 15 years ended December 31, 1998, average annual returns for large stocks, small stocks, and corporate bonds were 17.9 percent, 11.0 percent, and 12.2 percent, respectively. These statistics are from *Stocks, Bonds, Bills and Inflation—1999 Yearbook* published by Ibbotson Associates.

[122] A 1997 study by Ibbotson Associates for the Western States Petroleum Association, as cited in “The Cost-of-Capital and Fair Market Value Discount Rates,” a paper presented by Richard J. Miller at the March 1999 Society of Petroleum Engineers Hydrocarbon Economics & Evaluation Symposium (SPE paper 52973).

The WACC does not generally change for the particular property or investment opportunity. Capital is fungible. If a company can buy a property with 80 percent to 100 percent debt collateralized by other company assets, it would be unwise to overbid by using a low ATDR equal to, or close to, the after-tax cost of debt. When the debt is to be quickly repaid over the first half of the property's productive life, the initial debt ratio is much higher than the average debt ratio over the life of the property.[123] If the company is bidding for a property to be funded 100 percent from equity, it is unwise to use a high ATDR equal to the cost of equity, since other bidders using lower, yet reasonable, ATDRs will very likely outbid the company.

Sometimes WACC is calculated on a before-tax basis using the pre-tax interest rate on debt and an equity rate calculated as the desired return on equity divided by (1 less the combined federal and state income tax rate).[124] However, generally speaking, the term *weighted average cost* of *capital* refers to an after-tax calculation. For the preceding assumptions calculating a 10.54 percent WACC, the pre-tax WACC would be (30% x 8%) + (70% x 13%)/(1-40%), or 17.57 percent. The result is the same as dividing the 10.54 percent WACC by (1 less the combined income tax rate). For a 13 percent ATDR, the same formula calculates a before-tax discount rate of 21.7 percent. However, the calculated pre-tax rate is at best a rough rule of thumb for the effective before-tax rate, which can vary by property, as illustrated later in Figure 30-9.

Company management may wish to use an ATDR above the WACC to achieve a profit above the cost of capital or to allow for unusually high risk associated with the investment but not reflected in the cash flows being discounted. A company might also inflate the ATDR to cover costs, such as incremental general and administrative costs not reflected in the cash flows being discounted. However, it is often better to build such

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[123]In one case, a property was substantially overvalued by using a low discount rate based on a WACC reflecting the initial 80 percent debt ratio. But the debt was to be rapidly paid down to an average debt ratio of less than 35 percent. Dissecting the DCFA showed that a WACC based on the 80 percent debt ratio provided an inflated fair value that was not fair value, but rather an overvaluation that would give the buying company's shareholders a rate of return *even less* than the return to its lenders.

[124]Pre-tax WACC is sometimes used in analysis for California property tax valuations where tax regulations speak of comparable before-tax discount rates, even though before-tax discount rates are not directly comparable and not generally used, except perhaps by small companies, to determine property bids.

risks and costs into the cash flow analysis rather than roughly estimate their effects through adjustment of the ATDR. One major petroleum company built incremental G&A into cash flows as a percentage increase (such as ten percent) in all operating costs and capital costs reflected in the cash flows.

Some evaluators separate future development costs and abandonment costs and calculate the present value of these future cash outflows using a lower discount factor approximating the cost of debt. This technique will lower the value of the property. The magnitude of change is a function of the difference between the ATDR and the cost of debt, and the difference between the overall cash flow and the cash outflows discounted at the lower discount rate.

In the end, the company's ATDR is based on management's judgment. The ATDR should rarely be less than WACC or substantially greater than WACC (without becoming an unrealistic dream that all the other bidders will somehow bid even less).[125]

What are E&P companies using for ATDR? That is strategic information which companies are reluctant to publicize, but various studies have attempted to discern such information.[126] Figure 30-4 shows the before-tax and after-tax discount rates shown in Tables 17 and 18 in the Dougherty Report for the respondents' general investment analyses.

[125]For examples of varying ATDR from WACC for particular investment types, see SPE Paper 28192, I*ssues in the Estimation and Application of Discount Rates for Investment Evaluation*, by J. C. Allison of Conoco, Inc. (1994).

[126] The March 1999 SPE paper 52973 "The Cost-of-Capital and Fair Market Value Discount Rates" by Richard J. Miller mentions various studies of ATDR and BTDR for E&P companies.

Figure 30-4: Discount Rates Used:
Source: The Dougherty Report, Tables 17 and 18

AFTER-TAX DISCOUNT

			# of Responses by Company Size			
	Rate	Total	Large	Midsize	Small	Very Small
	<5%	0	X*			X*
	8%	1	1			
	10%	12	1	3	3	5
	11%	4	2			2
	12%	4	3		1	
	13%	3		2		1
	14%	3		1	1	1
	15%	10	3	2	2	3
	17%	1		1		
	18%	1				1
	20%	5		2	1	2
	25%	1				1
Subtotal		45	10	11	8	16
Rate varies		5	2	2		1
Total		50	12	13	8	17
10% to 15%		**36**	**9**	**8**	**7**	**12**
As % of subtotal		**80%**	**90%**	**73%**	**88%**	**75%**

BEFORE-TAX DISCOUNT

			# of Responses by Company Size			
	Rate	Total	Large	Midsize	Small	Very Small
	8%	0	X*			
	10%	15		2	1	12
	12%	1		1		
	15%	4			1	3
	16%	1			1	
	17%	1				1
	18%	2		1		1
	20%	13		5	4	4
	22%	2		1		1
	24%	1				1
	25%	4	1			3
	30%	1		1		
Subtotal		45	1	11	7	26
Rate varies		3	1	1		1
Total		48	2	12	7	27
Subtotal's average rate		16.6%	25%	18.4%	17.3%	15.4%

*x = a single response viewed by the book's authors as non-sensical for nominal DCFA. Totals above do not reflect the x's.

Total including x's	101	16	25	15	45

Figure 30-5: Bases for the Rates in Figure 30-4
Source: The Dougherty Report, Table 19

	# of Responses, by Company Size				
	Total	Large	Midsize	Small	Very Small
Subjective Judgement (a)	40	4	12	4	20
WACC (b)	24	14	4	6	
Cost of debt (c)	8				8
Cost of debt and other bases	4		1	1	2
Cost of equity	5		2		3
Other (d)	11	1	2	2	6
Other (e)	5		1	1	3
Other, not specified	6	__	3	1	2
	103	19	25	15	44

(a) Includes 4 responses of also using methods (d) and (e) below.
(b) Includes 4 responses of also using subjective judgement and 3 more of also using other methods.
(c) In late 1992, at the time of the survey, the prime rate was 6% and the corporate bond rate approximated 8.5%.
(d) Return from a risk-free asset (govt. T-bill) plus a premium associated with the project's risk class.
(e) Expectations with respect to growth and dividend payout.

Figure 30-4 indicates that the vast majority of after-tax discount rates range from ten percent to 15 percent, but a fair number are at 20 percent. The difficulty in using these reported results is that they are for E&P investment analysis in general, including exploration activities, which are riskier than proved property acquisitions. Table 23 of the Dougherty Report shows that 45 of 103 respondents increase the discount rate as one means of accounting for increased risk.

The survey did not ask for discount rates used in acquiring property, but did ask whether pre-tax or after-tax discount rates were used. The responses, summarized in Figure 30-6, confirm that large companies generally use after-tax DCFA and WACC, whereas small and very small companies generally use before-tax DCFA. Midsize companies have no clear preference.

Figure 30-6: Discount Rate Type and Basis Used for Buying Property
Source: The Dougherty Report, Table 36

	# of Responses, by Company Size				
	Total	Large	Midsize	Small	Very Small
After-tax rate	23	7	6	2	8
After-tax rate and WACC*	4	2	1	1	
WACC	13	6	5		2
Before-tax rate**	45	0	11	6	28
Before-tax rate and WACC	2	1		1	
Both after-tax and pre-tax	2	1		2	
Actual market sales only	10	2	1	1	6
Other	3	0	0	2	1
	102	18	24	15	45

* Includes 1 large company using market sales data as well.
** Includes 2 very small companies using market sales data as well.

How do such ATDRs compare to WACC, using cost of debt at the time of the survey? At the time, late 1992, the prime rate was at six percent (compared to nine percent in April 2000) and long-term corporate bonds yielded approximately 8.5 percent per annum (compared to 7.6 percent in April 2000).[127] Assuming an 8.5 percent pre-tax cost of debt, a 30%/70% debt to equity ratio, a 13.5 percent cost of equity, and a 40 percent tax rate, the WACC would be [30% x 8.5% x 60%] + [70% x 13.5%], or 11 percent. That is on the low side of the general ten percent to 15 percent ATDR range reported in Figure 30-4.

The survey analysis assumed that all reported after-tax rates were for nominal dollar DCFA, although many small and very small companies reported never escalating prices and costs in the cash flows for valuing properties to be sold or acquired. Eleven companies (eight being small or very small) reported using real discount rates. Eight very small companies used the cost of debt as the basis for the discount rate, which is consistent with an old valuation method of discounting by the cost of debt and then reducing that present value by an additional 25 percent to 33 percent to

[127]Sources: *Federal Reserve Statistical Releases* for selected interest rates in 1992 and on May 1, 2000.

calculate fair value.[128] Such responses may partially explain why so many very small companies reported using a ten percent before-tax discount rate.

The ten percent rate is generally too low to earn a return to shareholders in excess of the return to debt holders. For example, using the rough rule of thumb in converting a pre-tax WACC to an after-tax WACC and assuming an 8.5 percent pre-tax cost of debt, a 30%/70% debt to equity ratio, and a 40 percent tax rate, the use of a ten percent pre-tax discount rate on expected cash flows equates to an inadequate 6.4 percent expected return on equity, calculated as [10% x (1 - 40%) - 30% x 8.5% x (1 - 40%)] / 70%. The equity investor should not be receiving only a 6.4 percent annual rate of return when the debt investor is receiving 8.5 percent.

An Example of After-tax DCFA

The property's fair value is in theory what the highest bidder that has a reasonable knowledge of the relevant facts will pay for it. The bid price or purchase price, using after-tax DCFA, is the sum of (1) the present value of future after-tax cash flows ($337,872 in Figure 30-3) and (2) the present value (at the same ATDR) of income tax benefits of deducting the purchase price.

The second present value is sometimes called the *depletion bonus* or *tax shield*. Assuming that the first present value was $337,872 and the tax shield was $100,000, then the bidder could pay as much as $437,872 for the property and still (after deducting the purchase price) have expected future cash flows providing the 13 percent annual internal rate of return reflected in Figure 30-3.

Deducting the $437,872 as used equipment depreciation and leasehold cost depletion reduces future taxes by, say, $175,149, or 40 percent of $437,872. The $175,149 of future tax reductions is assumed here to have a present value of $100,000.

Computing the tax shield is dependent on how much of the purchase price can be assigned to the property's equipment (E) and depreciated over eight years when the remainder of the purchase price must be deemed leasehold cost (L) and deducted over the life of the reserves as cost depletion. The amount of tax shield is dependent on the purchase price, which is dependent on the amount of tax shield, implying the need for

[128] This old method, sometimes called the Gruy Method, is discussed further near the end of this chapter.

algebra and simultaneous equations. However, the computations are not too onerous and can be expressed in the following formula: [129]

Value = [PV1 + E x (E% - L%)]/(1 - L%) where:

- PV1 is the present value of a property's future after-tax cash flows;
- E is the estimated fair value of the property's used equipment to be depreciated by the new owner; and
- E% is the percent of E that equates to the discounted present value of tax benefits from depreciating $1 of equipment. E% is a function of the allowable tax depreciation rates for used equipment, the marginal income tax rate, and the ATDR, as shown in Figure 30-7.
- L% is the percent that equates to the discounted present value of tax benefits from depleting $1 of leasehold cost. L% is a function of the percent of reserves to be produced each year, the marginal income tax rate, and the ATDR as shown in Figure 30-8.

Figure 30-7: Computing E% for the Tax Shield

Year	[A] Well Equipment Depreciation Rates	[B] Federal & State Combined Tax Rate	[C] Discount Factor for 13% ATDR	[D] E% [A] x [B] x [C]
1	14.29%	40.0%	0.9407	5.38%
2	24.49%	40.0%	0.8325	8.16%
3	17.49%	40.0%	0.7367	5.15%
4	12.49%	40.0%	0.6520	3.26%
5	8.93%	40.0%	0.5770	2.06%
6	8.92%	40.0%	0.5106	1.82%
7	8.93%	40.0%	0.4518	1.61%
8	4.46%	40.0%	0.3999	0.71%
	100.00%			28.15%

[129] Formula derivation and further explanation of the tax shield concept can be found in SPE Paper 19858, *Understanding Minimum Sales Price and Maximum Purchase Price* by G. C. Daley and D. R. Elmer of ARCO (1989).

Figure 30-8: Computing L% for the Tax Shield

Year	Future Production of Net Reserves (BOE)	[A] % of Reserves Produced	[B] Federal & State Combined Tax Rate	[C] Discount Factor for 13% ATDR	[D] L% [A] x [B] x [C]
1	20,000	9.75%	40.0%	0.9407	3.67%
2	30,000	14.62%	40.0%	0.8325	4.87%
3	25,500	12.43%	40.0%	0.7367	3.66%
4	21,675	10.57%	40.0%	0.6520	2.76%
5	18,424	8.98%	40.0%	0.5770	2.07%
6	15,660	7.63%	40.0%	0.5106	1.56%
7	13,311	6.49%	40.0%	0.4518	1.17%
8	11,314	5.52%	40.0%	0.3999	0.88%
9	9,617	4.69%	40.0%	0.3539	0.66%
10	8,175	3.98%	40.0%	0.3132	0.50%
11	6,949	3.39%	40.0%	0.2771	0.38%
12	5,906	2.88%	40.0%	0.2452	0.28%
13	5,020	2.45%	40.0%	0.2170	0.21%
14	4,267	2.08%	40.0%	0.1921	0.16%
15	3,627	1.77%	40.0%	0.1700	0.12%
16	3,083	1.50%	40.0%	0.1504	0.09%
17	2,621	1.28%	40.0%	0.1331	0.07%
	205,150	100.00%			23.11%

Fair value of the property's existing equipment is not based on DCFA but generally on replacement cost or on recent historical cost reduced, i.e., depreciated, for prior use. The equipment value has little impact on the tax shield when E% approximates L%, as seen in Figure 30-9.

The equipment's fair value (E) is a portion of the property's fair value, not an addition to the property's fair value. In appraising the *property*, the term *property* refers to the existing equipment and the lease rights combined. The equipment and lease rights are both necessary to generate the expected future cash flows that determine value. Once the property is acquired, the portion of acquisition cost equal to the acquired equipment's fair value is allocated to equipment cost. The remaining acquisition cost is allocated to lease acquisition cost. Lease acquisition costs are often called property acquisition costs for GAAP and income tax purposes but in a narrower sense of the word than the appraisal concept of property.

Using the examples in Figures 30-3, 30-4, and 30-5 and assuming that the fair value of the property's equipment is $120,000, then the after-tax valuation formula is [$337,872 + $120,000 x (28.15% - 23.11%)] / (1 - 23.11%), or $447,288. The tax shield of $109,416 (i.e., $447,288 - $337,872) is 24.46 percent of the $447,288 calculated value. The 24.46 percent is consistent with $120,000, providing a 28.15 percent tax shield. The remaining $327,288 provides a 23.11 percent tax shield for weighted average tax shield of 24.46 percent.

Why After-Tax DCFA is more accurate than Before-Tax DCFA

Consider that the tax shield will vary as a percent of the maximum purchase price depending on (1) how much value can be assigned to equipment, (2) the productive life of the property, (3) the state in which the property is located (which affects the marginal income tax rate), (4) the marginal income tax rate, and (5) the ATDR. Consider that the present value of future after-tax cash flow will depend on how much of the cash expenditures are not immediately deductible (e.g., equipment on future development wells) and when those expenditures occur. Since a property's fair value will vary as the tax shield varies, the before-tax discount rate which must be applied to the pre-tax cash flow stream to calculate a bid price comparable to the fair value will vary by property, as illustrated in Figure 30-9.

Assume that an E&P company wants to calculate a bid price for a property using before-tax DCFA to achieve a 15 percent return on equity. What before-tax discount rate should be used? One doesn't know without doing an after-tax DCFA first, so why try to use before-tax discounting instead? Can the company use one standard before-tax discount rate for evaluating all of its acquisitions? No, as demonstrated in the wide range of rates for the five related cases in Figure 30-9. For such reasons, the majority of medium and large E&P companies use after-tax DCFA rather than before-tax DCFA.

Figure 30-9: Appropriate Before-Tax Discount Rates Vary

To achieve a 13% return after income taxes, the appropriate before-tax discount rate can vary from approximately 18% to 28% as illustrated below even if the combined federal and state income tax rate is the same. In each case the future before-tax cash flows are $1 million.

	Years of Production	Tax Rate	Before tax discount rate Low*	High*	L%
Case A, Figures 30-2 to 30-4	17	40%	21.4%	22.9%	21.5%
Case B (Case A, higher development $)	17	40%	18.6%	19.9%	21.6%
Case C (Case B, shorter life)	10	40%	21.4%	22.3%	24.0%
Case D (Case B, longer life)	27	40%	23.5%	27.6%	11.2%
Case E, an offshore gas field	5	40%	21.9%	21.9%	30.9%
Case A, 44% tax rate	17	44%	22.8%	24.7%	23.6%

*Rate varies depending on assumptions as to the value of existing equipment. There is no rate variation for short-life properties, such as Case E, for which equipment depreciation is based on the same unit-of-production method as lease cost depletion.

What about the E&P company that expects to pay little or no income taxes due to factors such as the following:

- The company expects to reinvest cash flow in substantial intangible drilling costs that are immediately deductible;
- The company is small and has as much as $1 million per year in percentage depletion deductions;
- The company has substantial net operating loss carryforwards, or
- The company is a partnership (as were seven respondents to the aforementioned Dougherty survey) and therefore not subject to corporate income taxes.

Such a company might cautiously use before-tax DCFA. The tax benefits of deducting intangible costs are a factor in the economic analysis of the decision to drill. Company management should be careful not to double-count the tax benefits—once to justify drilling and again to justify ignoring the incremental tax increase from acquiring proved property. The percentage depletion benefit not needed to shelter income from existing properties is usually minimal, greatly limiting the size of proved property that can be reasonably acquired using before-tax DCFA. The existence of companies with unused net operating loss carryforwards, and partnership status has not prevented many other companies that use after-tax DCFA from buying proved properties.

ADJUSTING FOR RISK

Chapter Sixteen contains several references to the uncertainties related to estimating proved oil and gas reserves. Estimating expected future cash flow entails additional risks relating to expected pricing, costs, new discoveries, technology changes, and production timing.

Expected future cash flow need not be a single best estimate. It may be a risk-weighted aggregation of future cash flows. For instance, planned future development costs might be given full weight if they are to occur no matter the level of subsequent production. The estimated future production of proved producing reserves might be reduced by only ten percent to reflect the *reasonable certainty* of proved producing reserves. Proved undeveloped reserves might be reduced by a larger percentage, and estimated production of probable reserves, might be reduced by, say, 40 percent or 50 percent to recognize the greater uncertainty of such production.

The Dougherty Report found that some buyers and sellers account for risk by increasing the discount rate or otherwise reducing the present value without adjusting the underlying cash flows. However, the appropriate discount rate increase or the appropriate present value reduction (sometimes called a *haircut*) is difficult to determine. Risk-weighting the cash flow streams is a more direct way to quantify perceived risks.

In the Dougherty Report, a majority (60.2 percent) used probabilities in determining a sales or bid price; 80.6 percent of these include probability estimates for proved nonproducing reserves. Twenty-eight (27.2 percent) of 103 respondents used only producing reserves in the DCFA, and 25 of those 28 were small companies.

For many years, some oil and gas companies and petroleum engineering consultants used a form of DCFA that discounted the cash flows at a *safe* rate of interest equivalent to the pre-tax borrowing rate, and then adjusted for risk and equity profit by reducing that present value by 25 percent to 33 percent to calculate a bid price or fair value for the property.[130] This approach has the same weaknesses as the before-tax DCFA approach addressed in Figure 30-6 to achieve a desired annual rate of return on equity capital.

[130]The method is more fully addressed in the *Petroleum Engineering Handbook* published by the Society of Petroleum Engineers.

THE SPEE ANNUAL SURVEY OF ECONOMIC PARAMETERS

The Society of Petroleum Evaluation Engineers (SPEE) conducts an annual survey of economic parameters used in property evaluations and provides a report to participants, SPEE members, and other interested parties. The annual report serves as a limited indicator of price escalations, cost escalations, discount rates, and risk adjustments employed by E&P companies and their consultants in determining the fair value or bid price for proved oil and gas property in general.

Below are highlights from the latest report entitled *The Eighteenth Annual Society of Petroleum Evaluation Engineers Survey of Economic Parameters Used in Property Evaluation, June 1999*, summarizing the findings of the April 1999 SPEE Survey:

- Respondents were identified as 54 percent Producers, 37.1 percent Consultants, 9.1 percent Bankers, and 3.5 percent Other.
- The average projected WTI posted oil prices were $14.99/bbl. in 1999 escalating only 29 percent in eight years to $19.39/bbl. in 2007 (whereas actual prices doubled by early 2000).
- The average projected gas cash prices at Henry Hub in Louisiana were $2.03/mmBtu in 1999 also escalating only 29% in eight years, to $2.61/mmBtu in 2007.
- Costs were generally escalated at the projected inflation rate, averaging approximately 2.5% per year.
- DCFA was used by 89.1 percent of respondents for determining value of property.
- The SPEE Survey reported an average discount factor of 13.95 percent which is of limited informational value since the survey failed to disclose the average rates for the following categories of responses:

    - Discount applied to cash flows using escalated (nominal) prices and costs (61 percent),
    - Discount applied to cash flows using constant prices and costs (39 percent),
    - Discount applied to cash flows adjusted for risks (51 percent),
    - Discount applied to cash flows not adjusted for risks (49 percent),

- Discount applied to cash flows before income taxes (85 percent), and
- Discount applied to cash flows after income taxes (15 percent).

For oil and gas property acquisitions, reserve quantities or resulting cash flows would be multiplied by factors to adjust for risk. The SPEE Survey's averages of such factors were as follows:

- 97 percent for proved producing,
- 85 percent for proved shut-in,
- 75 percent for proved behind-pipe,
- 56 percent for proved undeveloped,
- 32 percent for probable behind-pipe,
- 28 percent for probable undeveloped,
- 8 percent for possible behind-pipe, and
- 6 percent for possible undeveloped.

SENSITIVITY ANALYSIS

Sensitivity analysis typically generates several discounted cash flow analyses under varying assumptions of price, cost, production, and acquisition cost. The multiple cash flow analyses aid in evaluating how the profit and rate of return for a prospective acquisition would change if actual parameters vary from base assumptions.

Sensitivity analysis primarily serves to evaluate risks, but can also aid in determining a bid price. Rather than rely on a formula to calculate a bid price, the cash flow analyses include an assumed acquisition price to calculate the effective after-tax internal rate of return under the various cases. The cash flow analyses might even include assumptions as to debt financing so that annual rate of return on equity can be calculated. The proposed bid price or acquisition price can then be varied in the cash flow analyses to reflect the desired internal rate of return, or (if borrowings and debt repayments are reflected in cash flows) to reflect the desired rate of return on equity.

OIL AND GAS PROPERTY APPRAISERS ALSO USE DCFA

For many of the same reasons that buyers and sellers in the marketplace prefer to use DCFA, appraisers also seem to prefer DCFA. As indicated earlier in the chapter, the market approach has limited application, since the value of one property is not directly indicative of the value of a property in another field or producing from a different reservoir. *Comparable* sales in the marketplace usually refer to transactions with known selling prices, sales dates, and the underlying DCFA information that may indicate suitable parameters, such as discount rate or price forecasts, in developing the discounted cash flow calculations for the property being appraised. In that sense, comparable sales are not being used in a market approach but do provide parameters in the DCFA method under the income approach. Comparable sales may also provide information in applying rules of thumb discussed later in this chapter.

The historical cost method and the replacement cost method also have limited application for valuation of proved oil and gas property. The historical cost of exploring for and developing oil and gas reserves has little relation to the value of the discovered reserves. The historical cost of recently acquired proved producing property may be relevant and useful, since such cost should reflect the value of the already discovered reserves.

Calculating the cost of replacing a property or reserve base that would generate equivalent future cash flow is just a roundabout way of applying DCFA to the property to be valued. The cost of replacing the same volume of reserves is meaningless, since the value of a given quantity of reserves depends on other factors, such as the production costs, how quickly the reserves are produced, and the expected selling price of each produced barrel or mcf.[131]

When applying DCFA, the appraiser may use petroleum engineering analysis of the property's recent historical production, costs, and sales prices to estimate future gross and net production, any future development costs, future operating costs, and initial sales prices. The appraiser also needs to choose between before-tax and after-tax DCFA, choose a corresponding discount rate, and choose price escalation rates.

The choice of before-tax versus after-tax DCFA may depend on the practices of likely buyers and sellers of such properties. The Dougherty

[131]In a celebrated complex court case several years ago, the jury apparently missed this point, whereupon the jury's presumed value of certain proved oil and gas properties was billions of dollars above any reasonable estimate of fair value of the properties.

Report suggests that properties with a value in excess of the $10 million cape of small companies are likely to be purchased by medium and large buyers who generally use after-tax DCFA. So an initial approximation of the property's fair value may suggest which method should be used.

To select the discount rate, the appraiser may consider a combination of approaches, depending on the data available:

- Using, if available, comparable market information, i.e., the buyer's cash flow analysis and purchase price of any comparable property sales acquisition, to calculate the effective discount rates reflected in such comparable transactions,
- Using surveys of discount rates used in the marketplace, and
- Calculating a reasonable, but theoretical, discount rate based on WACC or other means found to be employed by buyers and sellers of similar property.

Although cash flow analysis of comparable properties is difficult to obtain, when available it provides a basis that is more objective, and thus more supportable, than the appraiser using judgment to calculate a discount rate from WACC or some other theoretical formula. The appraiser needs to be careful that each comparable transaction is truly arm's length and does not reflect an overvaluation arising from error(s) in the winning bidder's knowledge of the relevant facts.

The appraiser also needs to be careful not to directly use the before-tax discount rates of comparable property sales to apply a before-tax discount rate to the property being appraised unless such properties can be shown to typically be valued in the marketplace using before-tax DCFA. When a property is likely to be sold at a value determined by after-tax DCFA, the comparable property sales' after-tax discount rates need to be determined to provide a basis for an after-tax discount rate for the property being appraised, as suggested by the wide variation in before-tax discount rates found in Figure 30-9, to achieve the same after-tax discount rate. A comparable property sale's after-tax discount rate is the rate that when applied to after-tax cash flows (using the aforementioned after-tax valuation formula) yields the cash-equivalent sales price of the comparable property.

For FAS 121, fair value may be determined internally by company personnel. Objective, comparable sales information may not be readily available, but the company's methods employed to determine acquisition prices of similar properties may be a reasonable basis for determining discount rates and fair values of properties being retained.

The price and cost escalation rates may be based on (1) the escalation rates found in the buyer's cash flows used as a basis for determining the discount rate and (2) national or regional surveys of escalation rates employed by buyers and sellers in determining transaction prices of proved property sales. The first basis is often unavailable to appraisers.[132] A variety of published national surveys of prices and cost escalation rates are available, e.g., the *Oil & Gas Journal*'s spring and fall price forecast compendiums, the aforementioned annual surveys by the Society of Petroleum Evaluation Engineers, and quarterly published surveys of selected E&P companies and energy lending banks available from various sources such as Randall & Dewey, Inc., and Madison Energy Advisors, Inc., both of Houston, Texas.

In the past few years, a third basis has developed—the equivalent future prices that may be locked in for several months by purchase of oil and gas futures contracts or for several years by the purchase of over-the-counter swaps and derivative instruments.

RULES OF THUMB

Several techniques are used to determine approximate fair value or to serve as a *check* on the reasonableness of the value determined by DCFA. Such *rules of thumb* have limited application in determining fair value absent DCFA.

Payout

Payout occurs when cumulative expected future net cash flow will equal the purchase price and recoup the investment. A potential buyer might project future cash flow and set the fair value equal to the cumulative expected future cash flow after a given number of months of production, generally ranging from 36 to 60 months. This simplistic

[132] A notable exception occurs in California. Buyers of California oil and gas property are required by law to provide the county assessor with the cash flow analysis that was the basis for the acquisition. The assessor's database is confidential absent a court order to disclose it. However, Richard J. Miller & Associates, Inc. has obtained similar information from more than 200 California property acquisitions since 1982 to provide a database for annual analysis of discount rates on behalf of the Western States Petroleum Association.

approach ignores the extent and timing of cash flows after payout is reached. Intuitively, a property with, say, $60,000 of additional cash flow should be worth less than a property with $400,000 of additional cash flow after payout.

A variation is *discounted payout* whereby fair value is the discounted present value of future cash flow for a chosen number of months, ignoring subsequent future cash flow. The discount rate might be the bank borrowing rate to reflect when a loan for the full purchase price amount could be paid off by the estimated future cash flow.

Payout or discounted payout is not so much a tool in determining fair value as it is a useful supplement to DCFA by providing a sense of how soon the purchase price can be recouped from expected future cash flows and not be affected by long-term changes from expectations.

A Multiple of Current Cash Flow

Similar to payout, a multiple of current cash flow estimates fair value by multiplying a chosen number of months by the current monthly cash flow from the property. The number of months might range from 24 to 60, depending on the size and quality of the property being valued. For instance, properties with very small cash flow, such as $1,000 per year, may have too much administrative burden relative to the cash flow to justify a high multiple. The current monthly cash flow might be an average for the past year or reflect the current month's production at a historical or projected annual average price and LOE cost per month per well.

Value per BOE of Proved Reserves

Many buyers of proved properties publicly disclose the acquisition cost, the estimated proved oil and gas reserves acquired, and the date or approximate date of the acquisition. This provides a large, publicly available database of the acquisition cost per equivalent barrel of proved reserves for proved property acquisitions.[133] In theory, the acquisition cost per boe of properties *closely similar* to the property being appraised and selling at around the valuation date is a reasonable indicator of value for the subject property. It usually provides a more objective, outside basis

[133]Barrel of oil equivalent may be computed on the basis of relative energy content or on the basis of relative benchmark prices of oil and gas.

than DCFA, but an average boe is not necessarily indicative of value for a particular property.

Acquisition cost per boe can vary widely among dissimilar properties. For example, if the average U.S. acquisition cost per boe were $5 per barrel in 2000, the mid-2000 value of low-priced heavy oil reserves to be produced in the U.S. over 30 years at high operating costs may be less than $2 per boe because the future cash flow per barrel of such reserves is well below the U.S. average and the cash flow occurs much later than for U.S. properties in general. Proved undeveloped reserves are generally worth less per reserve boe than proved developed reserves. Gas producing properties may vary in value due to the location of the properties, even within the U.S. or a region of the U.S. Several years ago, a leading petroleum stock market analyst overvalued a company's shares by 50 percent simply by assuming that the company's low-quality properties were worth the average U.S. acquisition cost per boe.

Valuing a property based on comparable properties' acquisition cost per boe is easy to do, but hard (if not impossible) to do right.

Value per Producing BOE per Day

Similar to the value per boe of proved reserves, the value per producing boe per day estimates fair value by multiplying the current rate of production by an empirical factor derived from prior experience or analysis of similar properties. If similar properties sold for the equivalent of $10,000 per boe per day of production at the time of sale, and if the subject property produces 200 barrels per day, then the subject property's value is estimated to be $10,000 times 200 boe, or $2,000,000.

Obviously, this method does not account for nonproducing reserves, i.e., proved behind-pipe, proved undeveloped, and probable or possible reserves. Use of the method is limited largely to fully developed properties with closely comparable property transactions.

Net Cash Flow to Value Ratio

An old rule of thumb is that a property's undiscounted expected future cash flow should be no less than 2.5 to 3 times the acquisition cost or value. This allows for some profit over several years. However, the method provides only a rough indicator of value that tends to undervalue properties with short production lives or rapid decline rates and overvalue properties with long production lives, low decline rates, or substantial near-term future development costs.

Calculating net cash flow to value highlights that DCFA valuation of proved properties with very short lives could reflect a seemingly reasonable discount rate but provide little profit in relation to the investment. If a company's WACC is 11 percent, and property A will return 14 percent over four years whereas property B will return 13 percent over 20 years, property B may be the better investment if property A's cash flow is expected to be reinvested at only 11 percent. Arguably, a company may want to increase the discount rate and decrease the value of short-lived properties. One economic analysis technique not generally employed by E&P companies is to compare short-lived and long-lived properties by assuming that the cash flow is reinvested at a given rate, such as the company's WACC.

Chapter Thirty-One

OFFSHORE OPERATIONS AND ENHANCED RECOVERY

In prior chapters reference has been made to offshore oil and gas activities and to enhanced recovery projects. Although the ultimate objective of these activities, the production of oil and gas, is the same as that of onshore efforts, the physical activities involved are far different from the typical routine onshore projects. As a result, there are unique accounting problems for both types of operations. In this chapter we will describe the diverse aspects of both types of activities and analyze the special accounting problems they create.

OFFSHORE OPERATIONS

Within the jurisdiction of United States territorial waters, oil and gas operators may acquire mineral leases from state governments or from the federal government. On the Atlantic and Pacific coasts, state governments own mineral rights to a distance of three miles from shore; state ownership extends nine miles into the Gulf of Mexico. The federal government controls rights beyond the three-mile and nine-mile points. Leases are obtained from both state governments and the federal government through competitive bidding. Typically, announcements of offshore tracts available for bid call for a fixed specified royalty, with companies making competitive bonus bids for the tracts involved. In some cases, however, state and federal governments have asked for competitive royalty bids with a fixed bonus and, less frequently, have required net-profit-sharing leases.

LEASING

Jurisdiction and ownership of mineral rights in most of the outer continental shelf areas of the world have been agreed upon under the terms of the Geneva Convention of the High Seas of 1958.

The procedures for leasing outer continental shelf (OCS) areas from the federal government were set up in the OCS Lands Act of 1953-1954, and

OCS leasing is administered by the Minerals Management Service (MMS) of the U.S. Department of the Interior.

The offshore leasing guidelines established by the MMS seek to balance the needs of the federal government for environmental protection, resource development, and a fair return, while at the same time establishing a reasonable and practical system for leasing. Offshore blocks are generally 5,760 acres (nine square miles), have a royalty rate of 16.67 percent (one-sixth), a primary term of five years, and an annual rent that is due unless drilling or production operations are underway. Recognizing the additional risk associated with deep-water operations, deep-water blocks (generally water depths greater than 400 meters) may have eight- or ten-year terms, and a royalty rate of 12.5 percent (one-eighth). The leasing procedure may be summarized as follows:

(1) To allow companies time to conduct seismic surveys or other prospecting prior to the lease sale, the MMS publishes lists of offshore tracts to be leased several years in advance.

(2) The MMS gives 30 days advance notice in the *Federal Register* that a lease sale will be held in a particular area. Within that area, companies can submit bids on any unleased block, unless it has specifically been excluded from the sale by the MMS for some specific reason. An environmental impact statement will have been prepared prior to the sale, and a hearing held.

(3) On the bid date, the MMS opens sealed bids on a block-by-block basis, revealing the name (or names, since companies often make joint bids) of each bidder and the amount of the bid.

(4) After opening the bids, the MMS determines a confidential minimum acceptable bid level for the unleased block.

(5) Two months after opening the bids, the MMS awards the lease to the highest bidder if the bid exceeds the minimum acceptable amount.

The same types of exploration methods are used in offshore operations as in onshore work. Magnetic, gravimetric, and seismic equipment are commonly employed. Because many of the first offshore oil and gas prospects in the Gulf of Mexico were found around salt domes, gravitational exploration methods were especially important. Marine seismic exploration uses an *air gun* which discharges air under high pressure. The resulting high-pressure bubble oscillates, and seismic waves are generated and reflected. The reflected sound waves are recorded at the water's surface by *hydrophones*, a marine adaptation of geophones.

Seismic surveys are generally cheaper per acre offshore than on land. 3D seismic is rapidly becoming the most common type of offshore survey.

DRILLING

Early offshore drilling was merely an extension of onshore activities. Some of the first offshore drilling was done from piers stretching out hundreds of feet from the beach at Santa Barbara, California. In the marshes of Louisiana in the 1920s and 1930s, drilling platforms were constructed by dredging channels, moving in barges, and sinking them in water four to eight feet deep. The barges were fastened into place by wooden pilings. In the bays along the coast of the Gulf of Mexico, wooden platforms were constructed on the tops of wooden pilings. If the wells were successful, production equipment would be installed and the oil transported by flowlines to an onshore tank battery.

In deeper water, however, the methods described above are inappropriate, especially if weather conditions are severe. Massive platforms rising hundreds of feet from the ocean floor to the water's surface may be necessary, and special production facilities must be installed. Thus, a single producing well would rarely produce enough oil or gas to justify the cost of the facilities. It therefore becomes necessary to carry out a carefully planned program of exploratory drilling, evaluation or appraisal drilling, and development drilling. Exploratory and evaluation drilling is conducted from mobile rigs, and the wells are usually abandoned, even if oil or gas is discovered. Development wells, on the other hand, are drilled from massive platforms that may have room for drilling numerous wells—generally 8 to 30 drill slots, but possibly as many as 60 slots for deep-water platforms when a second platform for a large field is cost-prohibitive. Production facilities are constructed on the platform to handle output from all the wells.

Several types of mobile exploratory drilling rigs are used, the most common types being:

- Submersible rigs,
- Jackup rigs,
- Semisubmersible rigs, and
- Drilling barges and drilling ships.

The physical conditions of the environment, such as water depth, weather conditions, and distance from port or shore, largely determine which type of exploratory rig will be used. Related factors, such as positioning capabilities of the rig, support requirements (including living accommodations), and mobilization problems of getting the rig on location, are also important.

Submersible rigs are similar to sunken barges and were among the earliest offshore exploratory rigs. A submersible rig has a lower hull and an upper hull. The lower hull provides buoyancy when floating the unit from one location to another, and the upper hull provides working space and the crew's quarters. When the rig has been moved to location, the lower hull is flooded and the rig sinks until it rests on the seabed. When the drilling operation is finished, the ballast water is forced out of the lower hull and the unit is re-floated and moved to a new location. A major disadvantage is that it is difficult to move a submersible rig. Most submersible rigs operate in shallow water (less than 50 feet), although some may operate in water up to 100 feet deep. Few submersible rigs are being constructed today.

Jackup rigs, which are relatively inexpensive, may be used in considerably deeper water than submersible rigs. The depth limit is generally 350 feet, but Gorilla class jackups can work in water up to 550 feet in the Gulf of Mexico and 400 feet in the North Sea. The rig has a watertight hull, and while the rig is in transit the legs are jacked up above the hull. When the rig has been moved to the drill site, the legs are jacked down to the seabed. Then the hull is jacked up above the water's surface so that tides and waves will not interfere with operations. The jackup rig is quite stable. Jackup rigs are difficult to tow, however, and the legs must be shortened or removed for long trips. There have been several accidents in jacking platforms up or down.

In deeper waters submersible rigs and jackup rigs cannot be used. *Semisubmersible rigs* (or semis, pronounced sem'-ize) operate in depths generally up to 2,000 feet, but PetroBras has a well drilled from a semi in 8,022 feet of water at Marlim field. A semi's hull is floated and submerged just below the water's surface. The semisubmersible rig has a working deck similar to the jackup rigs, but it is stabilized by ballasting its pontoons and columns to a predetermined depth. The working area on top of the columns, which in turn are on top of the pontoons, rides above the water's surface. Semis are generally kept over the drill site by anchoring. Newer rigs, however, are self-propelled and may be kept in place above the drill site, without anchoring, through the use of *Dynamic Positioning* (DP), i.e., electrically powered propeller *thrusters* that direct their thrust in the desired direction. The semisubmersible rig is especially useful in deep, rough water such as the North Sea. A major disadvantage of semisubmersibles is that they have limited cargo and storage capacity and must depend heavily on supply ships and tugboats.

Drilling ships (drill ships) are seagoing vessels that serve as exploratory drilling platforms. Drill ships are much like traditional ocean-going vessels and are self-propelled. Because drill ships require a *sailing crew*, they have high operational costs. They offer the advantages of fast movement between sites and store large quantities of material (thus requiring fewer support ships). Drill ships have ballasting systems as well as *thruster* systems to provide stability and keep the ship over the drill site. Drill ships can work in greater depths than semis.

Drilling barges are not self-propelled and must be moved by tugboats, thus increasing travel time. Like submersibles, the barges are moved to the drilling location and ballasted so that they rest on the bottom. They typically work in water depths of less than ten feet and are best suited for protected areas such as marshlands, like those in South Louisiana or many parts of Nigeria.

DRILLING OPERATIONS

Drilling operations of an offshore rig are almost identical to those of onshore rigs, although additional technical refinements are necessary for work on *floaters* (semis and drill ships). Despite anchoring or dynamic positioning, there is still a large amount of movement, particularly up and down movement from waves, or *heave*. Special *motion compensators* must be used to isolate the drill string from the heave. Marine riser systems are used to guide the drill stem from the drilling vessel to the subsea wellhead and to conduct the drilling fluid between the well and the vessel. Special emergency disconnect equipment must be used so that in the event the vessel is forced off location (by approaching hurricanes, loss of power, broken anchor chains, collision with another ship, etc.), the well can be re-entered safely.

A special problem in offshore drilling is the installation of blowout preventers. If nonfloating rigs are used, the blowout preventer for an offshore rig is almost identical to those onshore and will be installed beneath the rig floor. If floating rigs are used, the blowout preventer must be installed at the wellhead on the sea floor to maintain control of the well in the event of an emergency disconnect. Subsea blowout preventers are similar to regular blowout preventers but are equipped for remote control operation via electrical or hydraulic power.

EVALUATION AND DEVELOPMENT WELLS

As previously pointed out, in order to produce oil and gas from deep-water offshore reservoirs, especially in areas where violent weather occurs, it is necessary to build massive permanent platforms. The platforms and related development wells may cost hundreds of millions of dollars. Thus, it may be necessary for a field to contain proved reserves of 200 million equivalent barrels of oil or more before the high cost of development can be economically justified. A single well will not *prove up* this quantity of reserves. It will be necessary to drill several *evaluation* wells to help assess the probability that adequate reserves exist to justify development and to determine the precise location for constructing a permanent platform to be used for drilling development wells and installing production facilities. Evaluation wells use the same type of drilling equipment as exploratory wells and, like the latter—especially if drilled in deep water—are rarely expected to be completed as producers even though they verify the existence of proved reserves. Evaluation wells that cannot be used for future development are termed *expendable* wells, although evaluation wells can sometimes be *temporarily abandoned* and later tied into the production platform.

Once evaluation wells confirm the existence of reserves adequate to justify the construction of a permanent platform and the drilling of development wells, platform construction begins. These fixed platforms, made of concrete or steel, must withstand severe environmental conditions such as hurricanes, icy seas, earthquakes, and strong winds. Many factors determine the type of platform to be used and its structural details. The platform is typically fabricated onshore, then floated or transported on barges to the permanent location, where it is erected. To facilitate the drilling of multiple wells, the platform has *drilling slots* arranged in rows, forming a rectangle. The drilling derrick is movable and is skidded from one drilling slot to another as drilling of a well is completed. The wells are directional wells (see Figure 8-6) that extend away from the platform.

PRODUCTION AND TRANSPORTATION

Production techniques in offshore activities are similar to those onshore. Gas, oil, and water must be separated, using separators almost identical to those onshore. In many jurisdictions it is necessary to either treat the water to remove impurities before it can be discharged into the sea or to reinject the water into the reservoir. In either event, additional equipment must be installed on the platform or in tender ships to properly handle the water. Gas is gathered and transported to shore by pipelines, whereas oil may be either accumulated in storage tanks for subsequent transport by tanker or transferred directly from separators and treaters into the tanker. If an oil pipeline has been constructed, the oil may be run from treating equipment directly into the pipeline.

Offshore pipelines are laid by pipe-laying barges. The pipeline is continuously welded together and laid along the floor bed. On softer and shallower bottoms, the pipeline is buried. Some pipe-laying barges are semisubmersible to minimize the effects of wind and waves in rough water. In recent years, flexible pipeline laid by *reel barges* has been developed.

REMOVAL AND RESTORATION

As discussed in Chapter Seventeen, a major cost of offshore operations is incurred after oil and gas production has ceased. This is the cost of removing the equipment and platform and cleaning up the ocean bed. The exact nature of reclamation requirements varies from one part of the world to another, but almost invariably the costs are very high, often much more than the original cost of the platform and facilities, particularly when oil storage facilities are a part of the structure.

Offshore platforms are often an oasis for marine life, as they offer small fish protection in the shallower, sunlit water depths. Offshore platforms, particularly in the Gulf of Mexico, are a popular destination for sport fishermen. Recognizing this benefit, government authorities sometimes allow offshore platforms to be removed from the seabed, towed to designated areas outside of shipping lanes, and sunk, forming artificial reefs. In rare instances, operators may be allowed to cut off the top of platforms to a certain water depth (perhaps 40 meters) and leave the substructure in place.

ACCOUNTING PROBLEMS RELATED TO OFFSHORE ACTIVITIES

The unique aspects of offshore physical activities and the extremely high costs of property acquisition, exploration, drilling, development, production, and reclamation, although not necessarily creating unique accounting problems, do compound and make more difficult some of the problems encountered in accounting for onshore operations. These complications are recognized in Oi5 and Reg. S-X Rule 4-10 and have been discussed in previous chapters of this book. In this chapter, we shall simply summarize those areas that deserve special consideration. References to the chapters where detailed discussions may be found are included.

Unproved Properties

The acquisition costs of offshore properties are accounted for in the same way as those of onshore leases. The bonus paid the state or federal government is capitalized, as are incidental acquisition costs. Offshore properties, especially federal leases, are large, and the bonus costs are unusually high, often exceeding $10 million. So the costs of unproved offshore leases are typically assessed on a property-by-property basis for successful efforts impairment (Chapter Seven). For full cost accounting, costs of acquiring unproved offshore property are usually excluded from the full cost amortization base (Chapter Nineteen).

Because such leases may be large, both in area and cost, Oi5.120 allows a portion of the leasehold cost to be transferred to proved property accounts if proved reserves are found on only a part of the lease and if exploration is continuing on the remainder of the property. Oi5.120 indicates that the allocable portion is to be "determined on the basis of geological structural features or stratigraphic conditions." This language suggests that a lease is *large* only if it is believed to have more than one structural feature to be explored.

Oi5.120 is silent about whether the allocation could be based on relative surface acreage, but that approach seems reasonable. If the successful exploratory well finds proved reserves in a structural feature under an estimated 5,000 acres on a largely unexplored 50,000-acre lease, then perhaps ten percent of the lease acquisition cost could reasonably be reclassified to proved property. However, if G&G studies indicate that the 50,000-acre lease contains only five geological structural features with possible oil and gas reserves under a total of 20,000 surface acres, then it would seem more reasonable to allocate 5/20ths, or 25 percent, of the lease acquisition costs to proved properties.

Support Facilities

When a company engages in offshore operations, the costs of acquiring support facilities and the operating costs of operating those facilities are likely to be much higher than for onshore facilities. Port facilities, docks, transportation vessels and helicopters, and supply facilities are likely to be very expensive. In addition, those facilities often service exploration, acquisition, drilling, development, and production activities. Thus, one of the major accounting considerations is to develop procedures to properly charge such costs to the appropriate activity. This is especially important because most operator-owned facilities are used in joint operations. Recognizing this problem, the Council of Petroleum Accountants Societies has issued several publications related to accounting procedures for offshore operations, for example: Bulletin No. 15, *Accounting Procedures Offshore, Joint Operations*; Bulletin No. 18, *Distribution of Boat and Fuel Expenses, Offshore Operations;* Bulletin No. 19, *Distribution of Helicopter Expenses*, *Offshore Operations*; and Bulletin No. 20, *Shore Base Facilities*, *Accounting Guidelines*. Although these bulletins are intended primarily for use in connection with joint operations, they provide guidance in classifying and recording costs and in allocating the costs to specific activities. As called for in Reg. S-X Rule 4-10(a)(17)(ii), the depreciation and amortization of such facilities, as well as the applicable operating costs, become acquisition, exploration, development, or production costs and are accounted for as such.

Geological and Geophysical Costs

The rules for capitalizing geological and geophysical exploration costs incurred offshore are identical to those for onshore activities, although offshore costs are likely to be larger. A full cost company capitalizes all such costs as part of the cost pool in the cost center, whereas a company using successful efforts accounting will treat all such costs as current expense at the time they are incurred.

Exploratory Drilling

Offshore exploratory drilling is likely to be much more expensive than onshore drilling to the same depth. As previously discussed, offshore platforms, barges, and ships must be used. Offshore rigs are expensive to construct, and high costs are incurred for moving the rigs and transporting materials, supplies, and the workforce. The cost of providing lodging and food for crews at offshore locations and constructing and maintaining onshore facilities such as docks, warehouses, and repair shops is very high. The question of allocating the expenses of service facilities was discussed previously.

As pointed out earlier, many offshore exploratory wells are drilled with no intention that the well be completed as productive, even if proved reserves are discovered. Such wells are *stratigraphic test wells* defined by Reg. S-X 4-10(a)(13) as

> a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intention of being completed for hydrocarbon production. This classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as (i) *exploratory-type* if not drilled in a proved area, or (ii) *development-type* if drilled in a proved area.

Costs of offshore exploratory wells are accounted for in exactly the same way as those of onshore exploratory wells. Thus, under the successful efforts method, wells that find proved reserves will be capitalized, and those that are unsuccessful will be charged to expense. A full cost company capitalizes all exploratory well costs. One troublesome question for successful efforts companies relates to evaluation wells.

Before production can begin, it is necessary to construct a permanent platform from which to drill development wells and to install production equipment and storage. Before the high costs of constructing the platform and drilling development wells can be justified, however, it is normally essential to drill evaluation wells (usually stratigraphic wells) to determine whether adequate reserves are present to justify the cost. As discussed in detail in Chapter Six, under Oi5.125 companies using the successful efforts method may continue to defer costs of stratigraphic test wells that find oil and gas reserves in an area requiring a major capital expenditure (usually additional test wells and a production platform) before production can begin, only as long as (1) the well has found a sufficient quantity of reserves to justify its completion had it not been simply a stratigraphic test well and (2) drilling of additional exploratory stratigraphic test wells is underway or firmly planned for the near future. Otherwise, the costs of the stratigraphic test well shall be assumed to be impaired, and the cost shall be charged to expense.

Development Costs

The same rules of capitalization apply to offshore development costs as to onshore costs. Again, a major difference is in the magnitude of costs incurred and in the substantial costs of service facilities that must be allocated to the various offshore activities. A second major difference is that offshore operations, from lease acquisition to first production, often take years rather than months.

Offshore development costs include the costs of stratigraphic test wells (whether or not successful) drilled into proved areas. Stratigraphic test wells are frequently drilled to assist in determining the most favorable location for the permanent platform.

Depreciation, Depletion, and Amortization

The estimate of the total quantity of proved reserves from an offshore project may depend on the drilling of wells over several years from the permanent platform. Production from the earlier wells may commence long before the entire drilling program is completed. Under both the successful efforts and full cost methods, this extended development period raises a question about the time at which both the capitalized acquisition, exploration, and development costs and the related proved reserves should enter into the DD&A calculation.

Oi5.126 and Reg. S-X Rule 4-10(c)(3)(ii) provide rules for transferring such costs to the amortization base for successful efforts companies and full cost companies, respectively, as previously addressed in Chapters Seventeen and Nineteen.

Removal and Restoration

One of the most interesting and important accounting problems related to offshore activities is the accrual of costs related to platform removal and reclamation as discussed in Chapter Twenty. A number of factors cause accounting policies related to removal and restoration to vary widely among companies. Requirements vary in different parts of the world, and international requirements have not been firmly established. In addition, because of the long (and often uncertain) period between the time of installation of a facility and its ultimate removal, it is difficult to estimate the total cost.

Production Costs

Offshore production costs are charged to expense as incurred. A major element of such expenses may be the cost of operating support facilities both onshore and offshore. An offshore production cost not found in onshore activities is the cost of transporting the oil or gas to shore by pipeline, barge, or ship. Reg. S-X Rule 4-10(a)(1)(c) points out that

> the oil and gas production function shall normally be regarded as terminating at the outlet valve on the lease or field storage tank; if unusual physical or operational circumstances exist, it may be appropriate to regard the production functions as terminating at the first point at which oil, gas, or gas liquids are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal.

Thus, the cost of transporting the product from the platform or well to shore and perhaps the costs of terminal facilities onshore are appropriately treated as production expenses.

Shared Facilities

It is not uncommon for the operator of a platform to sublet platform space or services to operators of other smaller platforms in the area. For example, the operator of a marginal field may enter into an agreement for a nearby platform to handle or process fluids, or for a nearby operator to provide daily oversight.

ENHANCED RECOVERY[134]

Oil and gas recovery methods may be grouped into two broad classifications: primary recovery and enhanced recovery. An inexact definition of primary recovery is that it embraces all production when the reservoir's natural drive mechanism (water drive, dissolved gas drive, or gas cap drive) is the only source of energy, causing the reservoir contents

[134] The authors acknowledge the contributions of ARCO engineer Mr. D. J. Charlton, former manager of the Dallas Projects Group, ARCO Resources Technology, to the section of this chapter dealing with the technical aspects of enhanced recovery.

to flow into the well bore.[135] Once in the well bore, primary production may (1) flow freely up the well, (2) be pumped up, or (3) be lifted up utilizing natural gas lift. Enhanced recovery represents the production that results from an artificial reservoir drive, such as water flooding or gas injections, causing the reservoir contents to flow into the well bore. Enhanced recovery methods are sometimes further divided into *secondary* and *tertiary* recovery.[136] The distinction between these two classes is also rather inexact. Although for purposes of this chapter the distinction is not important, a secondary recovery project is defined as the first installation of an artificial drive mechanism to force the reservoir contents into the well bore. Tertiary recovery projects are those involving installation of a second artificial drive mechanism.

The efficiency of a reservoir's primary drive mechanism is dependent on many factors: the physical geometry of the reservoir; the physical and chemical composition of the reservoir rock and fluids; the depth, temperature, and pressure of the reservoir; the physical characteristics of the wells penetrating the reservoir; and the historical manner in which the reservoir has been produced. In oil reservoirs, it is very rare for the recovery factor (the ratio of oil produced to original oil in place) to exceed 50 percent, and the average is probably around 25 to 30 percent. Enhanced oil recovery projects often result in a doubling of the recovery factor and occasionally result in total recovery factors in excess of 75 percent. Natural gas reservoirs routinely exceed 70 percent recovery factors and occasionally exceed 90 percent without any enhanced recovery techniques applied. Enhanced recovery efforts on gas reservoirs are typically targeting additional gas liquids or condensate contained in the gas rather than the gas itself.

Enhanced recovery methods are capital-intensive and usually require an extended period of time from the first investment until additional production occurs. Enhanced recovery techniques are not without risk. Projects may perform below expectations, despite supportive engineering studies prior to the projects' implementation.

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[135] Gravity can in rare instances be a significant natural drive mechanism.

[136] Secondary recovery is often viewed as water flooding, whereas more exotic recovery methods classified as tertiary recovery may be employed in some reservoirs that were never subjected to *secondary recovery*.

ENHANCED RECOVERY METHODS

Artificial stimulation of oil reservoirs has been used since the early part of this century. The early methods involved injection of water or natural gas into the reservoir. Later methods have included injection of chemicals, steam, and carbon dioxide (CO_2), and *in situ* combustion (under which a fire is started within the reservoir). A brief review of the most commonly encountered techniques will make the accounting problems more evident.

Water Injection

Water injection is a simple method of improving recovery from the reservoir and may actually be put into effect as soon as production is begun from the reservoir under *pressure maintenance* programs. If the water injection (called waterflooding) is begun before natural reservoir pressure declines significantly, it does not represent a true secondary recovery method. Water injection serves two functions: it provides a means for disposing of water produced from the reservoir along with the oil and gas, and it increases total productivity by flushing the oil out of the rock. The water is forced through properly located injection wells into the reservoir and through the reservoir rock into the productive wells, carrying oil along with it. *Waterflood* projects commonly use *five spot* patterns. A five-spot pattern is depicted in Figure 31-1.

Water injected (or reinjected) into the reservoir must be similar or identical to water found in the reservoir and must be clear, noncorrosive, and free of materials that might plug the oil-bearing formation. If water produced from the reservoir or other subsurface sources is used, it contains little oxygen, and very little treatment is required. However, if surface water is used, it may be high in oxygen content and also contain incompatible chemicals. Thus, the facilities needed for a water injection program may include not only injection wells and pumps, but also systems for deaeration, filtration, chemical treatment, and testing.[137]

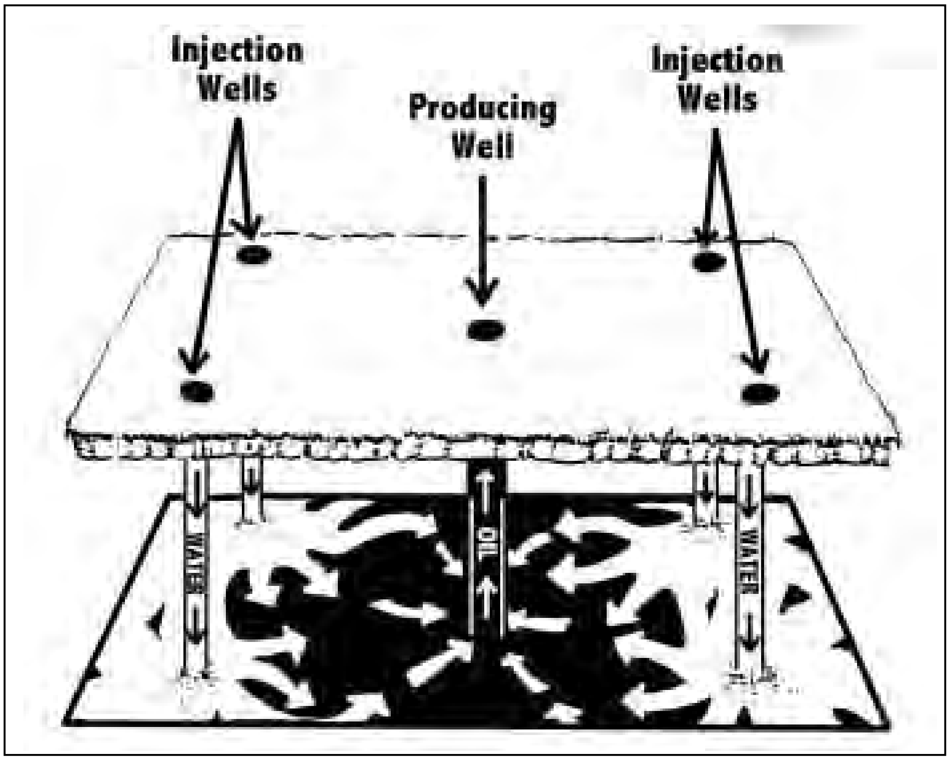
Chemical Injection

Since oil is generally more viscous than water, water can flow through a reservoir more easily. In waterflood situations, this can result in the injected water channeling past the oil, greatly reducing the effectiveness of the waterflood project. In some instances, reservoir and fluid conditions

[137]Deaeration reduces the water's oxygen content to reduce corrosion.

are such that viscosifiers, typically long-chain polymers, can be added to the water. The thickened water does not push past the oil as easily, resulting in better sweep efficiency of the oil in the reservoir. Due to the cost and quantity of chemical additives needed, and the narrow range of conditions where such projects are feasible, p*olymer floods*, as they are commonly known, are relatively rare.

Figure 31-1: Five-Spot Waterflood Pattern



Gas Injection

Gas injection was discussed in some detail in Chapter Eleven, but a recapitulation is in order here.

Gas produced from a reservoir can be reinjected into the reservoir when there is no market outlet or when the reinjection will increase the ultimate recovery of oil or condensate. When there is no pipeline to allow the sales of gas and regulatory authorities will not permit the flaring of gas, operators often reinject the gas. This allows the current production of the more valuable oil or condensate, and the gas can be produced at some future time when a pipeline exists. In some situations, the reinjection of gas maintains an oil reservoir's pressure above a certain critical threshold called the bubble point. It is dependent on the pressure, temperature, and chemical composition of the oil and gas in a particular reservoir. When the pressure is above the bubble point, all gas in the reservoir is absorbed in the crude oil and is said to be in solution. When pressure falls below the bubble point, gas bubbles out of the solution, much like the bubbles that form when a carbonated beverage is opened. If the reservoir pressure can be maintained above the bubble point, ultimate oil recoveries are generally much higher.

In gas reservoirs that contain condensate, the corollary to the bubble point is called the dew point. Above the dew point, all condensate in the reservoir exists as gas. When the reservoir pressure falls below the dew point, the condensate can liquefy in the reservoir, reducing the ultimate recovery of both condensate and gas. In a gas cycling operation, the lean gas (the resulting gas stream after it has passed through the separators and the condensate has been removed) is reinjected into the reservoir, where it maintains pressure and absorbs condensate, increasing the ultimate recovery.

In both of the cases illustrated here, the reinjected gas can be part or all of the production, or additional gas can be purchased and brought in to provide the necessary volume. At some point, the incremental recovery of oil or condensate does not cover the additional expense of the compressors and related facilities necessary for reinjection. At this point, reinjection ceases and the excess gas is sold. This is often called the *blowdown* phase.

Enriched Gas and Miscible Injection

Propane or butane mixed with natural gas, called *enriched gas*, or carbon dioxide (CO_2) can be injected into an oil reservoir. Enriched gas or CO_2 acts as a miscible solvent when it contacts the oil. The oil absorbs the rich gas or CO_2, reducing the oil's viscosity and enhances the oil's ability to flow. The reduced viscosity and increased pressure from injection increase the ultimate recovery factor. The solvent is usually removed during separation and reinjected. The cost of propane or butane limits the number of enriched gas projects. Miscible CO_2 projects are also expensive but are relatively common in areas where they have been shown to work well, particularly in West Texas and New Mexico. Rather than inject only CO_2, a common technique used is WAG (*water and gas* or *water* *alternating gas*), in which a volume of CO_2 is injected, followed by a volume of water to displace it. This achieves the desired effect at a lower cost.

Thermal Stimulation

In reservoirs containing oil with high viscosity (generally *heavy oil* with high density, i.e., API gravity below 20 degrees), it may be possible to stimulate production by heating the contents of the reservoir. This may be accomplished by injecting hot water or steam into the reservoir in a manner similar to that shown in the Figure 31-1 illustration. The water or steam lowers the viscosity and flushes the oil to the producing well. Steam may be continuously injected into the reservoir, although sometimes a cyclic steam injection process (also called *huff-and-puff*) is used. Under the huff-and-puff process, steam is injected periodically into the reservoir. The steam condenses, and the resulting hot water thins the oil and drives it to the well bore. After the steam has been condensed, another injection of steam is made. This huff-and-puff cycle continues until the reservoir is heated. Continuous steam flooding and huff and puff steam injection are quite common in fields containing heavy oil near Bakersfield, California. Such steam flooding operations provide significant markets for natural gas. The gas is burned in co-generation facilities that generate (1) heat to convert water to steam and (2) electricity used onsite or sold to a local electric utility.

Another thermal process is *in situ* combustion. Air is injected into the reservoir, and a fire is ignited, burning some of the oil in the reservoir. The fire heats the reservoir, allowing the heavy oil to flow into the producing well. *In situ* combustion, or *fireflooding,* is normally used in a reservoir only when other stimulation methods are not feasible, as most *in situ* projects have had relatively poor results.

Other Methods

The enhanced recovery methods discussed above represent the techniques used on the vast majority of projects around the world, but not all. Other types that might be encountered include heating of the reservoir by electrical currents, introduction of anerobic bacteria that convert a portion of the hydrocarbons to gases to repressurize the reservoir, or repressurization using nitrogen or combustion flue gases.

ACCOUNTING PROBLEMS RELATED TO ENHANCED RECOVERY

The two major accounting problems related to enhanced recovery are determining (1) when the related reserves are to be included in the reserve disclosures and the amortization calculation and (2) how to account for material injected into the reservoir. Costs incurred to install enhanced recovery facilities, including the cost to drill injection wells, are properly capitalized as wells and related equipment and facilities and are amortized as the related reserves are produced. In computing amortization of enhanced recovery facilities, a successful efforts company will include such costs in the property or field's total developed costs to be amortized over the cost center's total proved developed reserves (which have been increased by the incremental proved developed reserves added by the enhanced recovery operation).

Reg. S-X Rule 4-10(a)(2), (3), and (4) place limits on recognizing proved reserves from enhanced recovery techniques:

> . . . Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based. . . . Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved. . . . Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

The reference to *in the area and in the same reservoir* seems to mean simply *in the same reservoir*, based on SEC staff interpretations that such language, consistent with paragraph (2)(ii), limits the comparable program to one in the same reservoir. As noted in Chapter Sixteen, the Society of Petroleum Engineers' definition of proved undeveloped reserves requires only that such testing or operations have been successful in a reservoir in the immediate area with similar rock and fluid properties. However, that *industry definition* of proved undeveloped reserves remains unacceptable to the SEC and for financial reporting under FAS 25, which requires that the SEC definition in Reg. S-X Rule 4-10 be used.

For a full cost company, the cost of enhanced recovery facilities is amortized as part of the total cost of the countrywide cost pool. It is appropriate to exclude the capital costs of recovery projects from the amortization calculation until the reserves to be added by the project have been classified as proved or when the project is determined to be unsuccessful.

The problems of accounting for materials injected into the reservoir were discussed in Chapter Thirteen. If none of the materials are recoverable, these costs may be charged to expense at the same time they are injected, or if they are deemed to be of benefit over the life of the entire project, the costs may be capitalized and amortized as wells and related facilities. If some part of the material is recoverable, the portion of cost related to the recoverable product may be treated separately as an inventory item whose cost is not charged immediately to expense and is not amortized. As the injected product is deemed to be produced, its costs are then charged to expense. Another approach is to treat the cost of the recoverable material in the same way as that of the nonrecoverable material. Both approaches are used in practice.

It is almost certain that, in the long run, oil added through enhanced recovery will become a more important part of the United States oil supply.

TAX INCENTIVES FOR ENHANCED RECOVERY

As discussed at the end of Chapter Twenty-Six, Section 43 of the Internal Revenue Code provides for an enhanced oil recovery tax credit equal to 15 percent of qualified EOR costs for tertiary recovery projects in U.S. oil fields. Tax basis (and related IDC deductions and future depreciation deductions) is reduced by the amount of the EOR tax credit. If a taxpayer's tax rate is 35%, a $100,000 EOR tax credit is partially offset by taking away $100,000 in deductions, increasing taxes by $35,000 whereby a $100,000 EOR tax credit ultimately reduces taxes by $65,000, not $100,000.

Chapter Thirty-Two

DERIVATIVES AND HEDGE ACCOUNTING

BACKGROUND

Just as pipeline deregulation permanently changed the gas industry in the late 1980s and early 1990s, derivatives have changed the entire petroleum industry in the 1990s. *Derivatives* are financial instruments whose values are *derived from* the value of an underlying asset, reference rate, or index. Derivatives commonly being used by oil and gas companies include futures, forwards, options, and swaps. Derivatives have received a great deal of attention from the media and regulators as several companies have incurred significant losses, and the usage of these instruments has become more common. However, derivatives designed specifically for the energy industry have existed for several years. The New York Mercantile Exchange (NYMEX) crude oil and natural gas futures contracts have been in existence since 1983 and 1990, respectively.

Derivatives are used by exploration and production, marketing, pipeline, refining, and utility companies as well as large industrial consumers. Energy derivatives are widely used to hedge risks associated with the volatility of oil and gas prices. Investors and companies that wish to speculate on the movement of commodity prices also use them.

COMMON TYPES OF COMMODITY-BASED DERIVATIVE INSTRUMENTS

FUTURES

A *futures contract* in a commodity, such as oil or gas, is an exchange-traded legal contract to buy or sell a standard quantity and quality of a commodity at a specified future date and price. Both crude oil and natural gas futures contracts are traded on the NYMEX, with other exchanges developing similar contracts. The standard NYMEX crude oil futures contract is for 1,000 bbls for delivery in Cushing, Oklahoma.

The standard NYMEX natural gas futures contract is for 10,000 mmBtu for delivery at the Henry Hub in southern Louisiana. Beginning in August 1995, the Kansas City Board of Trade (KCBT) offered natural gas futures contracts for 10,000 mmBtu for delivery at the Waha Hub in west Texas.

Futures contracts can be used to protect against losses on existing assets or anticipated transactions from adverse price changes. Futures contracts may also be used to speculate on the upward and downward price movements of the underlying commodity. Futures contracts are subject to regulation by the Commodities Futures Trading Commission (CFTC).

The purchaser of a futures contract has a *long position*, and the seller of a futures contract has a *short position*. Buyers/sellers of futures contracts can easily liquidate their positions by selling/buying an offsetting contract for the same delivery month. The vast majority of crude oil and gas futures contracts are settled in this manner, as opposed to delivering or receiving oil or gas at the exchanges' delivery points. Buyers/sellers may also settle their futures positions by exchanging for physicals, as discussed in Chapter Twelve.

Buyers and sellers typically execute their transactions through a commodity futures brokerage firm. Initial margin deposits of cash or cash equivalents are required for futures contracts. If the value of the futures contract decreases by a significant amount, the customer must deposit additional funds to restore the original margin account amount. The exchange on which the futures contract is bought or sold acts as a clearinghouse between buyers and sellers of futures contracts, guarantees contract performance, and assumes all counterparty credit risk.

FORWARD CONTRACTS

Like a futures contract, a *forward contract* in a commodity is a legal contract between two parties to purchase and sell a specific quantity and quality of a commodity at a specified price, with delivery and settlement at a specified future date.[138] Oil and gas forward contracts, however, are not traded on regulated commodity exchanges. The contracts are privately negotiated agreements referred to as *over-the-counter* (*OTC*) *contracts*. Consequently, they lack the liquidity and minimal credit risk exposure offered by exchange-traded futures contracts. However, forward contracts are more flexible than futures contracts because they can be tailored to

[138]A forward is similar to *prepaids* described in Chapter Twenty-Two, but for prepaids the cash is paid up front and presumably discounted for the time value of money.

specific quantities, settlement dates, and delivery points. Like futures contracts, forward contracts can be used for both hedging and speculating.

OPTIONS

Option contracts give the holder the right, but not the obligation, to buy (*call*) or sell (*put*) a specified item at a fixed price (*exercise* or *strike price*) during a specified period (*exercise period*). The buyer (*holder*) pays a nonrefundable fee (*premium*) to the seller (*writer*). Options may be either exchange-traded (such as NYMEX options on the NYMEX crude oil futures contract) or OTC contracts. OTC options expose the holder to counterparty default. Options can also be used for both hedge and speculative purposes.

Call Example. On June 1, 2000, Optimistic Oil, Inc., pays Pessimistic, Inc., a $500 premium for an over-the-counter call option to buy from Pessimistic by May 1, 2001, 1,000 barrels of West Texas Intermediate (WTI) crude oil at $24 per barrel. If by May 1, 2000, the spot price of WTI remains less than $24 per barrel, Optimistic's call is unexercised and expires as worthless. Alternatively, assume that on April 15, 2001, the spot price is $26 per barrel, at which time Optimistic, as holder, exercises the call option, paying $24,000 to Pessimistic (the call option writer) in return for the 1,000 barrels worth $26,000. In that case, the call option, costing Optimistic $500, would provide, upon exercise, a profit to Optimistic of $1,500 before transaction expenses. Pessimistic loses a net $1,500 from writing the exercised call option. Usually option contracts are settled on a net cash basis without physical delivery of the commodity.

Put Example. Assume that GoingUp, Inc., sold an OTC put option for 1,000 barrels of WTI crude at $22 per barrel exercisable on or before May 1, 2001. GoingDown, Inc., pays a $400 premium to buy the put option. It gives GoingDown the right to sell 1,000 barrels to GoingUp for $22,000. On March 18, 2001, assuming the WTI price had fallen to $20/bbl, GoingDown exercises the put option, selling 1,000 barrels of WTI to GoingUp for $22,000, for a net profit of $1,600 after the $400 cost of the premium.

The option buyer's risk is limited to the premium paid. Because an option is a right and not an obligation, the holder can profit from favorable price movements in the item underlying the option. The writer of an option bears the risk of an unfavorable change in the price of the item underlying the option. Similarly, the writer of a *naked option* (i.e., the writer does not own the item underlying the option) is exposed to losses substantially greater than the premium received.

Naked Option Example. Paul Pessimistic writes a naked call option on crude oil at a price of $20 per barrel and receives a premium of $1 per barrel. War breaks out in the Middle East, the price of crude oil goes up to $45 per barrel, and the option is exercised. Paul Pessimistic must buy crude oil at $45 per barrel, sell it for $20 per barrel, and take a large loss (after the $1/bbl premium) of $24 per barrel.

There are several terms unique to options. Depending on whether a *call* option's strike price is less than, equal to, or greater than the commodity's current price, the call option is considered to be *in-the-money*, *at-the-money*, or *out-of-the-money*, respectively. In contrast, when a *put* option's strike price is less than, equal to, or greater than the commodity's price, then the put option is considered to be *out-of-the-money*, *at-the-money*, or *in-the-money*, respectively.

The value of an option is derived primarily from its intrinsic and time values as well as the underlying commodity's volatility. The extent to which an option is *in-the-money* is its *intrinsic value*. Consequently, intrinsic value is never a negative amount. The *time value* of an option represents the portion of the premium in excess of the option's intrinsic value due to the possibility that the option can move *in-the-money* during the exercise period. *American options* can be exercised at any time during the exercise period. *European options* can be exercised only at the end of the exercise period. *Volatility* refers to the amount a commodity's price fluctuates. A more volatile commodity is more likely to move *in-the-money* during the exercise period. Higher intrinsic values, longer exercise periods, and greater price volatility of the underlying commodity result in higher option premiums and risks.

SWAPS

Swaps are contracts between two parties to exchange variable and fixed-rate payment streams based on a specified contract principal or notional amount. For instance, two companies may enter into a natural gas price swap which requires one company (the fixed-price payor) to pay a fixed price and another company (the variable-price payor) to pay based upon a published gas index or futures contract settlement price. The volume of gas (e.g., 1,000 mmBtu per month for six months) used to calculate the variable and fixed-rate payment is the *contract principal* or *notional amount*. The settlement amount of these contracts is typically calculated as the difference between the fixed and variable prices multiplied by the notional volume. A net payment is made to one of the parties. Swap contracts are more flexible than futures contracts because they can be tailored for specific quantities, settlement dates and locations. Swap agreements are OTC contracts and therefore expose the parties to *counterparty credit risk*, i.e., the other party may be unable to pay or honor the contract. However, parties to swap agreements may require margin deposits. Swaps are used primarily for hedging purposes or to alter the terms of an existing agreement.

Swap Example. Lockin, Inc., wants to lock in the price of gas for 2001 and 2002, whereas Skyhigh, Inc., is optimistic that gas prices will rise substantially but had previously agreed to sell much of its gas production at a fixed price to a co-generation facility over the next few years. Lockin and Skyhigh agree to a gas price swap for 2001 and 2002 for 10,000 mmBtu per day whereby Skyhigh pays cash to Lockin equal to the excess of a $2.50/mmBtu fixed price over an average monthly spot price published by a third party. So if such average spot price were $1.90/mmBtu, Skyhigh pays Lockin $0.60/mmBtu. If that same month, Lockin sold 10,000 mmBtu at the $1.90 average spot price, the swap with Skyhigh raises the effective price for Lockin to the $2.50 fixed price desired by Lockin. Meanwhile, Skyhigh received $2.50/mmBtu under its fixed price sales contract, but the swap obligation reduced Skyhigh's effective price to the $1.90/mmBtu spot price. Payments are made at the end of the month following the month of gas sales.

If the published average spot price for January 2001 sales is $3.00 per mmBtu, Lockin pays Skyhigh by February 28, 2001, $155,000 (calculated as $.50/mmBtu x 10,000 mmBtu/day x 31 days). If Lockin sold 10,000 mmBtu at $3.00/mmBtu, then the Swap reduces Lockin's effective price to $2.50/mmBtu. If the published average spot price for June 2001 sales is $2.10/mmBtu, then Skyhigh pays Lockin by July 31, 1999, $120,000 (calculated as $.40/mmBtu x 10,000 mmBtu/day x 30 days).

The swap effectively locks in a $2.50/mmBtu price for Lockin on 10,000 mmBtu/day for two years, whereas Skyhigh effectively receives a price that fluctuates with spot gas prices.

USES OF DERIVATIVES IN THE ENERGY INDUSTRY

Exploration and production companies which sell their production at index prices can protect some portion of their oil and gas reserves from downward price movements by effectively fixing the sales price of their reserve production using futures, forwards, and swaps. Producers can create *floors* by purchasing put options that guarantee minimum oil or gas prices. Exploration and production companies can also create *collars* by selling a call option and buying a put option on their production. A collar effectively fixes the realized price between the strike prices of the put and call options. When the premium received for the call equals the premium paid for the put, the collar is known as a *zero-cost collar*.

Floor Example. Lowrisk, Inc., buys a put option for $3,000 to sell 10,000 WTI oil barrels at $24.00/bbl when the spot price of such oil is $26.00/bbl. If the spot price drops to $22.00 per barrel, Lowrisk's production would be sold at $22.00 per barrel except that Lowrisk can exercise the put option to sell 10,000 barrels for $24.00/bbl. After the $3,000 cost of the put ($.30 per contract barrel), Lowrisk has created a $23.70 net *floor* price for 10,000 barrels of its production.

Zero-Cost Collar Example. Suppose Lowrisk also sold a call option for $3,000 allowing the holder to buy from Lowrisk 10,000 barrels at $28.50/bbl. Since Lowrisk receives a $0.30/bbl call premium offset by the $0.30/bbl cost of the put option, Lowrisk has created a ceiling price of $28.50/bbl for 10,000 barrels of production. If the price goes above $28.50 per barrel, the call holder exercises the call and pays only $28.50/bbl to Lowrisk for the 10,000 barrels. By buying a put for $3,000 and selling a call for $3,000 to create a zero-cost collar, Lowrisk has reduced the price range for 10,000 barrels of production to a range of $24.00 to $28.50 per barrel. If prices are very volatile, both options might be exercised over the exercise time period whereby Lowrisk would sell 10,000 barrels at $24.00/bbl and an additional 10,000 barrels at $28.50 per barrel, for an average price of $26.25 per barrel.

Companies enter into the transactions described above for several reasons, including the following:

- to maintain a desired level of profitability during periods of falling prices,
- to achieve a desired internal rate of return on investments, and
- to obtain additional financing from financial institutions.

Derivatives are also widely used by marketing, pipeline, refining, and utility companies as well as large industrial consumers. A gas marketing company, which buys gas from producers at spot prices, may offer its customers fixed-price sales contracts. The gas marketing company is exposed to price risk because an increase in the supply spot prices in excess of the fixed sales contract prices will result in losses. The marketing company can effectively fix its supply cost by purchasing futures contracts or using other derivative financial instruments. Likewise, pipeline, refining, and utility companies as well as large industrial consumers can effectively fix their fuel costs by using derivative contracts.

RISKS ASSOCIATED WITH DERIVATIVES

Although derivatives can be effectively used to protect companies from adverse commodity price movements, significant risks can be associated with these financial instruments.

PRICE RISK

Because of the volatility of oil and gas prices, producers are exposed to the risk that prices will decline. If derivatives are used to hedge this exposure, it is important that the risk management activities be performed by personnel with a good understanding of a company's price risks and the terms of the derivatives used to reduce the risk. Poor risk-management strategy development can result in increased exposure to volatile oil and gas prices.

CREDIT RISK

Similar to other financial instruments, derivatives expose a company to credit risk. *Credit risk* is the risk that a loss may occur from the failure of another party (counterparty) to perform according to the terms of a contract. It includes not only the net payable or receivable outstanding, but also the cost of replacing a derivative contract if the counterparty defaults. Counterparty credit risk is further concentrated when companies enter into multiple derivative contracts with the same counterparty or counterparties in the same geographic location or industry. Credit risk is generally lower if the derivative is an exchange-traded contract. Exposure to credit risk can be further minimized by requiring collateral or margin deposits.

LIQUIDITY RISK

Liquidity risk results from the inability to easily purchase or sell derivative contracts in the required quantities at a fair price. Fair prices may not be available when there are large discrepancies between the *bid* price (buyer's price) and the *asked* price (seller's price). Exchange-traded derivatives are generally more liquid than over-the-counter derivatives.

CORRELATION RISK

Correlation risk is the risk that the commodity price in the derivative contract will not move in tandem with the commodity price being hedged. Consequently, the increase in the value of a derivative transaction might not fully offset the decrease in the value of the hedged item, or vice versa. Accordingly, when deciding whether to hedge a risk, it should be determined whether there is an expected high correlation between anticipated changes in the market value of the hedging instrument and in the market value of the hedged item, and whether the correlation is likely to continue throughout the hedging period.

BASIS

Basis is the difference between the spot price of the hedged item and the price of the hedging instrument. The basis is sometimes referred to as the *spread*. Because the prices received for oil and gas vary due to location, quality, local supply/demand conditions, and other factors, the commodity price of the hedge contract frequently does not equal the spot price received for the production. For instance, the spread between San Juan Basin gas index prices and the NYMEX gas futures prices varied from approximately $+0.10/mmBtu to $-1.19/mmBtu from January 1993 to December 1995.

ACCOUNTING GUIDANCE

In June 1998, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards No. 133, “Accounting for Derivative Instruments and Hedging Activities” (“FAS 133” or “the Standard”). FAS 133 is one of the most controversial and far-reaching accounting standards issued in recent years. It represents a comprehensive framework of accounting rules that standardizes and creates uniform accounting for all derivatives. Under the Standard, all derivatives must be recognized on the balance sheet at fair value with the offsetting entry related to unrealized gains and/or losses reflected either as part of current earnings or in other comprehensive income, a component of stockholders' equity. These modifications eliminate the practice of synthetic-instrument and off-balance sheet accounting. The ultimate goal of the FASB was to increase the visibility of derivatives and require that hedge ineffectiveness be recorded in earnings. Adoption of the Standard will cause an increase in the size of the balance sheet accounts used to record the fair value of derivatives and increase earnings and equity volatility for many exploration and production entities. The Standard applies to all entities, all types of derivatives and is effective for all fiscal quarters of fiscal years beginning after June 15, 2000.

In June 2000, the FASB issued FAS 138, *Accounting for Certain Derivative Instruments and Certain Hedging Activities, an Amendment to FASB Statement No. 133*. For E&P companies, a notable provision of FAS 138 is to allow certain contracts to not be considered derivatives. Contracts that contain net settlement provisions may qualify for the normal purchases and normal sales exception if it is probable at inception and throughout the term of the individual contract that the contract will not settle net and will result in physical delivery.

As a result of the complexity of FAS 133, the FASB created the Derivatives Implementation Group ("DIG"). The DIG is a task force to assist the FASB in answering questions that companies must address when they implement and interpret FAS 133. The objective in forming the group was to establish a mechanism to identify and resolve significant implementation questions in advance of adoption of the standard by many companies. The responsibilities of the DIG are to identify practice issues that arise from applying the requirements of FAS 133 and to advise the FASB on how to resolve those issues. The DIG will remain in place to address matters in application at least through the end of fiscal year 2000. At the time of this publication, there are many uncertainties pertaining to the application of the Standard that remain unresolved. The issues addressed by the DIG and approved by the FASB should be read in conjunction with the information included within this chapter.

The accounting guidance in place until the implementation of FAS 133 occurs is driven by the concepts contained in FAS 80, "Accounting for Futures Contracts." Chapter Thirty-One of the 4th edition of this book contains a discussion of derivatives under the parameters of accounting guidance in a pre-FAS 133 marketplace. The discussion for the remainder of this chapter focuses on the requirements of FAS 133.

DEFINITION OF A DERIVATIVE

A derivative under FAS 133 can be defined as a financial instrument or other contract that possess *all* three of the following characteristics:

1. Value changes by direct reference to (1) one or more underlyings and (2) one or more notional amounts or payment provisions or both,
2. No initial net investment (or a small investment for time value), and
3. Settled net or by delivery of an asset that is readily convertible to cash.

Key to this definition are the concepts of *underlying*, *notional amount*, and *payment provision*. An *underlying* in a derivative is a specified commodity price, interest rate or security price or some other variable. An underlying may be a price or rate of interest but not the asset or liability itself. Accordingly, the underlying generally will be the referenced index that determines whether or not the derivative has a positive or negative value.

A *notional amount* is a number of barrels of crude oil, mmBtu's of natural gas, pounds, bushels, currency units, shares or other units specified in a contract. The notional amount represents the second half of the equation that goes into determining the settlement amount or amounts under the derivative contract. Accordingly, the settlement of a derivative is determined by the interaction of the notional amount with the underlying. This interaction may consist of simple multiplication or it may involve a more complex formula.

A *payment provision* specifies a fixed or determinable settlement that is to be made if the underlying behaves in a specified manner. For the energy industry, the payment provision is the most problematic component as the commodity (such as crude oil and natural gas) is produced and sold in liquid markets. In essence, there are three ways to meet the net settlement requirement as follows:

1. Net settlement explicitly required or permitted by the contract (i.e., symmetrical liquidating damage clause),

2. Net settlement by a market mechanism outside the contract (i.e. futures exchange), or
3. Delivery of a derivative or an asset that is readily convertible to cash.

Thus based on these concepts, the definition of a derivative has been expanded to include not only the typical financial instruments that have been viewed in the past as derivatives (discussed at the beginning of this chapter) but may also include some traditional physical commodity contracts which do not meet the normal purchase and sale exclusion provided for in FAS 133. FAS 138 allows contracts that contain net settlement provisions to qualify for the normal purchases and normal sales exception if it is probable at inception and throughout the term of the individual contract that the contract will not settle net and will result in physical delivery.

EXCLUSIONS

Certain exclusions to the parameters of the definition of a derivative under FAS 133 exist. These exclusions relate to normal purchases and sales, contingent consideration resulting from a business combination, certain insurance contracts, and employee compensation arrangements that are indexed to an entity's own stock and classified as part of stockholders' equity. Contracts, which meet the definition of a derivative and qualify for one of these exclusions, are not subject to FAS 133.

EMBEDDED DERIVATIVES

An *embedded derivative* is a provision in a contract through its implicit or explicit terms that contains the characteristics of a free-standing derivative which ultimately affect the cash flows or value of other exchanges required by a contract. Thus, the combination of a *host* contract and an embedded derivative is referred to as a hybrid instrument. Examples of an embedded derivative include a purchase or sale contract subject to a cap, floor or collar. An embedded derivative should be separated from the host contract and accounted for separately in the financial statements if all of the following criteria are met:

1. The embedded characteristic in the contract would meet the definition of a derivative,

2. Characteristics and risks of the embedded derivative are not clearly and closely related to the host contract, and
3. The host contract is not measured at fair value.

Judgement is required to interpret the phrase "clearly and closely related," which is not defined in FAS 133. "Clearly and closely related" implies the economic features of an embedded derivative and the host contract are somewhat interdependent and the fair value of the embedded derivative and the host contract are impacted by the same variables and vice versa.

TYPES OF HEDGES

The income statement recognition of changes in the fair value of a derivative will depend on the intended use of the derivative. If the derivative does not qualify as a hedging instrument or is not designated as such, the gain or loss on the derivative must be recognized currently in earnings. To qualify for hedge accounting, the derivative must qualify either as a *fair value hedge*, *cash flow hedge*, or *foreign currency hedge*.

A *fair value hedge* represents the hedge of an exposure to changes in the fair value of an asset, liability or an unrecognized firm commitment that is attributable to a particular risk. An example of a fair value hedge would be a forward contract pertaining to an unrecognized firm commitment (fixed price sales and purchase contracts) or an interest rate swap contract associated with fixed rate debt. A fair value hedge is reflected in the financial statements at market value each reporting period and the associated unrealized gain or loss incurred with respect to such instrument is included in earnings. Changes in the fair value of the corresponding unrecognized firm commitment or asset/liability being hedged is also recognized in the financial statements each reporting period. As a result, both the income statement and balance sheet of an organization is increased for these transactions. The only component that would affect net income, in any given reporting period, would be any ineffectiveness identified as part of the effectiveness assessment made by the organization.

A *cash flow hedge* is a hedge of an exposure to variability in cash flows that is attributable to a particular risk which may be associated with an existing recognized asset or liability (floating rate debt) or a forecasted transaction (future production of crude oil or natural gas). Some common examples include the use of futures, swaps or costless collar arrangements associated with future crude oil and natural gas productions or an interest rate swap associated with variable rate debt. A cash flow hedge is reflected in the financial statements at market value each reporting period and the associated unrealized gain or loss incurred with respect to such instrument is included in other comprehensive income, a component of stockholders' equity. The amount that is deferred in other comprehensive income is always the *lesser of* (in absolute value terms) (1) the estimated changes in the expected future cash flows of the hedged item that are attributable to the hedged risk or (2) the cumulative gain or loss on the derivative instrument. The corresponding forecasted transaction or recognized asset and liability is not reflected/adjusted in the financial statements. The only component that would affect net income, in any given reporting period, would be any ineffectiveness identified as part of the effectiveness assessment made by the organization.

FAS 133 generally retained FAS 52 hedge accounting provisions. In this regard, FAS 133 includes a narrow scope of transactions for which hedge accounting may be applied to foreign currency/operations activities.

A *foreign currency hedge* is the hedge of a foreign currency exposure to an unrecognized firm commitment, an available-for-sale security, a forecasted transaction or a net investment in a foreign operation. A foreign currency hedge can have the dynamics of a fair value transaction, cash flow transaction or foreign currency hedge of a net investment in a foreign operation depending on the nature of the underlying physical transaction(s). Foreign currency hedges are accounted for in a manner consistent with the general provisions of a fair value hedge or cash flow hedge as previously described.

EFFECTIVENESS

Certain criteria must be met for a derivative financial instrument to fall within one of the hedging categories described above. Some of the criteria are similar to the concepts utilized for the determination of hedge accounting at present, while others are a formalization of a process which may already be in place. First, an entity must indicate what it is doing with the derivative financial instrument through formal documentation of the hedge relationship and risk management objective and strategy at the beginning of the contract term. The formal documentation encompasses a specific designation of the hedge instrument and related item, the nature of the risk being hedged and the method of assessing effectiveness. The hedging item should be consistent with the respective risk management policy and expected to be highly effective at inception and on an ongoing basis throughout the term of the contract.

The FASB declined to quantify "highly effective;" however, the DIG provided interpretive guidance with respect to this matter in DIG Issue E6. The assessment of effectiveness is required to be performed at least every three months and whenever financial statements or earnings are reported to the public. The method for assessing effectiveness should be included as part of the documentation requirements prior to the beginning of the designation of the hedging relationship. Hedge effectiveness must be achieved initially and on an ongoing basis. As such, the measurement of hedge effectiveness is prospective as well as retrospective. Ordinarily, it is expected that an entity would assess effectiveness for similar hedges in a similar manner; use of different methods for similar hedges should be justified.

Effectiveness allows an entity to utilize hedge accounting; however, ineffectiveness must still be measured and recorded in the financial statements. If a derivative has been determined to be highly effective, some ineffectiveness is likely to occur and some gain or loss reflected in earnings. Items which may generate ineffectiveness include (1) different maturity or repricing dates, (2) different underlying (e.g., hedging jet fuel inventory with heating oil futures), (3) location and quality differentials (San Juan Basin gas versus NYMEX or sweet versus sour barrels) and (4) credit differences. As it relates to cash flow hedges, the amount deferred in other comprehensive income is the lesser of (in absolute value terms) (1) the estimated changes in the expected future cash flows of the hedged item that are attributable to the hedged risk and (2) the cumulative gain or loss on the derivative instrument. In essence, there is a limitation of the amounts pertaining to unrealized gains and/or losses that may be accumulated in other comprehensive income. Therefore, the cumulative gain or loss on the derivative in excess of the estimated changes in expected future cash flows will be recorded in the income statement as ineffectiveness.

Any changes that an entity might make to its method of assessing effectiveness would have to be justified and would be applied prospectively by a discontinuance of the existing hedging relationship and a new designation of the relationship through the use of the improved method. In addition, if an enterprise changes the method of assessing effectiveness on a hedged item, the enterprise should also change the method of assessment for similar hedges.

Discontinuance of Hedge Accounting

Under the parameters of FAS 133, discontinuance of hedge accounting would transpire in two situations as follows:

1. Failure to meet any of the qualifying hedge criteria and
2. Derivatives were to expire or be sold, terminated, exercised or simply dedesignated as a hedging instrument.

Disclosures

The disclosure requirements in financial statements under FAS 133 are quite extensive in that it has expanded qualitative disclosures to include the objective and strategy, risk management policy and description of hedged items. In addition, FAS 133 expanded the disclosure pertaining to derivatives to include the amount of ineffectiveness reflected in earnings, the earnings impact from discontinued hedges, the amount of gains and losses included in other comprehensive income to be included in earnings within the next twelve months and the purpose of derivatives that do not qualify as a hedging instrument.

INTERNAL CONTROLS

Derivatives can be effectively used as a part of a company's risk-management program to reduce exposure to adverse changes in commodity prices. However, a poorly managed and controlled program can expose a company to unexpected losses. In order to ensure that a risk-management program meets management's objectives, a company's derivative activities should be approved by its board of directors, monitored by a risk management committee, and executed by a risk-management staff. Additionally, a company's accounting department must ensure that all derivative transactions are properly accounted for and disclosed. More specific duties and controls are described in Figure 32-1.

FIGURE 32-1: COMMON CONTROL ACTIVITIES

BOARD OF DIRECTORS

- Obtain a thorough understanding of the company's risk profile and the derivatives used to manage the risks
- Gain understanding of the organization's internal controls over derivatives
- Approve the company's risk management policy regarding the following:

  - Risk management strategy
  - Types of derivatives utilized,
  - Members of the risk management committee, and
  - Derivative transaction dollar, volume, and term limits

RISK-MANAGEMENT COMMITTEE

- Develop appropriate control policies and procedures
- Approve all new margin accounts and OTC counterparties
- Develop a detailed risk-management plan (annually, monthly, weekly)
- Authorize trading representative (TR) in risk management to conduct trades
- Ensure that each TR's trading limits are told to all counterparties and brokers
- Prepare monthly reports to evaluate the risk-management department's actual performance vs. the risk-management plan

RISK-MANAGEMENT DEPARTMENT

- Execute derivative transactions consistent with risk-management plan (transaction approved by member of risk-management committee)
- Complete trade ticket and forward to accounting
- Compare counterparty confirmation to trade ticket and resolve differences
- Prepare daily position report and forward to risk-management committee and accounting
- Prepare monthly cash flow estimates for treasury department
- Approve and verify receivable and payable invoices

ACCOUNTING DEPARTMENT

- Maintain accounting records of all transactions
- Compare accounting records to confirmation from the counterparty
- Reconcile accounting records to TR's daily position report
- Prepare receivable invoices and verify payable invoices
- Coordinate with treasury department and TR to request refunds of excess margin accounts
- Journalize appropriate accounting entries
- Ensure that proper disclosures are made in the company's financial statements

Chapter Thirty-Three

RISK MANAGEMENT

This chapter provides an overview of risk management, its importance to the success of E&P organizations, and its significant impact on petroleum accounting.

The importance of risk management is pervasive in the global business community. One recent study of risk management included interviews with directors and senior managers. In the 12 months preceding the survey, 86 percent of the boards and audit committees of the companies surveyed had formally reviewed risk management and control. In this group, 50 percent reported that their organization had faced at least some risk management or control failure that had impacted its performance. Additional market research revealed that 80 percent of the managers contacted believe risk management is fundamental to business success and 37 percent had suffered a significant loss as a result of unexpected risks. It is evident that an understanding of the business environment and inherent risks is a critical component of strategic control decisions.

As discussed in prior chapters, petroleum accounting can be very complex. Driving the ever-increasing complexity are the needs of E&P organizations for risk management in the broadest business sense. While accounting simplicity is often desirable, simplicity should not override the need to manage risk. Conversely, management courts disaster if risk management solutions (e.g., mergers and exploring in new territories) ignore the risk hazards that arise when the necessary accounting becomes seemingly impossible, impractical, or inadequately controlled. Successful risk management must include an appropriate assessment of the accounting and information needs of a company and its stakeholders.

RISK

What is risk? The *Merriam Webster Dictionary* defines risk as "exposure to possible loss or injury." In business, risks are everywhere. Managers talk about exploration risk, competitive risk, market risk, financial risk, operating risk, technology risk, environmental risk, regulatory risk, litigation risk, political risk, etc. But managers are rarely clear, even in their own minds, about just what they mean. The term *risk* is used in many different ways, depending upon the type of risk under discussion.

THREE RISK FRAMEWORKS FOR THE PETROLEUM ACCOUNTANT

For the petroleum accountant, there are three general frameworks in which the term *risk* is defined differently:

- An industry or business framework in which *risks are uncertain future events which could influence the achievement of the organization's objectives, including strategic, operational, financial and compliance objectives. Risk defined in this way can be linked to return. An organization takes risks in order to pursue opportunities to earn returns for its owners; striking a balance between risk and return is key to maximizing shareholder wealth*,
- An internal control framework in which *risk* generally refers to exposure to hazards and information error, and
- A financial audit framework in which *risk* refers to *audit risk* (the possibility of misstating the independent auditor's report) consisting of (1) *inherent risk* (the susceptibility of a financial assertion to misstatement), (2) *control risk* (risk that a material misstatement in the financials will not be detected by the company's internal control system), and (3) *detection risk* (risk that the independent auditor will not detect material misstatements).

When addressing risk management, the accountant needs to keep the appropriate framework in mind. This chapter focuses on the business perspective of risk and how risk management involves much more than a simple focus on internal controls.

Risk in a Business Framework

The business framework acknowledges that risk exposes an organization to opportunities, hazards, and uncertainties and is inherent in business. Indeed, one could say that the business of business is to buy, manage, and exploit risks. For example, buying an oil and gas lease is paying for risks, i.e., exposing the organization to the possibility of finding valuable oil and gas or drilling an expensive dry hole. E&P entities don't shy away from taking risks, they go out and buy them! In that sense, risk taking is an asset; and like all assets, it needs to be managed.

For example, an E&P company will buy many leases expecting to drill some successful wells, some dry holes, and to discover enough oil and gas which can be sold at economical prices enabling a profit from the overall exploration and production effort. The company buys the leases (and the risks) on its assessment that the opportunities will outweigh the hazards. Buying several leases and entering into joint venture agreements reduces the risk of little or no success. However, there is always exposure to the unexpected: a well blowout or a local citizenry that rallies political forces to keep a company's new offshore discovery from being produced.

Risk is inherent in virtually every business action and inaction. Risk cannot be eliminated entirely and is a natural part of business success. In fact, the risk-averse organization is frequently one that does not survive, as new markets, new products, and new responses quickly pass it by.

Risk in an Internal Control Framework

The internal control framework standard is documented in *Internal Control—Integrated Framework*, the report commissioned by the Committee of Sponsoring Organizations of the Treadway Commission, commonly called the COSO Report.[139] The COSO Report defines internal control as:

> a process, effected by an entity's board of directors, management and other personnel, designed to provide reasonable assurance regarding the achievement of objectives in the following categories:
>
> - Effectiveness and efficiency of operations,
> - Reliability of financial reporting, and
> - Compliance with applicable laws and regulations.

As defined, internal control is not a back-room function left to internal auditors, but a process involving all employees, from senior management on down.

The internal control objectives do not, per se, mirror a company's overall objectives, e.g., internal control is not charged with maximizing shareholder value, but internal control does play a role in meeting a

[139]The COSO organizations were the American Institute of Certified Public Accountants, the American Accounting Association, the Financial Executives Institute, the Institute of Internal Auditors, and the Institute of Management Accountants.

company's overall objectives. For example, efficient operations contribute to maximizing shareholder value.

Risks within the COSO internal control framework refer to risks that the three internal control objectives will not be fully achieved, i.e.,

- Possible material misstatement(s) of financial statements,
- Possible reduction(s) in the effectiveness and efficiency of operations, and
- Possible violation(s) of laws and regulations.

The internal control framework focuses on minimizing hazards, including material misstatement(s) of financial information.

AREAS OF RISK

Broad areas of risk exist for every company and its stakeholders. Risks must be recognized to be managed, and recognition requires an awareness of stakeholders who may be impacted by the identified risks.

A stakeholder is defined as any group or individual that can affect or is affected by achievement of a company's objectives. Stakeholders include shareholders, creditors, employees, governments, the communities in which a company operates, and indirectly the world when a company's activities impact general prosperity. The long-term viability of a company is dependent in part on intelligent, balanced service to its stakeholders.

Strategic risks arise from corporate decisions on mergers, acquisitions, geographic focus, and other strategic actions. *Financial* risks exist, e.g., with respect to capital costs, information systems, and employee fraud. *Operational* risks occur in property acquisition, exploration, development and production. *Compliance* risks exist in attempting to conduct business within the myriad of government laws, regulations, and contracts dealing with exploration, production, employees, customers, taxation, environmental safety, etc.

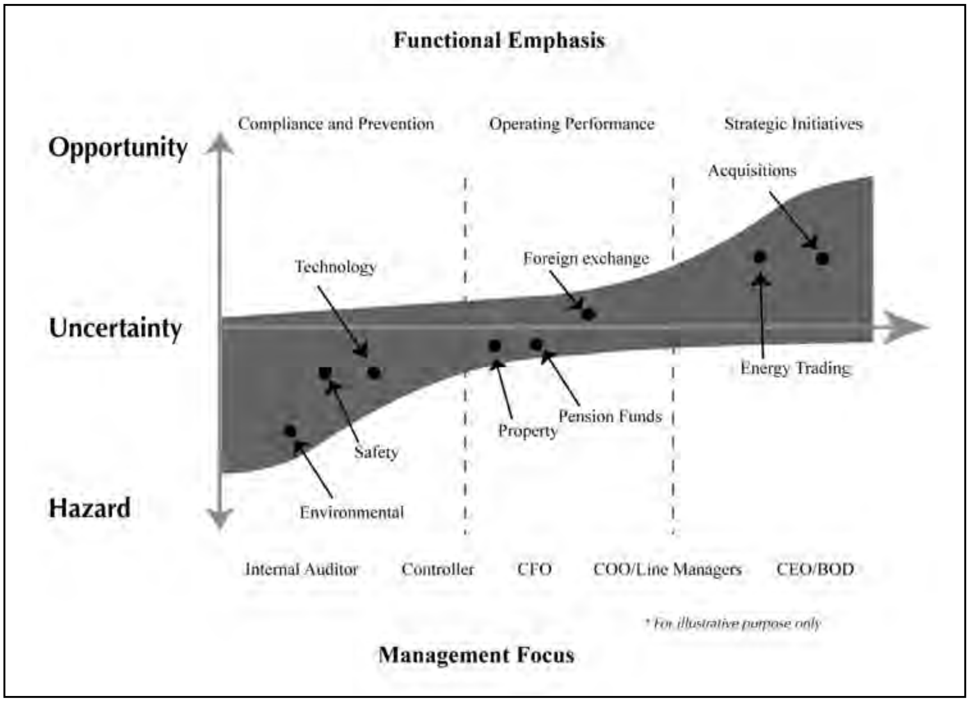
The petroleum industry continues to encounter enormous changes and each change brings a new basket of risks to be identified and addressed. Consider globalization, a development wherein many U.S. companies have sought opportunities in areas of the world where opportunities exist for major discoveries, but where kidnappings, guerilla warfare, and even hired killings may be among the recognized hazards of doing business.

RISK MANAGEMENT — *INTERNAL CONTROL AND MORE*

Like *risk*, the term *risk management* is used in many ways. For example, an insurance agent is said to provide *risk management*. The term can also be defined narrowly as an element of risk assessment, which is a component of internal control. However, *risk management* entails a much broader range of activities, which expose the company to hazards, uncertainties and opportunities.

Risk management addresses the full spectrum of risk in terms of (1) compliance and prevention (focusing on hazards), (2) operating performance, and (3) strategic initiatives (focusing on opportunities) as illustrated in Figure 33-1.

Figure 33-1: Addressing the Full Spectrum of Risk



FROM THE BACK ROOM TO THE BOARD ROOM

Historically, risk management has often been viewed as an insurance management or an internal audit function. With acknowledgement of risk as inherent in all business functions, organizations must accept the fact that risk management is the responsibility of all employees, starting at the highest levels of management. Figure 33-2 highlights the changes in perspective as the role of risk management becomes less a "back room" function, and more a corporate-wide function starting at the very top of the company.

Figure 33-2: The Changing Perception of Risk Management

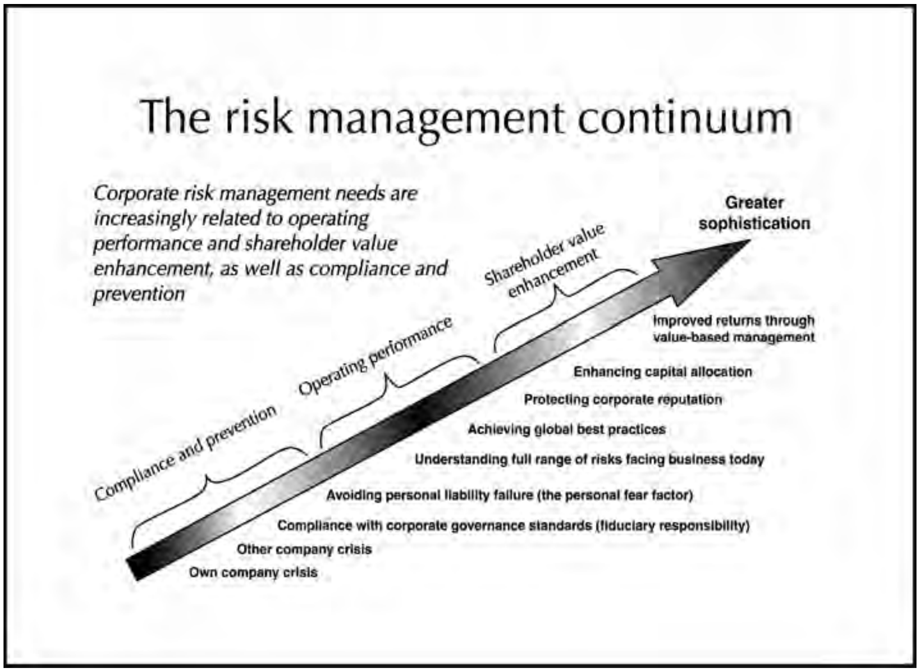
from the BACK ROOM	to the BOARD ROOM
• Low / operational level. Risk monitoring is a function of the internal auditors	• **The CEO's job (with Board oversight)**
• Risk as a negative factor to be controlled	• **Risk as opportunity**
• Risk managed in organizational silos	• **Risk managed in an integrated, enterprise-wide fashion**
• Responsibility for risk management is delegated to lower levels	• **Risk management responsibility accepted by senior and line management**
• Risk measurement is subjective	• **Quantification of risk**
• Unstructured and divergent risk management functions	• **Risk management is built into all corporate management systems**

Risk management goes beyond crisis management and compliance to address issues of business continuity protection and shareholder value enhancement (Figure 33-3). Upward movement along this risk management continuum is critical for a company striving to enhance shareholder value.

A company focused on crisis management and compliance often uses band-aid responses. Risk focus may be lacking and symptoms are frequently treated rather than addressing the root causes of crises. Such a company may only be maintaining compliance with corporate governance standards (fiduciary responsibility) and trying to avoid personal liability failure.

A company focused on business continuity protection is positioned to identify and correct root causes of surprises and problems. This company is proactive and has an enterprise-wide business risk assessment philosophy, including a risk identification strategy. By understanding and evaluating business strategy risks, this company can achieve global best practices and protect corporate reputation.

Figure 33-3: The Risk Management Continuum



Ideally, a company should address risk management from the perspective of enhancing shareholder value while balancing the needs of all stakeholders. This type of company fully embraces the concepts of enterprise-wide risk measurement and manages risks as an integral part of the business, allowing the framework to “come alive.” This approach will enhance capital allocation and improve returns through value-based management.

INTERNAL CONTROL

The COSO report describes internal control as having five components:

1. The control environment,
2. Risk assessment,
3. Control activities,
4. Information and communication, and
5. Monitoring.

Control Environment

The control environment sets the tone for an organization and influences the control consciousness of its people. It is the foundation for all other components of internal control, providing discipline and structure. Control environment factors include the integrity, ethical values and competence of the entity's people; management's philosophy and operating style; the way management assigns authority and responsibility, and organizes and develops its people; and the attention and direction provided by the board of directors.

Risk Assessment

Risk assessment is the identification and analysis of the risks, current and future, faced by an organization. Management must identify and analyze risks, quantify their magnitude, and project their likelihood and possible consequences.

Management must determine how much risk is tolerable, along with the possible cost, and strive to manage risk within determined levels of risk appetite. An example is a company's tolerance for price changes. Assume oil sells for $20 per barrel, management expects prices to rise, but the company could not survive if prices fell to $12 and the two-year outlook dropped to the $12 range. Despite the expectation of rising prices, management may deem it prudent to use derivatives (discussed in Chapter Thirty-Two) to hedge against falling oil prices. The derivatives' cost may be in the form of cash (via purchase of a put option) or in the form of foregoing gains from price increases (via derivative instruments that create a price floor and a price ceiling).

Managers need clear objectives and a real understanding of risks in their area of the business. In many cases today, risk evaluations are done informally and controls are assumed to be adequate. Managers need to be more accountable to the criticality of understanding risk.

A manager must understand business components and business processes to understand risk and their hazards. These components and processes set the framework for identifying the potential risks of a business. Once a manager understands the business components and processes, then the question "What can go wrong?" can be asked, documented and responses established.

A tool that helps with documentation is a risk matrix. A risk matrix lists the major business components/processes across the top and the related major risks down the side. An example is given in Figure 33-4.

Figure 33-4: Risk Matrix Example

BUSINESS FUNCTION —> Business Function Ranking (based on Exposure) (listed in order of importance from left to right)	Automated Control Systems 1	Safety Systems 2	Remote Monitor Systems 3	Measurement Systems 4
RISKS:				
SYSTEM AVAILABILITY AND RECOVERY				
1. Operational impacts or inefficiencies resulting from insufficient support and recovery systems (redundant equip, critical spares, backups, etc.)	High	High	High	High
SYSTEM CHANGE MANAGEMENT				
2. Unauthorized or erroneous software, configuration, or hardware changes may be implemented adversely effecting business activities.	High	High	High	High
3. Changes may not be adequately reviewed and tested compromising system integrity and / or effectiveness.	High	High	High	High
4. Implementation of changes is not adequately planned or scheduled resulting in undue risk to person / property or increase operational disruption.	Medium	Medium	Medium	Medium
ACCESS SECURITY MANAGEMENT				
5. Process control facilities may not be secure, safe or operationally reliable.	Medium	Medium	Medium	Medium
6. Systems and data may not be secured in accordance with company policies exposing critical or sensitive applications or data to inappropriate modification, disclosure or use.	Medium	Medium	Medium	Medium
ENVIRONMENTAL CONTROL & TRAINING				
7. Damage to PC systems or networks or operational disruption resulting from inadequate environmental controls or inadequate operator training.	Medium	Medium	Low	N/A
8. Compromise of facility safety or operations due to failure of environmental support systems or inadequate training.	Medium	Medium	Low	N/A

When determining the risks, management should gain an understanding of all risks and weigh the value of existing controls against the implementation of new ones. Once the risks have been identified, they should be evaluated as to probability of occurrence and potential impact on the company.

Control Activities

Control policies and procedures must be established and executed to minimize identified risks in line with management's objectives and directives.

Information and Communication

Surrounding the risk assessment and control activities are information and communication systems necessary to conduct the activities.

Monitoring

Internal control processes must be monitored and modified as necessary to allow the internal controls to react dynamically as conditions change.

ORCA: RISK MANAGEMENT ARCHITECTURE

Building a common risk management methodology requires objectives, risks and controls to be aligned throughout the organization. An effective architecture will turn hazards into opportunities, promote individual empowerment, and create an integrated environment linking people, processes, strategy and leadership. Each of these tasks combines to send a powerful message to the investing community.

PricewaterhouseCoopers has developed a systematic, structured approach to risk management based on four key elements known as "ORCA." ORCA represents objectives, risks, controls/processes, and alignment.

Objectives

In order to identify risks in terms of opportunities, hazards and uncertainties, it helps to start by identifying objectives, both at the corporate/stakeholder level and at divisional and operational levels. Business objectives drive the activities of an organization and therefore the most critical risks. The stakeholders are both external and internal, thus requiring a holistic awareness. These objectives are interdependent, increasingly interrelated, and designed for long-term success.

Risks

Risks within a business framework were previously defined as *uncertain future events which could influence the achievement of the organization's objectives, including strategic, operational, financial and compliance objectives*. The risks category entails risk assessment similar to that for the internal control framework, but applying the broader definition of risk to include opportunities. The opportunity perspective of risk recognizes that good things can and do happen. This could include new markets, new innovations, or new systems. Actions required to make this happen include researching best practices, finding potential from occurrence of negative events and creating competitive advantage.

Controls/Processes

Controls/processes includes the five interrelated components of internal control previously described.

Alignment

Alignment integrates all levels within the organization. It mobilizes individual and collective action towards achieving objectives. Alignment ensures only value-adding objectives are pursued.

This methodology can be transformed into a risk management architecture by building the ORCA process into the business. All types of risks can be managed by consistent, instinctive and recurring application of the ORCA principles.

BUILDING AN ORCA RISK MANAGEMENT ARCHITECTURE

Eight elements are necessary to build an ORCA risk management architecture:

1. Acceptance of a risk management framework as a focal point and basis for common language,
2. Senior management commitment,
3. Risk management/change process owner,
4. Process,
5. Communication,
6. Training,
7. Reinforcement through human resources mechanisms, and
8. Monitoring by management and internal audit.

Development and acceptance of a risk management framework provides the cornerstone for assessing and harnessing risk. Senior management commitment will help ensure that proper resources are expended and risk management policies are put into place.

There must be a risk management process owner, such as a Chief Risk Officer (CRO), who can track the progress of managing risk and communicate results to senior management. The CRO and staff should inform the business units of the latest risk management tools and techniques, identify best practices, manage risk interdependencies across business units, and monitor aggregate risk exposure. An important objective of the CRO is to ingrain the management of risk into the values and culture of the organization.

Training must be conducted to understand risk and how to employ processes to manage it. To create accountability within the methodology, human resource metrics should be aligned to reflect risk management aspects. And finally, management should monitor each of these steps with substantial assistance from internal audit.

IMPORTANCE OF RISK MANAGEMENT TO THE E&P INDUSTRY

The E&P industry was built on risk management. Wells deplete; new reserves must be found; dry holes happen. As described in Chapter Two, the typical E&P company must focus on adding reserve value to be successful. There are many ways of managing risks to add reserve value, e.g.:

- Acquisition of lease rights in promising areas to improve opportunities for exploratory success,
- Use of the best suitable exploration technology,
- Spreading risk and gaining expertise via joint venture arrangements,
- Hedging oil and gas prices in line with management directives,
- Sophisticated approaches to valuing reserves,
- Strong engineering oversight of production,
- Geological, engineering, and management personnel with technical, financial and risk management perspectives, and
- Creative and assorted financing arrangements to provide capital at the lowest cost for the degree of retained risks of property ownership.

Given the (a) core nature of the industry to explore, (b) volatility of petroleum prices and exploratory success, (c) industry issues of globalization and global warming, and (d) rapid and substantial technology changes, a strong risk management process throughout an E&P company should be of significant benefit and importance.

IMPACT OF RISK MANAGEMENT ON PETROLEUM ACCOUNTING

Risk management drives many of the events and transactions that petroleum accountants must address, e.g.:

- Use of joint venture arrangements to manage risk at the expense of complicating petroleum accounting,
- Globalization to enhance corporate opportunities at the expense of requiring additional or specialized accounting systems and policies for new foreign locations,

- Creative financing arrangements, such as conveyances of volumetric production payments, necessitating special petroleum accounting,
- For the sake of risk management, the development and use of standardized forms, contracts, and joint venture protocols, such as COPAS accounting exhibits, gas balancing agreements, EDI standards, joint venture audits, and material transfer accounting procedures,
- Enhanced, secure internet communications of accounting transactions,
- Hedge accounting,
- Internal and external financial and tax reporting, and
- Internal auditing.

Petroleum accounting is fundamentally a key element of risk management. As a company's risk management program increases in importance and sophistication, so too should the company's accounting department.

QUANTIFICATION OF RISKS

Sophistication will require petroleum accountants to play a key role in quantifying risks in financial terms. Such quantification has become more practical as computer technologies advance. Just how important is it to quantify risks? Consider the following statement in *Against the Gods: The Remarkable Story of Risk* by Peter L. Bernstein:

> ***More than any other development, the quantification of risk defines the boundary between modern times and the rest of history.***

APPENDIX 1: REGULATION S-X RULE 4-10
(as of January 1, 2000)

Per Regulation S-X Rule 4-10's preface, the regulation prescribes the financial accounting and reporting standards for "oil and gas producing activities" of SEC registrants. The subsections are listed below for easier reference.

App. Page	**Subsection**	
1-2	-------	**Preface**
1-2	4-10(a)	**Definitions**
1-2	4-10(a)(1)	Oil and gas producing activities
1-3	4-10(a)(2)	Proved oil and gas reserves
1-4	4-10(a)(3)	Proved developed oil and gas reserves
1-4	4-10(a)(4)	Proved undeveloped reserves
1-5	4-10(a)(5)	Proved properties
1-5	4-10(a)(6)	Unproved properties
1-5	4-10(a)(7)	Proved area
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1-5	4-10(a)(9)	Reservoir
1-5	4-10(a)(10)	Exploratory well
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1-8	4-10(c)	**Full Cost Method**
1-15	4-10(d)	**Income Taxes**
Addendum:		
1-16		**Excerpts from Reg. S-K and the SEC's Codification of Financial Reporting Releases**

Preface

210.4-10 Financial accounting and reporting for oil and gas producing activities pursuant to the Federal securities laws and the Energy Policy and Conservation Act of 1975.

This section prescribes financial accounting and reporting standards for registrants with the Commission engaged in oil and gas producing activities in filings under the federal securities laws and for the preparation of accounts by persons engaged, in whole or in part, in the production of crude oil or natural gas in the United States, pursuant to Section 503 of the Energy Policy and Conservation Act of 1975 (42 U.S.C. 6383) ("EPCA") and section 11(c) of the Energy Supply and Environmental Coordination Act of 1974 (15 U.S.C. 796) ("ESECA"), as amended by section 505 of EPCA. The application of this section to those oil and gas producing operations of companies regulated for rate-making purposes on an individual-company-cost-of-service basis may, however, give appropriate recognition to differences arising because of the effect of the rate-making process.

Exemption. Any person exempted by the Department of Energy from any record-keeping or reporting requirements pursuant to section 11(c) of ESECA, as amended, is similarly exempted from the related provisions of this section in the preparation of accounts pursuant to EPCA. This exemption does not affect the applicability of this section to filings pursuant to the federal securities laws.

Definitions

(a) *Definitions.* The following definitions apply to the terms listed below as they are used in this section:

(1) *Oil and gas producing activities.*

(i) Such activities include:

(A) The search for crude oil, including condensate and natural gas liquids, or natural gas ("oil and gas") in their natural states and original locations.

(B) The acquisition of property rights or properties for the purpose of further exploration and/or for the purpose of removing the oil or gas from existing reservoirs on those properties.

(C) The construction, drilling and production activities necessary to retrieve oil and gas from its natural reservoirs, and the acquisition, construction, installation, and maintenance of field gathering and storage systems—including lifting the oil and gas to the surface and gathering, treating, field processing (as in the case of processing gas to extract liquid hydrocarbons) and field storage. For purposes of this section, the oil and gas production function shall normally be regarded as terminating at the outlet valve on the lease or field storage tank; if unusual physical or operational circumstances exist, it may be appropriate to regard the production functions as terminating at the first point at which oil, gas, or gas liquids are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal.

(ii) Oil and gas producing activities do not include:

(A) The transporting, refining and marketing of oil and gas,

(B) Activities relating to the production of natural resources other than oil and gas,

(C) The production of geothermal steam or the extraction of hydrocarbons as a by-product of the production of geothermal steam or associated geothermal resources as defined in the Geothermal Steam Act of 1970, or

(D) The extraction of hydrocarbons from shale, tar sands, or coal.

(2) *Proved oil and gas reserves.* Proved oil and gas reserves are the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements, but not on escalations based upon future conditions.

(i) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes:

(A) that portion delineated by drilling and defined by gas-oil and/or oil-water contacts, if any; and

(B) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.

(ii) Reserves which can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the "proved" classification when successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

(iii) Estimates of proved reserves do not include the following:

(A) oil that may become available from known reservoirs but is classified separately as "indicated additional reserves",

(B) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors,

(C) crude oil, natural gas, and natural gas liquids, that may occur in undrilled prospects, and

(D) crude oil, natural gas, and natural gas liquids, that may be recovered from oil shales, coal, gilsonite and other such sources.

(3) *Proved developed oil and gas reserves.* Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as "proved developed reserves" only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

(4) *Proved undeveloped reserves.* Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage shall be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive

formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

(5) *Proved properties.* Properties with proved reserves.

(6) *Unproved properties.* Properties with no proved reserves.

(7) *Proved area.* The part of a property to which proved reserves have been specifically attributed.

(8) *Field.* An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas-of-interest, etc.

(9) *Reservoir.* A porous and permeable underground formation containing a natural accumulation of producible oil and/or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

(10) *Exploratory well.* A well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or gas in another reservoir, or to extend a known reservoir. Generally, an exploratory well is any well that is not a development well, a service well, or a stratigraphic test well as those items are defined below.

(11) *Development well.* A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

(12) *Service well.* A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for in-situ combustion.

(13) *Stratigraphic test well.* A drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intention of being completed for

hydrocarbon production. This classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as (i) "exploratory-type," if not drilled in a proved area, or (ii) "development-type," if drilled in a proved area.

(14) *Acquisition of properties.* Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

(15) *Exploration costs.* Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(i) Costs of topographical, geographical and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, these are sometimes referred to as geological and geophysical or "G&G" costs.

(ii) Costs of carrying and retaining undeveloped properties, such as delay rentals, ad valorem taxes on properties, legal costs for title defense, and the maintenance of land and lease records.

(iii) Dry hole contributions and bottom hole contributions.

(iv) Costs of drilling and equipping exploratory wells.

(v) Costs of drilling exploratory-type stratigraphic test wells.

(16) *Development costs.* Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(i) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.

(ii) Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.

(iii) Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems.

(iv) Provide improved recovery systems.

(17) *Production costs.*

(i) Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

(A) Costs of labor to operate the wells and related equipment and facilities.
(B) Repairs and maintenance.
(C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
(D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
(E) Severance taxes.

(ii) Some support equipment or facilities may serve two or more oil and gas producing activities and may also serve transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production costs, as appropriate. Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs are not production costs but also become part of the cost of oil and gas produced along with production (lifting) costs identified above.

Successful Efforts Method

(b) A reporting entity that follows the successful efforts method shall comply with the accounting and financial reporting disclosure requirements of Statement of Financial Accounting Standards No. 19, as amended.

[Paragraphs (c)—(h), were removed, and paragraphs (i) and (j) redesignated as (c) and (d) in Release No. 33-7300, May 31, 1996, effective July 15, 1996, 61 F.R. 30397.]

Full Cost Method

(c) *Application of the full cost method of accounting.* A reporting entity that follows the full cost method shall apply that method to all of its operations and to the operations of its subsidiaries, as follows:

(1) *Determination of cost centers.* Cost centers shall be established on a country-by-country basis.

(2) *Costs to be capitalized.* All costs associated with property acquisition, exploration, and development activities (as defined in paragraph (a) of this section) shall be capitalized within the appropriate cost center. Any internal costs that are capitalized shall be limited to those costs that can be directly identified with acquisition, exploration, and development activities undertaken by the reporting entity for its own account, and shall not include any costs related to production, general corporate overhead, or similar activities.

(3) *Amortization of capitalized costs.* Capitalized costs within a cost center shall be amortized on the unit-of-production basis using proved oil and gas reserves, as follows:

(i) Costs to be amortized shall include

(A) all capitalized costs, less accumulated amortization, other than the cost of properties described in paragraph (ii) below;

(B) the estimated future expenditures (based on current costs) to be incurred in developing proved reserves; and

(C) estimated dismantlement and abandonment costs, net of estimated salvage values.

(ii) The costs of investments in unproved properties and major development projects may be excluded from capitalized costs to be amortized, subject to the following:

(A) All costs directly associated with the acquisition and evaluation of unproved properties may be excluded from the amortization computation until it is determined whether or not proved reserves can be assigned to the properties, subject to the following conditions:

(1) Until such determination is made, the properties shall be assessed at least annually to ascertain whether impairment has occurred. Unevaluated properties whose costs are individually significant shall be assessed individually.[1] Where it is not practicable to individually assess the amount of impairment of properties for which costs are not individually significant, such properties may be grouped for purposes of assessing impairment. Impairment may be estimated by applying factors based on historical experience and other data such as primary lease terms of the properties, average holding periods of unproved properties, and geographic and geologic data to groupings of individually insignificant properties and projects. The amount of impairment assessed under either of these methods shall be added to the costs to be amortized.

(2) The costs of drilling exploratory dry holes shall be included in the amortization base immediately upon determination that the well is dry.

(3) If geological and geophysical costs cannot be directly associated with specific unevaluated properties, they shall be included in the amortization base as incurred. Upon complete evaluation of a property, the total remaining excluded cost (net of any impairment) shall be included in the full cost amortization base.

(B) Certain costs may be excluded from amortization when incurred in connection with major development projects expected to entail significant costs to ascertain the quantities of proved reserves attributable to the

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[1]The SEC believed that for full cost accounting "individually significant" property would generally have costs of more than 10% of the cost center's net book value as expressed in an SEC Codification of Financial Reporting Releases excerpt on page App. 1-17.

properties under development (e.g., the installation of an offshore drilling platform from which development wells are to be drilled, the installation of improved recovery programs, and similar major projects undertaken in the expectation of significant additions to proved reserves). The amounts which may be excluded are applicable portions of (1) the costs that relate to the major development project and have not previously been included in the amortization base, and (2) the estimated future expenditures associated with the development project. The excluded portion of any common costs associated with the development project should be based, as is most appropriate in the circumstances, on a comparison of either (i) existing proved reserves to total proved reserves expected to be established upon completion of the project, or (ii) the number of wells to which proved reserves have been assigned and total number of wells expected to be drilled. Such costs may be excluded from costs to be amortized until the earlier determination of whether additional reserves are proved or impairment occurs.

(C) Excluded costs and the proved reserves related to such costs shall be transferred into the amortization base on an ongoing (well-by-well or property-by-property) basis as the project is evaluated and proved reserves established or impairment determined. Once proved reserves are established, there is no further justification for continued exclusion from the full cost amortization base even if other factors prevent immediate production or marketing.

(iii) Amortization shall be computed on the basis of physical units, with oil and gas converted to a common unit of measure on the basis of their approximate relative energy content, unless economic circumstances (related to the effects of regulated prices) indicate that use of units of revenue is a more appropriate basis of computing amortization. In the latter case, amortization shall be computed on the basis of current gross revenues (excluding royalty payments and net profits disbursements) from production in relation to future gross revenues, based on current prices (including consideration of changes in existing prices provided only by contractual arrangements), from estimated production of proved oil and gas reserves. The effect of a significant price increase during the year on estimated future gross revenues shall be reflected in the amortization provision only for the period after the price increase occurs.

(iv) In some cases it may be more appropriate to depreciate natural gas cycling and processing plants by a method other than the unit-of-production method.

(v) Amortization computations shall be made on a consolidated basis, including investees accounted for on a proportionate consolidation basis. Investees accounted for on the equity method shall be treated separately.

(4) *Limitation on capitalized costs*.

(i) For each cost center, capitalized costs, less accumulated amortization and related deferred income taxes, shall not exceed an amount (the cost center ceiling) equal to the sum of:

(A) The present value of estimated future net revenues computed by applying current prices of oil and gas reserves (with consideration of price changes only to the extent provided by contractual arrangements) to estimated future production of proved oil and gas reserves as of the date of the latest balance sheet presented, less estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves computed using a discount factor of ten percent and assuming continuation of existing economic conditions; plus

(B) the cost of properties not being amortized pursuant to paragraph (c)(3)(ii) of this section; plus

(C) the lower of cost or estimated fair value of unproven properties included in the costs being amortized; less

(D) income tax effects related to differences between the book and tax basis of the properties referred to in paragraphs (c)(4)(i)(B) and (C) of this section.

(ii) If unamortized costs capitalized within a cost center, less related deferred income taxes, exceed the cost center ceiling, the excess shall be charged to expense and separately disclosed during the period in which the excess occurs. Amounts thus required to be written off shall not be reinstated for any subsequent increase in the cost center ceiling.

(5) *Production costs.* All costs relating to production activities, including workover costs incurred solely to maintain or increase levels of

production from an existing completion interval, shall be charged to expense as incurred.

(6) *Other transactions.* The provisions of paragraph (h) of this section, "Mineral property conveyances and related transactions if the successful efforts method of accounting is followed,"[2] shall apply also to those reporting entities following the full cost method except as follows:

(i) *Sales and abandonments of oil and gas properties.* Sales of oil and gas properties, whether or not being amortized currently, shall be accounted for as adjustments of capitalized costs, with no gain or loss recognized, unless such adjustments would significantly alter the relationship between capitalized costs and proved reserves of oil and gas attributable to a cost center. For instance, a significant alteration would not ordinarily be expected to occur for sales involving less than 25 percent of the reserve quantities of a given cost center. If gain or loss is recognized on such a sale, total capitalized costs within the cost center shall be allocated between the reserves sold and reserves retained on the same basis used to compute amortization, unless there are substantial economic differences between the properties sold and those retained, in which case capitalized costs shall be allocated on the basis of the relative fair values of the properties. Abandonments of oil and gas properties shall be accounted for as adjustments of capitalized costs; that is, the costs of abandoned properties shall be charged to the full cost center and amortized (subject to the limitation on capitalized costs in paragraph (b) of this section).[3]

(ii) *Purchases of reserves.* Purchases of oil and gas reserves in place ordinarily shall be accounted for as additional capitalized costs within the applicable cost center; however, significant purchases of production payments or properties with lives substantially shorter than the composite productive life of the cost center shall be accounted for separately.

(iii) *Partnerships, joint ventures and drilling arrangements.*

(A) Except as provided in subparagraph (c)(6)(i) of this section, all consideration received from sales or transfers of properties in connection with partnerships, joint venture operations, or various other forms of

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[2] The reference to deleted paragraph (h) is presumed to mean the FASB *Current Text* paragraphs Oi5.133 through Oi5.138 on conveyances under successful efforts accounting which replace (h) as indicated in Reg. S-X Rule 4-10(b).

[3] The limitation on capitalized costs appears in Reg. S-X Rule 4-10(c)(4).

drilling arrangements involving oil and gas exploration and development activities (e.g., carried interest, turnkey wells, management fees, etc.) shall be credited to the full cost account, except to the extent of amounts that represent reimbursement of organization, offering, general and administrative expenses, etc., that are identifiable with the transaction, if such amounts are currently incurred and charged to expense.

(B) Where a registrant organizes and manages a limited partnership involved only in the purchase of proved developed properties and subsequent distribution of income from such properties, management fee income may be recognized provided the properties involved do not require aggregate development expenditures in connection with production of existing proved reserves in excess of 10% of the partnership's recorded cost of such properties. Any income not recognized as a result of this limitation would be credited to the full cost account and recognized through a lower amortization provision as reserves are produced.

(iv) *Other services.* No income shall be recognized in connection with contractual services performed (e.g., drilling, well service, or equipment supply services, etc.) in connection with properties in which the registrant or an affiliate (as defined in §210.1-02 (b)) holds an ownership or other economic interest, except as follows:

(A) Where the registrant acquires an interest in the properties in connection with the service contract, income may be recognized to the extent the cash consideration received exceeds the related contract costs plus the registrant's share of costs incurred and estimated to be incurred in connection with the properties. Ownership interests acquired within one year of the date of such a contract are considered to be acquired in connection with the service for purposes of applying this rule. The amount of any guarantees or similar arrangements undertaken as part of this contract should be considered as part of the costs related to the properties for purposes of applying this rule.

(B) Where the registrant acquired an interest in the properties at least one year before the date of the service contract through transactions unrelated to the service contract, and that interest is unaffected by the service contract, income from such contract may be recognized subject to the general provisions for elimination of intercompany profit under generally accepted accounting principles.

(C) Not withstanding the provisions of (A) and (B) above, no income may be recognized for contractual services performed on behalf of investors in oil and gas producing activities managed by the registrant or an affiliate. Furthermore, no income may be recognized for contractual services to the extent that the consideration received for such services represents an interest in the underlying property.

(D) Any income not recognized as a result of these rules would be credited to the full cost account and recognized through a lower amortization provision as reserves are produced.

(7) *Disclosures.* Reporting entities that follow the full cost method of accounting shall disclose all of the information required by paragraph (k) of this section, with each cost center considered as a separate geographic area, except that reasonable groupings may be made of cost centers that are not significant in the aggregate[4]. In addition:

(i) For each cost center for each year that an income statement is required, disclose the total amount of amortization expense (per equivalent physical unit of production if amortization is computed on the basis of physical units or per dollar of gross revenue from production if amortization is computed on the basis of gross revenue).

(ii) State separately on the face of the balance sheet the aggregate of the capitalized costs of unproved properties and major development projects that are excluded, in accordance with paragraph (i)(3) of this section, from the capitalized costs being amortized. Provide a description in the notes to the financial statements of the current status of the significant properties or projects involved, including the anticipated timing of the inclusion of the costs in the amortization computation.

[4]This statement refers to deleted Reg. S-X Rule 4-10 paragraph (k). Paragraph (k) disclosures were replaced by SFAS No. 69 disclosure requirements.

Present a table that shows, by category of costs, (A) the total costs excluded as of the most recent fiscal year; and (B) the amounts of such excluded costs, incurred (1) in each of the three most recent fiscal years and (2) in the aggregate for any earlier fiscal years in which the costs were incurred. Categories of cost to be disclosed include acquisition costs, exploration costs, development costs in the case of significant development projects and capitalized interest.

Income Taxes

(d) *Income taxes.* Comprehensive interperiod income tax allocation by a method which complies with generally accepted accounting principles shall be followed for intangible drilling and development costs and other costs incurred that enter into the determination of taxable income and pretax accounting income in different periods.

REGULATION S-K EXCERPT REGARDING FAS 69:

§229.302

(b) *Information about oil and gas producing activities.* Registrants engaged in oil and gas producing activities shall present the information about oil and gas producing activities (as those activities are defined in Regulation S-X, § 210.4-10(a)) specified in paragraphs 9-34 of Statement of Financial Accounting Standards ("SFAS") No. 69, "Disclosures about Oil and Gas Producing Activities," if such oil and gas producing activities are regarded as significant under one or more of the tests set forth in paragraph 8 of SFAS No. 69 [For an additional test, see the excerpt below from FRR Codification §406.02 d.i.].

Instructions to Paragraph (b).

1. (a) SFAS No. 69 disclosures that relate to annual periods shall be presented for each annual period for which an income statement is required, (b) SFAS No. 69 disclosures required as of the end of annual period shall be presented as of the date of each audited balance sheet required, and (c) SFAS No. 69 disclosures required as of the beginning of an annual period shall be presented as of the beginning of each annual period for which an income statement is required.

2. This paragraph, together with §210.4-10 of Regulation S-X, prescribes financial reporting standards for the preparation of accounts by persons engaged, in whole or in part, in the production of crude oil or natural gas in the United States, pursuant to Section 503 of the Energy Policy and Conservation Act of 1975 (42 U.S.C. 6383) ("EPCA") and Section 11(c) of the Energy Supply and Environmental Coordination Act of 1974 (15 U.S.C. 796) ("ESECA") as amended by Section 506 of EPCA. The application of this paragraph to those oil and gas producing operations of companies regulated for ratemaking purposes on an individual-company-cost-of-service basis may, however, give appropriate recognition to differences arising because of the effect of the ratemaking process.

3. Any person exempted by the Department of Energy from any recordkeeping or reporting requirements pursuant to Section 11(c) of ESECA, as amended, is similarly exempted from the related provisions of this paragraph in the preparation of accounts pursuant to EPCA. This exemption does not affect the applicability of this paragraph to filings pursuant to the federal securities laws.

EXCERPTS FROM THE SEC'S CODIFICATION OF FINANCIAL REPORTING RELEASES:

406. Oil and Gas Producing Activities
406.01.c. Full Cost Method
406.01.c.i. Exclusion of Capitalized Costs

. . . Since unevaluated properties are required to be assessed periodically for impairment and to have value at least equal to their carrying costs (including any capitalized interest), exclusion from immediate amortization should not distort future income statements by postponing the recognition of non-productive costs. . . .

With respect to the assessment of impairment generally, the Commission also sees merit in the suggestion that an aggregate assessment of impairment be permitted on individually *in*significant properties, and the final rules have been revised to permit, but not require, that approach. The rules do not include any specific guidance on the determination of "significance." However, the Commission believes that in general individual properties or projects would be expected to be individually significant if their costs exceed 10% of the net capitalized costs of the cost center. Where individual properties or projects with costs representing less than 10% of the cost center are involved, the Commission believes it is still appropriate to test impairment on an individual basis but will permit companies to aggregate such properties for purposes of this assessment . . .

While the final rules permit the general exclusion of all unevaluated costs from immediate amortization, the Commission emphasizes that as soon as it can be determined whether or not proved reserves can be assigned, the related costs should be included in the amortization base. Once these costs are included in the amortization base, they lose their identity for all future accounting purposes. Consequently, individual cost elements cannot subsequently be removed from this base. . . .

406.01.c.iii. Limitation on Capitalized Costs

. . . If application of the rules, as a result of an unusual event or transaction such as major purchase of proved properties, would require a writedown when the fair value of the properties in a cost center clearly exceeds the unamortized costs, the registrant may request an exemption from the general rule. In such cases, the registrant should be prepared to demonstrate that the additional value clearly exists beyond reasonable doubt.

The rules specify that the cost center ceiling is to be computed giving consideration to income tax effects. The Commission believes that unusual tax relationships may exist in certain instances, as a result of the expiration of operating loss carryforwards, change in tax rates, etc. In these circumstances, it will be necessary to consider tax effects in computing the ceiling limitation.

406.01.c.v. Consolidated Financial Statements

The rules specify that a registrant must apply its accounting method to the operations of its subsidiaries. Rule 4-10(c)(3)(v) requires that amortization rates be determined on a consolidated basis even though this may result in a consolidated amortization provision that is not equal to the sum of the expenses for the individual members of the consolidated group. This same concept applies to the determination of the limitation on capitalized costs within cost centers.

406.01.d. Accounting Changes

. . . The Commission expects registrants to comply with GAAP in making an accounting change to or from successful efforts or full costs. Since GAAP expresses a preference for successful efforts, no justification for the change to successful efforts is necessary nor is a preferability letter required by Rule 10-01(b)(6) of Regulation S-X. However, in view of SFAS 25, any change to full cost must be justified as being preferable in the registrant's circumstances and a preferability letter describing those circumstances must be filed with the Commission.

. . . [E]stimates of quantities of oil and gas reserves that had been made in prior years shall not currently be revised in retrospect.

For reporting entities following the full cost method of accounting, retroactive application of Rule 4-10(c)(4), "Limitations on capitalized costs," shall be applied as follows:

(a) If unamortized costs capitalized within a cost center do not exceed the cost center ceiling as of the beginning of the fiscal period in which the rules are initially adopted, then no provisions shall be made for past periods when application of the rules based on information known during those periods might have resulted in unamortized capitalized costs being in excess of the cost center ceiling.

(b) If unamortized costs capitalized within a cost center exceed the cost center ceiling as of the beginning of the fiscal year in which the rules are initially adopted, then this excess shall be recognized retroactively through a charge to expense in the periods in which the excess initially arose.

406.02. Supplemental Disclosures

406.02.b Summary of Operations on the Basis of Reserve Recognition Accounting

By conforming its disclosure requirements with those of the FASB standard, the Commission is eliminating its requirement for a supplemental presentation of an earnings summary based on Reserve Recognition Accounting ("RRA").

406.02.c. Separate Disclosure of Undiscounted Future Net Revenues

. . . [T]he Commission will no longer require separate disclosure of the first three years of future net revenues on an undiscounted basis.

. . . The Commission continues to believe that this sort of information may in some circumstances be essential to an understanding of a company's financial position and results of operations. Accordingly, the Commission reminds registrants that disclosures of undiscounted future cash flows from oil and gas operations may be necessary in the Management's Discussion and Analysis of the financial statements. Such disclosures would ordinarily be expected where near-term cash flows are likely to be negative or only at a break-even level, and may be appropriate in other circumstances.

406.02.d.i. Significance Criteria

The Commission believes that in most instances the significance criteria of SFAS 69 will identify the same enterprises as the Commission's proposed tests.[5] Accordingly, in view of its commitment to conform its rules wherever practicable with those of the private sector, the Commission is not adopting its separate proposed significance tests. However, in those circumstances where the discounted present value of a registrant's oil and gas reserves is significantly in excess of ten percent of consolidated total assets, the Commission expects that the general requirement for disclosure of material amounts will require that some disclosures be made, even if the stated SFAS 14 tests are not met.

406.02.d.ii Applicability of Commission Requirements

The final rules also specify that the subject supplemental disclosures shall be presented whenever required by the terms of the applicable

[5]Author's note: Such criteria are quite similar to the three FAS 131 tests for significant industry segments.

Federal securities form. The SFAS 69 requirements apply to enterprises which are "publicly traded" as defined by the standard. This FASB definition is both broader and narrower than the class of enterprises currently required to provide supplemental oil and gas disclosures in Commission filings. The FASB definition includes certain small enterprises which although "traded" may not be required to file reports under either the Securities Act or the Securities Exchange Act. However, the FASB definition would not apply to other enterprises filing reports with the Commission such as certain limited partnerships, nor would it apply to companies providing information to investors under the Regulation D exemptions. The Commission recognizes that it has a different constituency and must retain the specific requirements of its various filing forms.

406.02.d.iii. Limited Partnerships

Topic 12-A-3-C of the Staff Accounting Bulletin series currently states that in certain circumstances the staff will not take exception to omission of the value based RRA disclosures required by Regulation S-X for limited partnerships engaged in oil and gas producing activities. This waiver applies only to value-based disclosures in periodic reports filed on Form 10-K where (1) the partnership agreement contains a buyout provision under which the general partner agrees to purchase the limited partnership interests that are offered for sale, based upon a specified valuation formula, and (2) some form of reserve value information is available to the limited partners pursuant to the partnership agreement. The staff anticipates that this policy will continue to apply to the comparable "standardized measure" disclosures specified in paragraphs 30-34 of SFAS 69. It should be noted, however, that the waiver in the Staff Accounting Bulletin extends only to value-based disclosures and not to reserve quantity disclosures or historical cost based information. In addition, the waiver was not intended to apply to limited partnerships where owners and buyers do not have some sort of value-based information otherwise automatically provided.

APPENDIX 2: SEC STAFF ACCOUNTING BULLETINS, TOPIC 12
(as of January 1, 2000)

SEC Staff Accounting Bulletins are published accounting interpretations of the SEC Staff. Topic 12 addresses interpretations of S-X Rule 4-10. Subtopics are listed below for easier reference. Topic No. 2's part D addresses financial statements of oil and gas exchange offers but is not included herein; a portion is included in Chapter Twenty-Four.

App. Page	**Subtopic**	
2-2	A	**Accounting Series Release No. 257**
2-2	A1	Proved reserves
2-3	A2	Future revenues
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2-10	A4	Filings by Canadian Registrants
2-10	B	**Accounting Series Release No. 269**
		Subtopic B is no longer applicable and is omitted from Appendix 2.
2-10	C	**Methods of Accounting by Oil and Gas Producers**
2-10	C1	First-time registrants
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2-12	D1	Treatment of income tax effects in the computation of the limitation on capitalized costs
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2-14	D3	Full cost ceiling limitation
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2-18	F	**Gross Revenue Method of Amortizing Capitalized Costs**
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TOPIC 12: OIL AND GAS PRODUCING ACTIVITIES

[Note: The statements in Staff Accounting Bulletins are not rules or interpretations of the Securities and Exchange Commission nor are they published as bearing the SEC's official approval. They represent interpretations and practices followed by the SEC's Division of Corporation Finance and the Office of the Chief Accountant in administering the disclosure requirements of the Federal securities laws.]

A. ACCOUNTING SERIES RELEASE NO. 257 — Requirements for Financial Accounting and Reporting Practices for Oil and Gas Producing Activities

1. Estimates of Quantities of Proved Reserves

Facts: Rule 4-10 contains definitions of proved reserves, proved developed reserves, and proved undeveloped reserves to be used in determining quantities of oil and gas reserves to be reported in filings with the Commission.

Question 1: The definition of proved reserves states that reservoirs are considered proved if "economic producibility is supported by either actual production or conclusive formation test." May oil and gas reserves be considered proved if economic producibility is supported only by core analyses and/or electric or other log interpretations?

Interpretive Response: Economic producibility of estimated proved reserves can be supported to the satisfaction of the Office of Engineering if geological and engineering data demonstrate with reasonable certainty that those reserves can be recovered in future years under existing economic and operating conditions. The relative importance of the many pieces of geological and engineering data which should be evaluated when classifying reserves cannot be identified in advance. In certain instances, proved reserves may be assigned to reservoirs on the basis of a combination of electrical and other type logs and core analyses which indicate the reservoirs are analogous to similar reservoirs in the same field which are producing or have demonstrated the ability to produce on a formation test.

Question 2: In determining whether "proved undeveloped reserves" encompass acreage on which fluid injection (or other improved recovery technique) is contemplated, is it appropriate to distinguish between (i) fluid injection used for pressure maintenance during the early life of a field and (ii) fluid injection used to effect secondary recovery when a field is in the late stages of depletion? The definition in Rule 4-10(a)(4) does not make this distinction between pressure maintenance activity and fluid injection undertaken for purposes of secondary recovery.

Interpretive Response: The Office of Engineering believes that the distinction identified in the above question may be appropriate in a few limited circumstances, such as in the case of certain fields in the North Sea. The staff will review estimates of proved reserves attributable to fluid injection in the light of the strength of the evidence presented by the registrant in support of a contention that enhanced recovery will be achieved.

Question 3: What volumes of natural gas liquids should be reported as net reserves, that portion recovered in a gas processing plant and allocated to the leasehold interest or the total recovered by a plant from net interest gas?

Interpretive Response: Companies should report reserves of natural gas liquids which are net to their leasehold interests, i.e., that portion recovered in a processing plant and allocated to the leasehold interest. It may be appropriate in the case of natural gas liquids not clearly attributable to leasehold interests ownership to follow instruction (b) of Item 2(b)(3) of Regulation S-K [redesignated as Securities Act Industry Guide 2, Item 3] and report such reserves separately and describe the nature of the ownership.

Question 4: What pressure base should be used for reporting gas and production, 14.73 psia or the pressure base specified by the state?

Interpretive Response: The reporting instructions to the Department of Energy's Form EIA-28 specify that natural gas reserves are to be reported at 14.73 psia and 60 degrees F. There is no pressure base specified in Regulation S-X or S-K. At the present time the staff will not object to natural gas reserves and production data calculated at other pressure bases, if such other pressure bases are identified in the filing.

2. Estimates of Future Revenues

Facts: Paragraph (k)(6) of Rule 4-10 requires the disclosure of the estimated future net reserves from production of proved oil and gas reserves, computed by applying current prices of oil and gas (with consideration of price changes only to the extent provided by contractual arrangements) to estimated future production as of the latest balance sheet date, less estimated future expenditures (based on current costs) of developing and producing the proved reserves, and assuming continuation of existing economic conditions.

Question 1: For purposes of determining reserves and estimated future net revenues, what price should be used for gas which will be produced after an existing contract expires or after the redetermination date in a contract?

Interpretive Response: The price to be used for gas which will be produced after a contract expires or has a redetermination is the current market price at the end of the fiscal year for that category of gas plus any fixed and determinable price escalations applicable to that category of gas under the Natural Gas Policy Act of 1978 (NGPA) through the date of expiration or redetermination. This price may be increased thereafter only for additional fixed and determinable escalations, as appropriate, for that category of gas. A fixed and determinable escalation is one which is specified in amount and is not based on future events such as rates of inflation.

Question 2: What price should be applied to gas which at the end of a fiscal year is not yet subject to a gas sales contract?

Interpretive Response: The price to be used is the current market price for similarly situated gas at the end of the fiscal year plus, for estimated future production, fixed and determinable escalations to be allowed by the NGPA, provided the company can reasonably expect to sell the gas at the prevailing market price.

Question 3: What price should be used for gas which will be produced in the future after a well is contemplated to become a "stripper" well?

Interpretive Response: At the time in the future when it is contemplated that a gas well will qualify for stripper classification, the current price for stripper gas (adjusted for fixed and determinable escalations to the date that stripper status is attained) may be used. This assumes that the gas is not subject to a contract at a lower price.

Question 4: In connection with the pricing of oil, what price should be used for oil which will be produced after a well becomes a stripper well?

Interpretive Response: Oil that is estimated to be produced after a well qualifies as a stripper should be valued using the current price for stripper oil in effect at the end of the fiscal year.

Question 5: The NGPA appears to retain certain pricing provisions of the 1938 Natural Gas Act for natural gas dedicated to interstate commerce prior to the enactment of the 1978 Act (November 9, 1978). If natural gas dedicated to interstate commerce prior to November 9, 1978, is subject to a gas purchase contract that expressly incorporates the price escalation provisions of the Federal Power Commission Opinion No. 770-A under the 1938 Act, may a determination of the price of such gas take into account these escalation provisions even though Rule 4-10(a)(2) of Regulation S-X prohibits adjustment for inflation?

Interpretive Response: The rules specify the use of current prices plus future fixed and determinable escalations. If the company determines that FPC Opinion No. 770-A prices are to be received and the escalation provisions of that Opinion are incorporated in the gas purchase contract, those specified escalations are considered fixed and determinable. If NGPA prices are to be received, only those escalations not based on inflation can be considered.

Question 6: Under what condition can appropriate NGPA prices and escalations be used for contracts which have area rate escalations and are now being amended to specify NGPA prices?

Interpretive Response: The response to this question is similar to the preceding response. If the NGPA price will be received under the present contract, escalations that are fixed and determinable may be considered.

Question 7: Since April 1979, as directed by the President, the Department of Energy has issued a series of regulations designed to phase out price controls on domestic crude oil by October 1, 1981. Lower tier oil was moved to upper tier prices at the rate of 1.5 percent per month starting June 1, 1979, and lower tier oil has been moving to upper tier prices at the rate of 3 percent per month starting January 1, 1980. Beginning January 1, 1980, producers were permitted to sell each month an additional 4.6% of their upper tier oil at the uncontrolled market price. A "windfall profits" tax on the increased selling price of controlled oil attributed to this phased decontrol has also been enacted. To what extent should these pricing changes and taxes be taken into consideration in estimating future net revenues?

Interpretive Response: Registrants should give full effect to price increases associated with phased decontrol. Future monthly reclassifications of oil from lower to upper tier and from upper tier to uncontrolled market price should generally be priced at the prices being received for the applicable categories at the date of the reserve valuation. In addition, the "windfall profits" tax should be considered in computing future net revenues.

Question 8: To what extent should price increases announced by OPEC or by certain government agencies not yet effective at the date of the reserve report be considered in determining current prices?

Interpretive Response: Current prices should not reflect price increases announced but not yet effective at the date of the reserve valuation, i.e., the end of the fiscal year.

Question 9: The Crude Oil Windfall Profit Tax Act of 1980 provides for a phaseout period which is to be a 33-month period beginning no earlier than December 1987 and not later than December 1990, depending on when Government revenues from the windfall profit tax reach $227.3 billion. For what periods should registrants give effect to the windfall profit tax in the computation of future net revenues?

Interpretive Response: Since there is no way to determine the point at which $227.3 billion of windfall profit tax will have been collected, registrants should assume the tax will terminate in 1993 if at the time of the estimate they have no reason to believe that the tax will extend beyond that date.

Question 10: Since an Executive Order by the President allowed the prices of all oil to be decontrolled effective January 28, 1981, should registrants give effect to this accelerated decontrol in their calculations of future net revenues as of December 31, 1980?

Interpretive Response: No. Registrants with calendar year ends should use the oil prices in effect at December 31, 1980; however, if decontrol has a significant effect on the future net revenues for the next succeeding fiscal year, that effect should be disclosed. The effect of the decontrol will appear as a price change in the 1981 Summary of Oil and Gas Producing Activities on the Basis of Reserve Recognition Accounting.

Question 11: Under the Natural Gas Policy Act (NGPA), certain categories of natural gas will be deregulated as of January 1, 1985. In computing estimates of future net revenues pursuant to Rule 4-10(k)(6) of Regulation S-X, what price should be used for estimated gas production after the decontrol date? [Topic 12's footnote 1 not shown herein expresses that interpretive guidance for RRA future net revenues would be applicable to FAS 69 disclosures that supersede disclosures of future net revenues.]

Interpretive Response: Companies should base pricing of production subsequent to the date a particular category of gas is scheduled to be decontrolled on the price applicable to the gas immediately prior to the decontrol date, *i.e.*, at the current sales price at the end of the fiscal year for that category of gas, adjusted only for fixed and determinable escalation (provided in all cases the company can reasonably expect to receive the price used). Such pricing should be used even if the applicable gas sales contracts contain escalation provisions such as area-rate escalator clauses or clauses tied to the prices of competitive fuels.

This practice differs from the circumstances involved with the decontrol of crude oil prices in 1980 and 1981 (see Question 7 in this section), because the market and regulatory conditions affecting natural gas differ substantially from those relating to crude oil during the earlier period. The current decontrolled price of gas may not prevail as a market clearing price under deregulated conditions, and accordingly the staff does not consider it appropriate to apply the current decontrolled price to production subsequent to the decontrol date. Registrants are also reminded that the current instability in the natural gas market may require increased scrutiny of both (1) the expected timing of estimated future production and (2) the appropriate prices to be applied to all future production for purposes of the future net revenue calculation. The estimates of future production should take into account the known or reasonably likely impact of reduced takes by purchasers, pursuant to contractual rights or otherwise. Similarly, as noted in the response to Question 2 in this section, whether the gas in question is eligible for current market prices or is subject to some lower ceiling, the use of the maximum eligible price is appropriate *only* provided the company can reasonably expect to sell the gas at that price.

3. Disclosure of Reserve Information

a. Income Tax Effects

Facts: Income taxes are excluded from the computation of future net revenues and present values required pursuant to paragraph (k)(6) of Rule 4-10.

Question: Is it acceptable to compute the estimated income taxes related to the future net revenues and report net-of-tax present value amounts in addition to the pretax present value amounts?

Interpretive Response: Yes. The staff encourages registrants to present net-of-tax disclosures. The method used to compute the estimated income tax should be adequately explained.

b. Unproved Properties

Facts: Disclosures of reserve information are based on estimated quantities of proved reserves of oil and gas. Regulation S-K prohibits disclosure of estimated quantities of probable or possible reserves of oil and gas and any estimated value thereof in any document publicly filed with the Commission.

Question: What types of disclosures will be permitted by registrants who wish to indicate that some of their properties have value other than that attributable to proved reserves?

Interpretive Response: The Office of Engineering has, for the past several years, suggested to registrants the following form of disclosure for undeveloped lease acreage:

> "In addition to proved reserves, the estimated (or appraised) value of leases or parts of leases to which proved reserves cannot be attributable is $xxx."

The registrant should describe the basis on which the estimate was made. For example, such estimated values are often based on the market demand for leasehold acreage which, in turn, is based on a number of qualitative factors such as proximity to production. If the disclosed amount is based on an appraisal, the person making the appraisal should be named.

c. Limited Partnership 10-K Reports

Facts: Regulation S-K contains an exemption from the requirements of Item 2(b) to disclose certain information relating to oil and gas operations for "limited partnerships or joint ventures that conduct, operate, manage, or report upon oil and gas drilling income programs which acquire properties either for drilling and production, or for production of oil, gas, or geothermal steam." Regulation S-X does not contain a similar exemption from the disclosure requirements of Rule 4-10(k).

Limited partnership agreements often contain buy-out provisions under which the general partner agrees to purchase limited partnership interests that are offered for sale, based upon a specified valuation formula. Because of theses arrangements, the requirements of Regulation S-X for disclosure of reserve value information may be of little significance to the limited partners.

Question: Must the financial statements of limited partnerships included in reports on Form 10-K contain the disclosures of estimated future net revenues, present values and changes therein, and supplemental summary of oil and gas activities specified by paragraphs (k)(6), (k)(7) and (k)(8) of Rule 4-10?

Interpretive Response: The staff will not take exception to the omission of these disclosures in a limited partnership Form 10-K if reserve value information is available to the limited partners pursuant to the partnership agreement (even though the valuations may be computed differently and may be as of a date other than year end). However, the staff will require all of the information specified by paragraph (k) of Rule 4-10 for partnerships which are the subject of a merger or exchange offer under which various limited partnerships are to be combined into a single entity.

d. Limited Partnership Registration Statements

Facts: The staff requires that a registration statement relating to an offering of limited partnership interests include the most recent year-end balance sheet of the general partner. This is considered necessary for purposes of assessing the financial responsibility of the general partner.

Question: What disclosures of oil and gas reserve information must accompany the balance sheet of the general partner?

Interpretive Response: Disclosures should include oil and gas reserve information that pertains to the balance sheet, i.e., the estimated year-end quantities of proved oil and gas reserves and the estimated future net revenues and present values thereof specified by paragraphs (k)(5) and (k)(6) of Rule 4-10.

e. Rate Regulated Companies

Question: If a company has cost-of-service oil and gas producing properties, how should they be treated in the supplemental disclosures of reserve quantities and related future net revenues provided pursuant to Rule 4-10(k) of Regulation S-X?

Interpretive Response: Rule 4-10 provides that registrants may give effect to differences arising from the ratemaking process for cost-of-service oil and gas properties. Accordingly, in these circumstances, the staff believes that the company's supplemental reserve quantity disclosures should indicate separately the quantities associated with properties subject to cost-of-service ratemaking, and that it is appropriate to exclude those quantities from the future net revenue disclosures. The company should also disclose the nature and impact of its cost-of-service ratemaking, including the unamortized cost included in the balance sheet.

4. Filings by Canadian Registrants

Facts: Canadian registrants subject to sections 13 or 15(d) of the Securities Exchange Act generally are required to file annual reports on Form 10-K, and are therefore required to comply with the provisions of Regulation S-X. However, many Canadian oil and gas companies currently follow Canadian generally accepted accounting principles in the presentation of their financial statements, rather than the prescribed form of either successful efforts or full cost contained in Rule 4-10 of Regulation S-X.

Question: May Canadian oil and gas companies continue to follow Canadian generally accepted accounting principles for purposes of reports on Form 10-K? If so, what disclosures are required to be included?

Interpretive Response: A Canadian registrant following a method of accounting other than one of the prescribed methods contained in Rule 4-10 of Regulation S-X may continue to follow such method but should describe the differences in a footnote and include a reconciliation showing the net income that would be reported pursuant to the Commission's rules. In addition, all Canadian registrants should include the disclosures specified by paragraph (k) of Rule 4-10, including oil and gas reserve quantities, estimated future net revenues, present value information, and the supplementary summary of oil and gas producing activities.

B. ACCOUNTING SERIES RELEASE NO. 269 [Omitted in this appendix since it addresses reserve recognition accounting, a method no longer in use.]

C. METHODS OF ACCOUNTING BY OIL AND GAS PRODUCERS

1. First-time Registrants

Facts: In Accounting Series Release No. 300, the Commission announced that it would allow registrants to change methods of accounting for oil and gas producing activities so long as such changes were in accordance with generally accepted accounting principles. Accordingly, the Commission stated that changes from the full cost method to the successful efforts method would not require a preferability letter because of the position expressed in Statement of Financial Accounting Standards No. 25 that successful efforts is considered preferable by the FASB for accounting changes. Changes *to* full cost, however, would require justification by the company making the change and filing of a preferability letter from the company's independent accountants.

Question: How does this policy apply to a non-public company which changes its accounting method in connection with a forthcoming public offering or initial registration under either the 1933 Act or 1934 Act?

Interpretive Response: The Commission's policy that first time registrants may change their previous accounting methods without filing a preferability letter is applicable. Therefore, such a company may change to the full cost method without filing a preferability letter.

2. Consistent Use of Accounting Methods Within a Consolidated Entity

Facts: Rule 4-10(c) of Regulation S-X states that "a reporting entity that follows the full cost method shall apply that method to all of its operations and to the operations of its subsidiaries."

Question 1: If a parent company uses the successful efforts method of accounting for oil and gas producing activities, may a subsidiary of the parent use of the full cost method?

Interpretive Response: No. The use of different methods of accounting in the consolidated financial statements by a parent company and its subsidiary would be inconsistent with the full cost requirement that a parent and its subsidiaries all use the same method of accounting.

The staff's general policy is that an enterprise should account for all its like operations in the same manner. However, Rule 4-10 of Regulation S-X provides that oil and gas companies with cost-of-service oil and gas properties may give effect to any difference resulting from the ratemaking process, including regulatory requirements that a certain accounting method be used for the cost-of-service properties.

Question 2: Must the method of accounting (full cost or successful efforts) followed by a registrant for its oil and gas producing activities also be followed by any fifty percent or less owned companies in which the registrant carries its investment on the equity method (equity investees)?

Interpretive Response: No. Conformity of accounting methods between a registrant and its equity investees, although desirable, may not be practicable and thus is not required. However, if a registrant proportionately consolidates its equity investees, it will be necessary to present them all on the same basis of accounting.

D. APPLICATION OF FULL COST METHOD OF ACCOUNTING

1. Treatment of Income Tax Effects in the Computation of the Limitation on Capitalized Costs

Facts: Item (D) of Rule 4-10(c)(4) of Regulation S-X states that the income tax effects related to the properties involved should be deducted in computing the full cost ceiling.

Question 1: What specific types of income tax effects should be considered in computing the income tax effects to be deducted from estimated future net revenues?

Interpretive Response: The rule refers to income tax effects generally. Thus, the computation should take into account (i) the tax basis of oil and gas properties, (ii) net operating loss carryforwards, (iii) foreign tax credit carryforwards, (iv) investments tax credits, (v) minimum taxes on tax preference items, and (vi) the impact of statutory (percentage) depletion.

It may often be difficult to allocate net operating loss carryforwards (NOL's) between oil and gas assets and other assets. However, to the extent that the NOL's are clearly attributable to oil and gas operations and are expected to be realized within the carryforward period, they should be added to tax basis.

Similarly, to the extent that investment tax credit (ITC) carryforwards and foreign tax credit carryforwards are attributable to oil and gas operations and are expected to be realized within the carryforward period, they should be considered as a deduction from the tax effect otherwise computed. Consideration of NOL's and ITC or foreign tax credit carryforwards should not, of course, reduce the total tax effect below zero.

Question 2: How should the tax effect be computed considering the various factors discussed above?

Interpretive Response: Theoretically, taxable income and tax could be determined on a year-by-year basis and the present value of the related tax computed. However, the "shortcut" method illustrated below is also acceptable.

ASSUMPTIONS:

Capitalized Costs of Oil and Gas Assets		$ 500,000
Accumulated DD&A		(100,000)
Book basis of oil and gas assets		400,000
Related deferred income taxes		(35,000)
Net book basis to be recovered		$ 365,000
NOL carryforward*		$ 20,000
Foreign tax credit carryforward*		$ 1,000
ITC-Carryforward*	$ 2,000	
Present value of ITC relating to future development costs	1,500	$ 3,500
Estimated preference (minimum) tax on percentage depletion in excess of cost depletion		$ 500
Tax basis of oil and gas assets		$ 270,000
Present value of statutory depletion attributable to future deductions		$ 10,000
Statutory tax rate		46%
Present value of future net revenues from proved oil and gas reserves		$ 272,000
Cost of properties not being amortized		$ 55,000
Lower of cost or estimated fair value of unproved properties included in costs being amortized		$ 49,000

* All carryforward amounts in this example represent amounts which are available for tax purposes and which relate to oil and gas operations.

CALCULATION:

Present value of future net revenue		$ 272,000
Cost of properties not being amortized		55,000
Lower of cost or estimated fair value of unproved properties included in costs being amortized		49,000
Tax Effects:		
Total of above items	$ 376,000	
Less: Tax basis of properties	(270,000)	
Statutory depletion	(10,000)	
NOL carryforward	(20,000)	(300,000)
Future taxable inc	76,000	
Tax rate	x 46%	
Tax payable at statutory rate	(34,960)	
ITC	3,500	
Foreign tax credit carryforward	1,000	
Estimated preference tax	(500)	
Total tax effects		(30,960)
Cost Center Ceiling		$ 345,040
Less: Net book basis		365,000
Required write-off, net of tax**		$ (19,960)

** For accounting purposes, the gross write-off should be recorded to adjust both the oil and gas properties account and the related deferred income taxes.

2. Exclusion of Costs from Amortization

Facts: Rule 4-10(c)(3)(ii) indicates that the costs of acquiring and evaluating unproved properties may be excluded from capitalized costs to be amortized it the costs are unusually significant in relation to aggregate costs to be amortized. Costs of major development projects may also be excluded if unusually significant development costs must be incurred prior to ascertaining the quantities of proved reserves attributable to such properties.

Question: At what point should amortization of previously excluded costs commence—when proved reserves have been established or when those reserves become marketable? For instance, a determination of proved reserves may be made before completion of an extraction plant necessary to process sour crude or a pipeline necessary to market the reserves. May the costs continue to be excluded from amortization until the plant or pipeline is in service?

Interpretive Response: No. The proved reserves and the costs allocable to such reserves should be transferred into the amortization base on an ongoing (well-by-well or property-by- property) basis as the project is evaluated and proved reserves are established.

Once the determination of proved reserves has been made, there is no justification for continued exclusion from the full cost pool, regardless of whether other factors prevent immediate marketing. Moreover, at the same time that the costs are transferred into the amortization base, it its also necessary in accordance with FASB Interpretation No. 33 and Statement of Financial Accounting Standards No. 34 to terminate capitalization of interest on such properties.

In this regard, registrants are reminded of their responsi-bilities not to delay recognizing reserves as proved once they have met the engineering standard.

3. Full Cost Ceiling Limitation

a. Exemptions for Purchased Properties

Facts: During 1981, a registrant purchases proved oil and gas reserves in place ("the purchased reserves") in an arm's length transaction for the sum of $9.8 million. Primarily because the registrant expects oil and gas prices to escalate, it paid $1.2 million more for the purchased reserves than the "Present Value of Estimated Future Net Revenues" computed as defined in Rule 4-10(k)(6)(ii) of Regulation S-X. An analysis of the registrant's full cost center in which the purchased reserves are located at December 31, 1981 is as follows:

(Amounts in 1,000)	Total	Purchased Reserves	Other Proved Properties	Unproved Properties
Present value of estimated future net revenues	$14,100	$8,600	$5,500	—
Cost, net of amortization	$16,300	$9,800	$5,500	$1,000
Related deferred taxes	$ 2,300	—	$2,000	$300
Income tax effects related to properties	$ 2,500	—	$2,500	—

Comparison of capitalized costs with limitation on capitalized costs at December 31, 1981:

	Including Purchased Reserves	Excluding Purchased Reserves
Capitalized costs, net of amortization	$16,300	$6,500
Related deferred taxes	(2,300)	(2,300)
Net book cost	14,000	4,200
Present value of estimated future net revenues	14,100	5,500
Lower of cost or market of unproved properties	1,000	1,000
Income tax effects related to properties	(2,500)	(2,500)
Limitation on capitalized costs	12,600	4,000
Excess of capitalized costs over limitation on capitalized costs, net of tax*	$ 1,400	$ 200

* For accounting purposes, the gross write-off should be recorded to adjust both the oil and gas properties account and the related deferred income taxes.

Question: Is it necessary for the registrant to write down the carrying value of its full cost center at December 31, 1981 by $1,400,000?

Interpretive Response: Although the net carrying value of the full cost center exceeds the cost center's limitation on capitalized costs, the text of Accounting Series Release No. 258 provides that a registrant may request an exemption from the rule if as a result of a major purchase of proved properties, a write down would be required even though the registrant believes the fair value of the properties in a cost center clearly exceeds the unamortized costs.

Therefore, to the extent that the excess carrying value relates to the purchased reserves, the registrant may seek a temporary waiver of the full-cost ceiling limitation from the staff of the Commission.

Registrants requesting a waiver should be prepared to demonstrate that the additional value exists beyond reasonable doubt.

To the extent that the excess costs relate to properties *other than* the purchased reserves, however, a write-off should be recorded in the current period. In order to determine the portion of the total excess carrying value which is attributable to properties other than the purchased reserves, it is necessary to perform the ceiling computation on a "with and without" basis as shown in the example above. Thus in this case, the registrant must record a write-down of $200,000 applicable to other reserves. An additional $1,200,000 write-down would be necessary unless a waiver were obtained.

b. Effect of Subsequent Events on the Computation of the Limitation on Capitalized Costs

Facts: Rule 4-10(c)(4)(ii) of Regulation S-X provides that an excess of unamortized capitalized costs within a cost center over the related cost ceiling shall be charged to expense in the period the excess occurs.

Question: Assume that at the date of a company's fiscal year-end, its capitalized costs of oil and gas producing properties exceed the limitation prescribed by Rule 4-10(c)(4) of Regulation S-X. Thus, a write down is indicated. Subsequent to year-end but before the date of the auditors' report on the company's financial statements, assume that one of two events occurs: (1) additional reserves are proved up on properties owned at year-end, or (2) price increases become known which were not fixed and determinable at year-end. The present value of future net revenues from the additional reserves or from the increased prices is sufficiently large that if the full cost ceiling limitation were recomputed giving effect to those factors as of year-end, the ceiling would more than cover the costs. Is it necessary to record a write down?

Interpretive Response: No. In these cases, the proving up of additional reserves on properties owned at year-end or the increase in prices indicates that the capitalized costs were not in fact impaired at year-end. However, for purposes of the revised computation of the "ceiling," the net book costs capitalized as of year-end should be increased by the amount of any additional costs incurred subsequent to year-end to prove the additional reserves or by any related costs previously excluded from amortization.

The registrant's financial statements should disclose that capitalized costs exceeded the limitation thereon at year end and should explain why the excess was not charged against earnings. In addition, the registrant's supplemental disclosures of estimated proved reserve quantities and related future net revenues and costs should *not* give effect to the reserves proved up or costs incurred after year-end or to the price increases occurring after year-end. However, such quantities and amounts may be disclosed separately, with appropriate explanations.

Registrants should be aware that oil and gas reserves related to properties acquired after year-end would *not* justify avoiding a write-off indicated as of year-end. Such acquisitions do not confirm situations existing at year-end.

E. FINANCIAL STATEMENTS OF ROYALTY TRUSTS

Facts: Several oil and gas exploration and production companies have created "royalty trusts." Typically, the creating company conveys a net profits interest in certain of its oil and gas properties to the newly created trust and then distributes units in the trust to its shareholders. The trust is a passive entity which is prohibited from entering into or engaging in any business or commercial activity of any kind and from acquiring any oil and gas lease, royalty or other mineral interest. The function of the trust is to serve as an agent to distribute the income from the net profits interest. The amount to be periodically distributed to the unitholders is defined in the trust agreement and is typically determined based on the cash received from the net profits interest less expenses of the trustee. Royalty trusts have typically reported their earnings on the basis of cash distributions to unitholders. The net profits interest paid to the trust for any month is based on production from a preceding month; therefore, the method of accounting followed by the trust for the net profits interest income is different from the creating company's method of accounting for the related revenue.

Question: Will the staff accept a statement of distributable income which reflects the amounts to be distributed for the period in question under the terms of the trust agreement in lieu of a statement of income prepared under generally accepted accounting principles?

Interpretive Response: Yes. Although financial statements filed with the Commission are normally required to be prepared in accordance with generally accepted accounting principles, the Commission's rules provide that other presentations may be acceptable in unusual situations. Since the operations of a royalty trust are limited to the distribution of income from the net profits interests contributed to it, the staff believes that the item of primary importance to the reader of the financial statements of the royalty trust is the amount of the cash distributions to the unitholders for the period reported. Should there be any change in the nature of the trust's operations due to revisions in the tax laws or other factors, the staff's interpretation would be reexamined.

A note to the financial statements should disclose the method used in determining distributable income and should also describe how distributable income as reported differs from income determined on the basis of generally accepted accounting principles.

F. GROSS REVENUE METHOD OF AMORTIZING CAPITALIZED COSTS

Facts: Rule 4-10(c)(3)(iii) of Regulation S-X states in part:

> "Amortization shall be computed on the basis of physical units, with oil and gas converted to a common unit of measure on the basis of their approximate relative energy content, unless economic circumstances (related to the effects of regulated prices) indicate that use of units of revenue is a more appropriate basis of computing amortization. In the latter case, amortization shall be computed on the basis of current gross revenues (excluding royalty payments and net profits disbursements) from production in relation to future gross revenues based on current prices (including consideration of changes in existing prices provided only by contractual arrangements), from estimated production of proved oil and gas reserves."

Question: May entities using the full cost method of accounting for oil and gas producing activities compute amortization based on the gross revenue method described in the above rule when substantial production is not subject to pricing regulation?

Interpretive Response: Yes. Under the existing rules for cost amortization adopted in Accounting Series Release No. 258, the use of the gross revenue method of amortization was permitted in those circumstances where, because of the effect of existing pricing regulations, the use of the units of production method would result in an amortization provision that would be inconsistent with the current prices being received. While the effect of regulation on gas prices has lessened, factors other than price regulation (such as changes in typical contract lengths and methods of marketing natural gas) have caused oil and gas prices to be disproportionate to their relative energy content. The staff therefore believes that it may be more appropriate for registrants to compute amortization based on the gross revenue method whenever oil and gas sales prices are disproportionate to their relative energy content to the extent that the use of the units of production method would result in an improper matching of the costs of oil and gas production against the related revenue received. The method should be consistently applied and appropriately disclosed within the financial statements.

G. INCLUSION OF METHANE GAS IN PROVED RESERVES

Facts: Because of a concern over worldwide oil and gas supplies, Congress, in 1980, provided for tax incentives (credits) for the production of oil and gas from other than conventional sources. As a consequence, significant amounts of gas have begun to be recovered from seams of coal beds. This gas is referred to as coalbed methane. It is produced using conventional drilling methods, but for various reasons, it may be more costly to produce than oil and gas recovered from customary sources and some reserves may not be economical without the tax credits.

Rule 4-10(a)(1)(i)(A) of Regulation S-X indicates that oil and gas producing activities include the search for crude oil, including condensate and natural gas liquids, or natural gas in their natural states and original locations. Rule 4-10(a)(2)(iii)(D) of Regulation S-X states that estimates of proved reserves do not include (among other things) natural gas that can be recovered from coal. In addition, the definition of proved oil and gas reserves includes a provision that the quantities of natural gas be recovered from existing reservoirs. Under these definitions, "coalbed methane" gas has generally not been included in the disclosures required in Commission filings by Rule 4-10(k) of Regulation S-X. Further, coalbed methane has generally not been counted in proved oil and gas reserves for purposes of the full cost ceiling test in Rule 4-10(c)(4) since that test is based on the same definition of proved oil and gas reserves.

Question: Is it appropriate to consider coalbed methane gas within the definition of proved reserves for purposes of the disclosures relating to oil and gas producing activities and the full cost ceiling test?

Answer: Yes. The prohibition against the inclusion of gas derived from coal was meant to apply to the recovery of hydrocarbons from the processing of coal. The extraction of methane gas from coalbed seams using conventional methods was not contemplated at the time Rule 4-10(a) was developed. The staff believes that, since coalbed methane gas can be recovered from coal in its natural state and original location, it should be included in proved reserves, provided that it complies in all other respects with the definition of proved oil and gas reserves as specified in Rule 4-10(a)(2) including the requirements that methane production be economical at current prices, costs (net of the tax credit) and existing operating conditions. Methane gas from coalbeds (like any other hydrocarbon obtained from conventional reservoirs) that cannot be produced at a profit under current economic and operating conditions, or for which there is no market or any existing method of delivery to the market, cannot be included in the category of proved reserves.

In instances where methane gas is deemed to be economically producible only as a consequence of existing Federal tax incentives, the staff believes that additional disclosure should be provided as to the specific quantities and values of reported proved reserves that are dependent on existing U.S. tax policy together with any other information necessary to inform readers of the risks attendant with any future change to existing Federal tax policy.

APPENDIX 3: FASB CURRENT TEXT SECTION OI5, OIL AND GAS PRODUCING ACTIVITIES (as of January 1, 2000)

The FASB *Current Text* is an integration of currently effective accounting and reporting standards promulgated by the AICPA and the FASB. The Oi5 section is drawn from FAS 19, 25, 69, 95, 109, 121, and 131 as well as FASB Interpretation 36. Key section subheadings are listed below for easier reference.

App. Page	Oi5 Paragraphs	
3-3	--	**Oi5 Summary**
3-4	.101	**Scope**
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Oi5 SUMMARY

An enterprise with oil and gas producing activities shall classify production payments payable in cash as debt and shall apply comprehensive income tax allocation like other enterprises. Both publicly traded and other enterprises shall disclose the method of accounting for costs incurred in oil and gas producing activities and the manner of disposing of related capitalized costs.

Publicly traded enterprises with significant oil and gas activities, when presenting a complete set of annual financial statements, are to disclose the following as supplementary information, but not as a part of the financial statements:

a. Proved oil and gas reserve quantities
b. Capitalized costs relating to oil and gas producing activities
c. Costs incurred in oil and gas property acquisition, exploration, and development activities
d. Results of operations for oil and gas producing activities
e. A standardized measure of discounted future net cash flows relating to proved oil and gas reserve quantities.

In addition, this section describes a preferable, but not required, form of the successful efforts method of accounting for oil and gas producing activities. Under that method, costs shall be accounted for as follows:

a. Geological and geophysical costs and costs of carrying and retaining undeveloped properties are charged to expense as incurred.
b. Costs of drilling exploratory wells and exploratory-type stratigraphic test wells that do not find proved reserves are charged to expense when the wells do not find proved reserves.
c. Costs of acquiring properties, costs of drilling development wells and development – type stratigraphic test wells, and costs of drilling

successful exploratory wells and exploratory-type stratigraphic test wells are capitalized.

d. The capitalized costs of wells and related equipment are amortized as the related oil and gas reserves are produced.
e. Costs of unproved properties are assessed periodically, and a loss is recognized if the properties are impaired.

SCOPE

.101 This section [presents] standards of financial accounting and reporting for the **oil and gas producing activities** of a business enterprise. Those activities involve the acquisition of mineral interests in properties, exploration (including prospecting), development, and production of crude oil, including condensate and natural gas liquids, and natural gas (hereinafter collectively referred to as oil and gas producing activities). [FAS 19, ¶1] This section applies only to *oil and gas producing activities;* it does not address financial accounting and reporting issues relating to the transporting, refining, and marketing of oil and gas. Also, this section does not apply to activities relating to the production of other wasting (nonregenerative) natural resources; nor does it apply to the production of geothermal steam or to the extraction of hydrocarbons as a by-product of the production of geothermal steam and associated geothermal resources as defined in the *Geothermal Steam Act of 1970;* nor does it apply to the extraction of hydrocarbons from shale, tar sands, or coal. [FAS 19, ¶6]

.102 [Compliance with the accounting standards contained in paragraphs .103 through .132 and .135 through .139 is not required although those standards have been issued by the FASB and remain in existence] for purposes of applying [FASB Current Text's]Section A06, "Accounting Changes," paragraph .112. [FAS 25, ¶4] [Enterprises registered with the Securities and Exchange Commission (SEC), however, are required to apply either those standards or a form of full cost accounting specified in the SEC's rules. The accounting and reporting standards contained in paragraphs .133, .134, .140 through .142 and .156 are required of all enterprises with oil and gas producing activities. In addition, **publicly traded enterprises** that have significant oil and gas producing activities shall make disclosures described in paragraphs .157 and .160 through .184 as supplementary information.]

.103 An enterprise's oil and gas producing activities involve certain special types of assets. Costs of those assets shall be capitalized when incurred. Those types of assets broadly defined are:

a. *Mineral interests in properties* (hereinafter referred to as properties), that include fee ownership or a lease, concession, or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest. Properties also include royalty interests, production payments payable in oil or gas, and other nonoperating interests in properties operated by others. Properties include those agreements with foreign governments or authorities under which an enterprise participates in the operation of the related properties or otherwise serves as producer of the underlying reserves (refer to paragraph .163); but properties do not include other supply agreements or contracts that represent the right to purchase (as opposed to extract) oil and gas. Properties shall be classified as proved or unproved as follows:
   (1) Unproved properties with no **proved reserves**.
   (2) Proved properties with proved reserves.
b. Wells and related equipment and facilities,[1] the costs of which include those incurred to:
   (1) Drill and equip those **exploratory wells** and **exploratory-type stratigraphic test wells** that have found proved reserves.
   (2) Obtain access to proved reserves and provide facilities for extracting, treating, gathering, and storing the oil and gas, including the drilling and equipping of **developing wells** and **development-type stratigraphic test wells** (whether those wells are successful or unsuccessful) and **service wells**.
c. Support equipment and facilities used in oil and gas producing activities (such as seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps, and division, district, or field offices).
d. Uncompleted wells, equipment, and facilities, the costs of which include those incurred to:
   (1) Drill and equip wells that are not yet completed.
   (2) Acquire or construct equipment and facilities that are not yet completed and installed. [FAS 19, ¶11]

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[1]Often referred to in the oil and gas industry as lease and well equipment even though, technically, the property may have been acquired other than by a lease. [FAS 19, ¶11, fn1]

.104 The costs of an enterprise's wells and related equipment and facilities and the costs of the related proved properties shall be amortized as the related oil and gas reserves are produced. That amortization plus production (lifting) costs becomes part of the cost of oil and gas produced. Unproved properties shall be assessed periodically, and a loss [shall be] recognized if those properties are impaired. [FAS 19, ¶12]
.105 Some costs incurred in an enterprise's oil and gas producing activities do not result in acquisition of an asset and, therefore, shall be charged to expense. Examples include geological and geophysical costs, the costs of carrying and retaining undeveloped properties, and the costs of drilling those exploratory wells and exploratory-type stratigraphic test wells that do not find proved reserves. [FAS 19, ¶13]

ACCOUNTING AT THE TIME COSTS ARE INCURRED

Acquisition of Properties

.106 Costs incurred to purchase, lease, or otherwise acquire a property (whether unproved or proved) shall be capitalized when incurred. They include the costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties. [FAS 19, ¶15]

Exploration

.107 Exploration involves (a) identifying areas that may warrant examination and (b) examining specific areas that are considered to have prospects of containing oil and gas reserves, including drilling exploratory wells and exploratory-type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as prospecting costs) and after acquiring the property. [FAS 19, ¶16]

.108 Principal types of exploration costs, which include depreciation and applicable operating costs of support equipment and facilities (refer to paragraph .117) and other costs of exploration activities, are:

a. Costs of topographical, geological, and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews, and others conducting those studies. Collectively, those are sometimes referred to as geological and geophysical, or G&G, costs.

b. Costs of carrying and retaining undeveloped properties, such as delay rentals, *ad valorem* taxes on the properties, legal costs for title defense, and the maintenance of land and lease records.
c. Dry hole contributions and bottom hole contributions.
d. Costs of drilling and equipping exploratory wells.
e. Costs of drilling exploratory-type stratigraphic test wells.[2] [FAS 19, ¶17]

.109 Geological and geophysical costs, costs of carrying and retaining undeveloped properties, and dry hole and bottom hole contributions shall be charged to expense when incurred. [FAS 19, ¶18]

.110 The costs of drilling exploratory wells and the costs of drilling exploratory-type stratigraphic test wells shall be capitalized as part of the enterprise's uncompleted wells, equipment, and facilities pending determination of whether the well has found proved reserves. If the well has found proved reserves (refer to paragraphs. 122 through .125), the capitalized costs of drilling the well shall become part of the enterprise's wells and related equipment and facilities (even though the well may not be completed as a producing well); if, however, the well has not found proved reserves, the capitalized costs of drilling the well, net of any salvage value, shall be charged to expense. [FAS 19, ¶18]

.111 An enterprise sometimes conducts G&G studies and other exploration activities on property owned by another party, in exchange for which the enterprise is contractually entitled to receive an interest in the property if proved reserves are found or to be reimbursed by the owner for the G&G and other costs incurred if proved reserves are not found. In that case, the enterprise conducting the G&G studies and other exploration activities shall account for those costs as a receivable when incurred and, if proved reserves are found, they shall become the cost of the proved property acquired. [FAS 19, ¶20]

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[2][Although] the costs of drilling stratigraphic test wells are sometimes considered to be geological and geophysical costs, they are accounted for separately in this section. [FAS 19, ¶17, fn2]

Development

.112 Development costs are incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering, and storing the oil and gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities (refer to paragraph .117) and other costs of development activities, are costs incurred to:

a. Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines, and power lines, to the extent necessary in developing the proved reserves.
b. Drill and equip development wells, development-type stratigraphic test wells, and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly.
c. Acquire, construct, and install production facilities such as lease flow lines, separators, treaters, heaters, manifolds, measuring devices, and production storage tanks, natural gas cycling and processing plants, and utility and waste disposal systems.
d. Provide improved recovery systems. [FAS 19, ¶21]

.113 Development costs shall be capitalized as part of the cost of an enterprise's wells and related equipment and facilities. Thus, all costs incurred to drill and equip development wells, development-type stratigraphic test wells, and service wells are development costs and shall be capitalized, whether the well is successful or unsuccessful. Costs of drilling those wells and costs of constructing equipment and facilities shall be included in the enterprise's uncompleted wells, equipment, and facilities until drilling or construction is completed. [FAS 19, ¶22]

Production

.114 Production involves lifting the oil and gas to the surface and gathering, treating, **field** processing (as in the case of processing gas to extract liquid hydrocarbons), and field storage. For purposes of this section, the production function shall normally be regarded as terminating at the outlet valve on the lease or field production storage tank; if unusual physical or operational circumstances exist, it may be more appropriate to regard the production function as terminating at the first point at which oil, gas, or gas liquids are delivered to a main pipeline, a common carrier, a refinery, or a marine terminal. [FAS 19, ¶23]

.115 Production costs are those costs incurred to operate and maintain an enterprise's wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities (refer to paragraph .117) and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil and gas produced. Examples of production costs (sometimes called lifting costs) are:

a. Costs of labor to operate the wells and related equipment and facilities
b. Repairs and maintenance
c. Materials, supplies, and fuel consumed and services utilized in operating the wells and related equipment and facilities
d. Property taxes and insurance applicable to proved properties and wells and related equipment and facilities
e. Severance taxes [FAS 19, ¶24]

.116 Depreciation, depletion, and amortization of capitalized acquisition, exploration, and development costs also become part of the cost of oil and gas produced along with production (lifting) costs identified in paragraph .115. [FAS 19, ¶25]

Support Equipment and Facilities

.117 The cost of acquiring or constructing support equipment and facilities used in oil and gas producing activities shall be capitalized. Examples of support equipment and facilities include seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps, and division, district, or field offices. Some support equipment or facilities are acquired or constructed for use exclusively in a single activity--exploration, development, or production. Other support equipment or facilities may serve two or more of those activities and may also serve the enterprise's transportation, refining, and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become an exploration, development, or production cost, as appropriate. [FAS 19, ¶26]

DISPOSITION OF CAPITALIZED COSTS

.118 The effect of paragraphs .106 through .117, which deal with accounting at the time costs are incurred, is to recognize as assets: (a) unproved properties; (b) proved properties; (c) wells and related equipment and facilities (that consist of all development costs plus the costs of drilling those exploratory wells and exploratory-type stratigraphic test wells that find proved reserves); (d) support equipment and facilities used in oil and gas producing activities; and (e) uncompleted wells, equipment, and facilities. Paragraphs .119 through .132 deal with disposition of the costs of those assets after capitalization. Among other things, those paragraphs provide that the acquisition costs of proved properties and the costs of wells and related equipment and facilities be amortized to become part of the cost of oil and gas produced: that impairment of unproved properties be recognized; and that the costs of an exploratory well or exploratory-type stratigraphic test well be charged to expense if the well is determined not to have found proved reserves. [FAS 19, ¶27]

Assessment of Unproved Properties

.119 Unproved properties shall be assessed periodically to determine whether they have been impaired. A property would likely be impaired, for example, if a dry hole has been drilled on it and the enterprise has no firm plans to continue drilling. Also, the likelihood of partial or total impairment of a property increases as the expiration of the lease term approaches if drilling activity has not commenced on the property or on nearby properties. If the results of the assessment indicate impairment, a loss shall be recognized by providing a valuation allowance. Impairment of individual unproved properties whose acquisition costs are relatively significant shall be assessed on a property-by-property basis, and an indicated loss shall be recognized by providing a valuation allowance. When an enterprise has a relatively large number of unproved properties whose acquisition costs are not individually significant, it may not be practical to assess impairment on a property-by-property basis, in which case the amount of loss to be recognized and the amount of the valuation allowance needed to provide for impairment of those properties shall be determined by amortizing those properties, either in the aggregate or by groups, on the basis of the experience of the enterprise in similar situations and other information about such factors as the primary lease terms of those properties, the average holding period of unproved properties, and the relative proportion of such properties on which proved reserves have been found in the past. [FAS 19, ¶28]

Reclassification of an Unproved Property

.120 A property shall be reclassified from unproved properties to proved properties when proved reserves are discovered on or otherwise attributed to the property; occasionally, a single property, such as a foreign lease or concession, covers so vast an area that only the portion of the property to which the proved reserves relate--determined on the basis of geological structural features or stratigraphic conditions--should be reclassified from unproved to proved. For a property whose impairment has been assessed individually in accordance with paragraph .119, the net carrying amount (acquisition cost minus valuation allowance) shall be reclassified to proved properties; for properties amortized by providing a valuation allowance on a group basis, the gross acquisition cost shall be reclassified. [FAS 19, ¶29]

Amortization (Depletion) of Acquisition Costs of Proved Properties

.121 Capitalized acquisition costs of proved properties shall be amortized (depleted) by the unit-of-production method so that each unit produced is assigned a pro rata portion of the unamortized acquisition costs. Under the unit-of-production method, amortization (depletion) may be computed either on a property-by-property basis or on the basis of some reasonable aggregation of properties with a common geological structural feature or stratigraphic condition, such as a **reservoir** or field. If an enterprise has a relatively large number of royalty interests whose acquisition costs are not individually significant, they may be aggregated, for the purpose of computing amortization, without regard to commonality of geological structural features or stratigraphic conditions; if information is not available to estimate reserve quantities applicable to royalty interests owned (refer to paragraph .160), a method other than the unit-of-production method may be used to amortize their acquisition costs. The unit cost shall be computed on the basis of the total estimated units of **proved oil and gas reserves.** (Joint production of both oil and gas is discussed in paragraph .129.) Unit-of-production amortization rates shall be revised whenever there is an indication of the need for revision but at least once a year; those revisions shall be accounted for prospectively as changes in accounting estimates--refer to Section A06, paragraphs .130 through .132. [FAS 19, ¶30]

Accounting When Drilling of an Exploratory Well Is Completed

.122 As specified in paragraph .110, the costs of drilling an exploratory well are capitalized as part of the enterprise's uncompleted wells, equipment, and facilities pending determination of whether the well has found proved reserves. That determination is usually made on or shortly after completion of drilling the well, and the capitalized costs shall either be charged to expense or be reclassified as part of the costs of the enterprise's wells and related equipment and facilities at that time. Occasionally, however, an exploratory well may be determined to have found oil and gas reserves, but classification of those reserves as proved cannot be made when drilling is completed. In those cases, one or the other of the following subparagraphs shall apply depending on whether the well is drilled in an area requiring a major capital expenditure, such as a trunk pipeline, before production from that well could begin:

a. Exploratory wells that find oil and gas reserves in an area requiring a major capital expenditure, such as a trunk pipeline, before production could begin. On completion of drilling, an exploratory well may be determined to have found oil and gas reserves, but classification of those reserves as proved depends on whether a major capital expenditure can be justified which, in turn, depends on whether additional exploratory wells find a sufficient quantity of additional reserves. That situation arises principally with exploratory wells drilled in a remote area for which production would require constructing a trunk pipeline. In that case, the cost of drilling the exploratory well shall continue to be carried as an asset pending determination of whether proved reserves have been found only as long as both of the following conditions are met:
   (1) The well has found a sufficient quantity of reserves to justify its completion as a producing well if the required capital expenditure is made.
   (2) Drilling of the additional exploratory wells is under way or firmly planned for the near future.

Thus, if drilling in the area is not under way or firmly planned, or if the well has not found a commercially producible quantity of reserves, the exploratory well shall be assumed to be impaired, and its costs shall be charged to expense.

b. All other exploratory wells that find oil and gas reserves. In the absence of a determination as to whether the reserves that have been found can be classified as proved, the costs of drilling such an exploratory well shall not be carried as an asset for more than one year following completion of drilling. If, after that year has passed, a determination that proved reserves have been found cannot be made, the well shall be assumed to be impaired, and its costs shall be charged to expense. [FAS 19, ¶31]

.123 Paragraph .122 is intended to prohibit, in all cases, the deferral of the costs of exploratory wells that find some oil and gas reserves merely on the chance that some event totally beyond the control of the enterprise will occur, for example, on the chance that the selling prices of oil and gas will increase sufficiently to result in classification of reserves as proved that are not commercially recoverable at current prices. [FAS 19, ¶32]

Accounting When Drilling of an Exploratory-Type Stratigraphic Test Well Is Completed

.124 As specified in paragraph .110, the costs of drilling an exploratory-type stratigraphic test well are capitalized as part of the enterprise's uncompleted wells, equipment, and facilities pending determination of whether the well has found proved reserves. When that determination is made, the capitalized costs shall be charged to expense if proved reserves are not found or shall be reclassified as part of the costs of the enterprise's wells and related equipment and facilities if proved reserves are found. [FAS 19, ¶33]

.125 Exploratory-type stratigraphic test wells are normally drilled on unproved offshore properties. Frequently, on completion of drilling, such a well may be determined to have found oil and gas reserves, but classification of those reserves as proved depends on whether a major capital expenditure--usually a production platform--can be justified which, in turn, depends on whether additional exploratory-type stratigraphic test wells find a sufficient quantity of additional reserves. In that case, the cost of drilling the exploratory-type stratigraphic test well shall continue to be carried as an asset pending determination of whether proved reserves have been found only as long as both of the following conditions are met:

a. The well has found a quantity of reserves that would justify its completion for production had it not been simply a stratigraphic test well.
b. Drilling of the additional exploratory-type stratigraphic test wells is under way or firmly planned for the near future.

Thus, if associated stratigraphic test drilling is not under way or firmly planned, or if the well has not found a commercially producible quantity of reserves, the exploratory-type stratigraphic test well shall be assumed to be impaired, and its costs shall be charged to expense. [FAS 19, ¶34]

Amortization and Depreciation of Capitalized Exploratory Drilling and Development Costs

.126 Capitalized costs of exploratory wells and exploratory-type stratigraphic test wells that have found proved reserves and capitalized development costs shall be amortized (depreciated) by the unit-of-production method so that each unit produced is assigned a pro rata portion of the unamortized costs. It may be more appropriate, in some cases, to depreciate natural gas cycling and processing plants by a method other than the unit-of-production method. Under the unit-of-production method, amortization (depreciation) may be computed either on a property-by-property basis or on the basis of some reasonable aggregation of properties with a common geological structural feature or stratigraphic condition, such as a reservoir or field. The unit cost shall be computed on the basis of the total estimated units of **proved developed reserves,** rather than on the basis of all proved reserves, which is the basis for amortizing acquisition costs of proved properties. If significant development costs (such as the cost of an offshore production platform) are incurred in connection with a planned group of development wells before all of the planned wells have been drilled, it will be necessary to exclude a portion of those development costs in determining the unit-of-production amortization rate until the additional development wells are drilled. Similarly, it will be necessary to exclude, in computing the amortization rate, those proved developed reserves that will be produced only after significant additional development costs are incurred, such as for improved recovery systems. However, in no case should future development costs be anticipated in computing the amortization rate. (Joint production of both oil and gas is discussed in paragraph .129.) Unit-of-production amortization rates shall be revised whenever there is an indication of the need for revision but at least once a year; those revisions shall be accounted for prospectively as changes in accounting estimates (refer to Section A06, paragraphs .130 through .132). [FAS 19, ¶35]

Depreciation of Support Equipment and Facilities

.127 Depreciation of support equipment and facilities used in oil and gas producing activities shall be accounted for as exploration cost, development cost, or production cost, as appropriate (refer to paragraph .117). [FAS 19, ¶36]

Dismantlement Costs and Salvage Values

.128 Estimated dismantlement, restoration, and abandonment costs and estimated residual salvage values shall be taken into account in determining amortization and depreciation rates. [FAS 19, ¶37]

Amortization of Costs Relating to Oil and Gas Reserves Produced Jointly

.129 The unit-of-production method of amortization requires that the total number of units of oil or gas reserves in a property or group of properties be estimated and that the number of units produced in the current period be determined. Many properties contain both oil and gas reserves. In those cases, the oil and gas reserves and the oil and gas produced shall be converted to a common unit of measure on the basis of their approximate relative energy content (without considering their relative sales values). However, if the relative proportion of gas and oil extracted in the current period is expected to continue throughout the remaining productive life of the property, unit-of-production amortization may be computed on the basis of one of the two minerals only; similarly, if either oil or gas clearly dominates both the reserves and the current production (with dominance determined on the basis of relative energy content), unit-of-production amortization may be computed on the basis of the dominant mineral only. [FAS 19, ¶38]

Information Available after the Balance Sheet Date

.130 Information that becomes available after the end of the period covered by the financial statements but before those financial statements are issued shall be taken into account in evaluating conditions that existed at the balance sheet date, for example, in assessing unproved properties (refer to paragraph .119) and in determining whether an exploratory well or exploratory-type stratigraphic test well had found proved reserves (refer to paragraphs .122 through .125). [FAS 19, ¶39] If an exploratory well or exploratory-type stratigraphic test well is in progress at the end of a period and the well is determined not to have found proved reserves before the financial statements for that period are issued, the costs incurred through the end of the period, net of any salvage value, shall be charged to expense for that period. Previously issued financial statements shall not be retroactively restated. [FIN36, ¶2]

Surrender or Abandonment of Properties

.131 When an unproved property is surrendered, abandoned, or otherwise deemed worthless, capitalized acquisition costs relating thereto shall be charged against the related allowance for impairment to the extent an allowance has been provided; if the allowance previously provided is inadequate, a loss shall be recognized. [FAS 19, ¶40]

.132 Normally, no gain or loss shall be recognized if only an individual well or individual item of equipment is abandoned or retired or if only a single lease or other part of a group of proved properties constituting the amortization base is abandoned or retired as long as the remainder of the property or group of properties continues to produce oil or gas. Instead, the asset being abandoned or retired shall be deemed to be fully amortized, and its cost shall be charged to accumulated depreciation, depletion, or amortization. When the last well on an individual property (if that is the amortization base) or group of properties (if amortization is determined on the basis of an aggregation of properties with a common geological structure) ceases to produce and the entire property or property group is abandoned, gain or loss shall be recognized. Occasionally, the partial abandonment or retirement of a proved property or group of proved properties or the abandonment or retirement of wells or related equipment or facilities may result from a catastrophic event or other major abnormality. In those cases, a loss shall be recognized at the time of abandonment or retirement. [FAS 19, ¶41]

Mineral Property Conveyances and Related Transactions

.133 Mineral interests in properties are frequently conveyed to others for a variety of reasons, including the desire to spread risks, to obtain financing, to improve operating efficiency, and to achieve tax benefits. Conveyances of those interests may involve the transfer of all or a part of the rights and responsibilities of operating a property (operating interest). The transferor may or may not retain an interest in the oil and gas produced that is free of the responsibilities and costs of operating the property (a nonoperating interest). A transaction may, on the other hand, involve the transfer of a nonoperating interest to another party and retention of the operating interest. [FAS 19 ¶42]

.134 Certain transactions, sometimes referred to as conveyances, are in substance borrowings repayable in cash or its equivalent and shall be accounted for as borrowings. The following are examples of such transactions:

a. Enterprises seeking supplies of oil or gas sometimes make cash advances to operators to finance exploration in return for the right to purchase oil or gas discovered. Funds advanced for exploration that are repayable by offset against purchases of oil or gas discovered, or in cash if insufficient oil or gas is produced by a specified date, shall be accounted for as a receivable by the lender and as a payable by the operator.
b. Funds advanced to an operator that are repayable in cash out of the proceeds from a specified share of future production of a producing property, until the amount advanced plus interest at a specified or determinable rate is paid in full, shall be accounted for as a borrowing. The advance is a payable for the recipient of the cash and a receivable for the party making the advance: Such transactions, as well as those described in paragraph .138(a), are commonly referred to as production payments. The two types differ in substance, however, as explained in paragraph .138(a). [FAS 19, ¶43]

.135 In the following types of conveyances, gain or loss shall not be recognized at the time of the conveyance:

a. A transfer of assets used in oil and gas producing activities (including both proved and unproved properties) in exchange for other assets also used in oil and gas producing activities

b. A pooling of assets in a joint undertaking intended to find, develop, or produce oil or gas from a particular property or group of properties [FAS 19, ¶44]

.136 In the following types of conveyances, gain shall not be recognized at the time of the conveyance:

a. A part of an interest owned is sold and substantial uncertainty exists about recovery of the costs applicable to the retained interest.
b. A part of an interest owned is sold and the seller has a substantial obligation for future performance, such as an obligation to drill a well or to operate the property without proportional reimbursement for that portion of the drilling or operating costs applicable to the interest sold. [FAS 19, ¶45]

.137 If a conveyance is not one of the types described in paragraphs .135 and .136, gain or loss shall be recognized unless there are other aspects of the transaction that would prohibit such recognition under accounting principles applicable to enterprises in general. [FAS 19, ¶46]

.138 In accordance with paragraphs .135 through .137, the following types of transactions shall be accounted for as indicated in each example.[3] No attempt has been made to include the many variations of those arrangements that occur, but paragraphs .135 through .137 shall, where applicable, determine the accounting for those other arrangements as well.

a. Some production payments differ from those described in paragraph .134(b) in that the seller's obligation is not expressed in monetary terms but as an obligation to deliver, free and clear of all expenses associated with operation of the property, a specified quantity of oil or gas to the purchaser out of a specified share of future production. Such a transaction is a sale of a mineral interest for which gain shall not be recognized because the seller has a substantial obligation for

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[3]Costs of unproved properties are always subject to an assessment for impairment as required by paragraph .119. [FAS 19, ¶47, fn3]

future performance. The seller shall account for the funds received as unearned revenue to be recognized as the oil or gas is delivered. The purchaser of such a production payment has acquired an interest in a mineral property that shall be recorded at cost and amortized by the unit-of-production method as delivery takes place. The related reserve estimates and production data shall be reported as those of the purchaser of the production payment and not of the seller (refer to paragraphs .160 through .167).

b. An assignment of the operating interest in an unproved property with retention of a nonoperating interest in return for drilling, development, and operation by the assignee is a pooling of assets in a joint undertaking for which the assignor shall not recognize gain or loss. The assignor's cost of the original interest shall become the cost of the interest retained. The assignee shall account for all costs incurred as specified by paragraphs .106 through .132 and shall allocate none of those costs to the mineral interest acquired. If oil or gas is discovered, each party shall report its share of reserves and production (refer to paragraphs .160 through .167).

c. An assignment of a part of an operating interest in an unproved property in exchange for a "free well" with provision for joint ownership and operation is a pooling of assets in a joint undertaking by the parties. The assignor shall record no cost for the obligatory well; the assignee shall record no cost for the mineral interest acquired. All drilling, development, and operating costs incurred by either party shall be accounted for as provided in paragraphs .106 through .132. If the conveyance agreement requires the assignee to incur geological or geophysical expenditures instead of, or in addition to, a drilling obligation, those costs shall likewise be accounted for by the assignee as provided in paragraphs .106 through .132. If reserves are discovered, each party shall report its share of reserves and production (refer to paragraphs .160 through .167).

d. A part of an operating interest in an unproved property may be assigned to effect an arrangement called a carried interest whereby the assignee (the carrying party) agrees to defray all costs of drilling, developing, and operating the property and is entitled to all of the revenue from production from the property, excluding any third-party interest, until all of the assignee's costs have been recovered, after which the assignor will share in both costs and production. Such an arrangement represents a pooling of assets in a joint undertaking by the assignor and assignee. The carried party shall make no accounting for any costs and revenue until after recoupment (payout) of the carried costs by the carrying party. Subsequent to payout, the carried party shall account for its share of revenue, operating expenses, and (if the agreement provides for subsequent sharing of costs rather than a carried interest) subsequent development costs. During the payout period the carrying party shall record all costs, including those carried, as provided in paragraphs. 106 through .132 and shall record all revenue from the property including that applicable to the recovery of costs carried. The carried party shall report as oil or gas reserves only its share of proved reserves estimated to remain after payout, and unit-of-production amortization of the carried party's property cost shall not commence prior to payout. Prior to payout, the carrying party's reserve estimates and production data shall include the quantities applicable to recoupment of the carried costs (refer to paragraphs .160 through .167).

e. A part of an operating interest owned may be exchanged for a part of an operating interest owned by another party. The purpose of such an arrangement, commonly called a joint venture in the oil and gas industry, often is to avoid duplication of facilities, diversify risks, and achieve operating efficiencies. Such reciprocal conveyances represent exchanges of similar productive assets, and no gain or loss shall be recognized by either party at the time of the transaction. In some joint ventures which may or may not involve an exchange of interests, the parties may share different elements of costs in different proportions. In such an arrangement, a party may acquire an interest in a property or in wells and related equipment that is disproportionate to the share of costs borne by it. As in the case of a carried interest or a free well, each party shall account for its own cost under the provisions of this section. No gain shall be recognized for the acquisition of an interest in joint assets, the cost of which may have been paid in whole or in part by another party.

f. In a unitization, all the operating and nonoperating participants pool their assets in a producing area (normally a field) to form a single unit and in return receive an undivided interest (of the same type as previously held) in that unit. Unitizations generally are undertaken to obtain operating efficiencies and to enhance recovery of reserves, often through improved recovery operations. Participation in the unit is generally proportionate to the oil and gas reserves contributed by each. Because the properties may be in different stages of development at the time of unitization, some participants may pay cash and others may receive cash to equalize contributions of wells and related equipment and facilities with the ownership interests in reserves. In those circumstances, cash paid by a participant shall be recorded as an additional investment in wells and related equipment and facilities, and cash received by a participant shall be recorded as a recovery of cost. The cost of the assets contributed plus or minus cash paid or received is the cost of the participant's undivided interest in the assets of the unit. Each participant shall include its interest in reporting reserve estimates and production data (refer to paragraphs .160 through .167).

g. If the entire interest in an unproved property is sold for cash or cash equivalent, recognition of gain or loss depends on whether, in applying paragraph .119, impairment had been assessed for that property individually or by amortizing that property as part of a group. If impairment was assessed individually, gain or loss shall be recognized. For a property amortized by providing a valuation allowance on a group basis, neither gain nor loss shall be recognized when an unproved property is sold unless the sales price exceeds the original cost of the property, in which case gain shall be recognized in the amount of such excess.

h. If a part of the interest in an unproved property is sold, even though for cash or cash equivalent, substantial uncertainty usually exists as to recovery of the cost applicable to the interest retained. Consequently, the amount received shall be treated as a recovery of cost.[4] However, if the sales price exceeds the carrying amount of a property whose impairment has been assessed individually in accordance with paragraph .119, or exceeds the original cost of a property amortized by providing a valuation allowance on a group basis, gain shall be recognized in the amount of such excess.

i. The sale of an entire interest in a proved property that constitutes a separate amortization base is not one of the types of conveyances described in paragraph .135 or .136. The difference between the amount of sales proceeds and the unamortized cost shall be recognized as a gain or loss.

[4] The carrying amount of the interest retained shall continue to be subject to the assessment for impairment as required by paragraph.119. [FAS 19, ¶47. fn4]

j. The sale of a part of a proved property, or of an entire proved property constituting a part of an amortization base, shall be accounted for as the sale of an asset, and a gain or loss shall be recognized, since it is not one of the conveyances described in paragraph .135 or .136. The unamortized cost of the property or group of properties, a part of which was sold, shall be apportioned to the interest sold and the interest retained on the basis of the fair values of those interests. However, the sale may be accounted for as a normal retirement under the provisions of paragraph .132 with no gain or loss recognized if doing so does not significantly affect the unit-of-production amortization rate.

k. The sale of the operating interest in a proved property for cash with retention of a nonoperating interest is not one of the types of conveyances described in paragraph .135 or .136. Accordingly, it shall be accounted for as the sale of an asset, and any gain or loss shall be recognized. The seller shall allocate the cost of the proved property to the operating interest sold and the nonoperating interest retained on the basis of the fair values of those interests.[5]

l. The sale of a proved property subject to a retained production payment that is expressed as a fixed sum of money payable only from a specified share of production from that property, with the purchaser of the property obligated to incur the future costs of operating the property, shall be accounted for as follows:

   (1) *If satisfaction of the retained production payment is reasonably assured.* The seller of the property, who retained the production payment, shall record the transaction as a sale, with recognition of any resulting gain or loss. The retained production payment shall be recorded as a receivable, with interest accounted for in accordance with the provisions of Section I69, "Interest: Imputation of an Interest Cost." The purchaser shall record as the cost of the assets acquired the cash consideration paid plus the present value (determined in accordance with Section I69) of the retained production payment, which shall be recorded as a payable. The oil and gas reserve estimates and production data, including those applicable to liquidation of the retained production payment, shall be reported by the purchaser of the property (refer to paragraphs .160 through .167).

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[5]A retained production payment denominated in money is not a mineral interest (refer to paragraphs .103 and .134). [FAS 19, ¶47, fn5]

(2) *If satisfaction of the retained production payment is not reasonably assured*. The transaction is in substance a sale with retention of an overriding royalty that shall be accounted for in accordance with paragraph .138(k).

m. The sale of a proved property subject to a retained production payment that is expressed as a right to a specified quantity of oil or gas out of a specified share of future production shall be accounted for in accordance with paragraph .138(k). [FAS 19, ¶47]

Accounting for Income Taxes

.139 Some costs incurred in an enterprise's oil and gas producing activities enter into the determination of taxable income and pretax accounting income in different periods. A principal example is intangible drilling and development costs, which are deductible in determining taxable income when incurred but which, for successful exploratory wells and for all development wells, are capitalized and amortized for financial accounting purposes under the provisions of this section. As another example, some geological and geophysical costs, which are charged to expense when incurred under the provisions of this section, are deferred and deducted in subsequent periods for income tax purposes. [FAS 19, ¶60]

.140 Comprehensive [recognition of deferred taxes] [FAS 19, ¶61] as described in Section I27, "Income Taxes," [FAS 109, ¶288o] shall be followed by oil and gas producing companies for intangible drilling and development costs and other costs incurred that enter into the determination of taxable income and pretax accounting income in different periods. [FAS 19, ¶61]

.141 In applying the comprehensive interperiod income tax allocation provision of the preceding paragraph, the possibility that statutory depletion in future periods will reduce or eliminate [FAS 19, ¶62] taxable income in future years shall be considered in determining whether it is more likely than not that the tax benefits of deferred tax assets will not be realized. However, the tax benefit of the [FAS 109, ¶288(o)] excess of statutory depletion over cost depletion for tax purposes [FAS 19, ¶62] shall not be recognized until [FAS 109, ¶288(o)] the period in which the excess is deducted for income tax purposes. [FAS 19, ¶62]

Impairment Test for Proved Properties and Capitalized Exploration and Development Cost

.141A The provisions of paragraphs .122 through .133 of Section IO8, "Impairment," are applicable to the costs of an enterprise's wells and related equipment and facilities and the costs of the related proved properties. The impairment provisions relating to unproved properties referred to in paragraphs .104, .118 through .120, .122(b), .124, .131, .138(g), and .138(h) of this section remain applicable to unproved properties. [FAS 121, ¶25]

Capitalizing Interest Under Full Cost Method

.142 [Section I67, "Interest: Capitalization of Interest Costs," paragraph .108, provides guidance on accounting for interest costs for enterprises that use the full cost method of accounting for oil and gas producing activities.]

.143-.155 [Deleted 11/82 because of FASB Statement 69, *Disclosures about Oil and Gas Producing Activities.*]

DISCLOSURES

.156 All enterprises engaged in oil and gas producing activities shall disclose in their financial statements the method of accounting for costs incurred in those activities and the manner of disposing of capitalized costs relating to those activities. [FAS 69, ¶6]

.157 In addition, publicly traded enterprise[6] that have significant oil and gas producing activities shall disclose **with complete sets of annual financial statements**[7]the information required by paragraphs .160 through

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[6]For purposes of this section, a publicly traded enterprise is a business enterprise (a) whose securities are traded in a public market on a domestic stock exchange or in the domestic over-the-counter market (including securities quoted only locally or regionally) or (b) whose financial statements are filed with a regulatory agency in preparation for the sale of any class of securities in a domestic market. [FAS 69, ¶1, fn2]

[7]Section S20, "Segment of Business Reporting:" paragraph .401, refers to a complete set of financial statements as "a set of financial statements (including necessary footnotes) that present financial position, results of operations, and

.184. Those disclosures relate to the following and are considered to be supplementary information:

a. Proved oil and gas reserve quantities
b. Capitalized costs relating to oil and gas producing activities
c. Costs incurred for property acquisition, exploration, and development activities.
d. Results of operations for oil and gas producing activities
e. A standardized measure of discounted future net cash flows relating to proved oil and gas reserve quantities [FAS 69, ¶7]

.158 For purposes of this section, an enterprise is regarded as having significant oil and gas producing activities if it satisfies one or more of the following tests. The tests shall be applied separately for each year for which a complete set of annual financial statements is presented.

a. Revenues from oil and gas producing activities, as defined in paragraph .175 (including both sales to unaffiliated customers and sales or transfers to the enterprise's other operations), are 10 percent or more of the combined revenues (sales to unaffiliated customers and sales or transfers to the enterprise's other operations) of all of the enterprise's **industry segments**.[8]
b. Results of operations for oil and gas producing activities, excluding the effect of income taxes, are 10 percent or more of the greater of:
   (1) The combined operating profit of all industry segments that did not incur an operating loss
   (2) The combined operating loss of all industry segments that did incur an operating loss

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[FAS 69, ¶1, fn3] cash flows [FAS 95, ¶152] in conformity with generally accepted accounting principles." [FAS 69, ¶1, fn3]

[8]For purposes of this section, an industry segment is a component of an enterprise engaged in providing a product or service or a group of related products or services primarily to external customers (that is, customers outside the enterprise) for a profit. [FAS 131, ¶133, (a)]

c. The identifiable assets of oil and gas producing activities (tangible and intangible enterprise assets that are used by oil and gas producing activities, including an allocated portion of assets used jointly with other operations) are 10 percent or more of the assets of the enterprise, excluding assets used exclusively for general corporate purposes. [FAS 131, ¶133(b)]

.159 The disclosures set forth in this section are not required in interim financial reports. However, interim financial reports shall include information about a major discovery or other favorable or adverse event that causes a significant change from the information presented in the most recent annual financial report concerning oil and gas reserve quantities. [FAS 69, ¶9]

Disclosure of Proved Oil and Gas Reserve Quantities

.160 Net quantities of an enterprise's interests in proved reserves and proved developed reserves of (a) crude oil (including condensate and natural gas liquids)[9] and (b) natural gas shall be disclosed as of the beginning and the end of the year. "Net" quantities of reserves include those relating to the enterprise's operating and nonoperating interests in properties as defined in paragraph .103(a). Quantities of reserves relating to royalty interests owned shall be included in "net" quantities if the necessary information is available to the enterprise; if reserves relating to royalty interests owned are not included because the information is unavailable, that fact and the enterprise's share of oil and gas produced for those royalty interests shall be disclosed for the year. "Net" quantities shall not include reserves relating to interests of others in properties owned by the enterprise. [FAS 69, ¶10]

.161 Changes in the net quantities of an enterprise's proved reserves of oil and of gas during the year shall be disclosed. Changes resulting from each of the following shall be shown separately with appropriate explanation of significant changes:

a. *Revisions of previous estimates*. Revisions represent changes in previous estimates of proved reserves, either upward or downward,

[9]If significant, the reserve quantity information shall be disclosed separately for natural gas liquids [FAS 69, ¶10, fn5]

resulting from new information (except for an increase in proved acreage) normally obtained from development drilling and production history or resulting from a change in economic factors.

b. *Improved recovery*. Changes in reserve estimates resulting from application of improved recovery techniques shall be shown separately, if significant. If not significant, such changes shall be included in revisions of previous estimates.
c. *Purchases of minerals in place.*
d. *Extensions and discoveries.* Additions to proved reserves that result from (1) extension of the proved acreage of previously discovered (old) reservoirs through additional drilling in periods subsequent to discovery and (2) discovery of new fields with proved reserves or of new reservoirs of proved reserves in old fields.
e. *Production.*
f. *Sales of minerals in place*. [FAS 69, ¶11]

.162 If an enterprise's proved reserves of oil and of gas are located entirely within its home country, that fact shall be disclosed. If some or all of its reserves are located in foreign countries, the disclosures of net quantities of reserves of oil and of gas and changes in them required by paragraphs .160 and .161 shall be separately disclosed for (a) the enterprise's home country (if significant reserves are located there) and (b) each foreign geographic area in which significant reserves are located. Foreign geographic areas are individual countries or groups of countries as appropriate for meaningful disclosure in the circumstances. [FAS 69, ¶12]

.163 Net quantities disclosed in conformity with paragraphs .160 through .162 Shall not include oil or gas subject to purchase under long-term supply, purchase, or similar agreements and contracts, including such agreements with governments or authorities. However, quantities of oil or gas subject to such agreements with governments or authorities as of the end of the year, and the net quantity of oil or gas received under the agreements during the year, shall be separately disclosed if the enterprise participates in the operation of the properties in which the oil or gas is located or otherwise serves as the "producer" of those reserves, as opposed, for example, to being an independent purchaser, broker, dealer, or importer. [FAS 69. ¶13]

.164 In determining the reserve quantities to be disclosed in conformity with paragraphs .160 through .163:

a. If the enterprise issues consolidated financial statements, 100 percent of the net reserve quantities attributable to the parent company and 100 percent of the net reserve quantities attributable to its consolidated subsidiaries (whether or not wholly owned) shall be included. If a significant portion of those reserve quantities at the end of the year is attributable to a consolidated subsidiary(ies) in which there is a significant minority interest, that fact and the approximate portion shall be disclosed.
b. If the enterprise's financial statements include investments that are proportionately consolidated, the enterprise's reserve quantities shall include its proportionate share of the investees' net oil and gas reserves.
c. If the enterprise's financial statements include investments that are accounted for by the equity method, the investees' net oil and gas reserve quantities shall not be included in the disclosures of the enterprise's reserve quantities. However, the enterprise's (investor's) share of the investees' net oil and gas reserve quantities shall be separately disclosed as of the end of the year. [FAS 69, ¶14]

.165 In reporting reserve quantities and changes in them, oil reserves and natural gas liquids reserves shall be stated in barrels, and gas reserves in cubic feet. [FAS 69, ¶15]

.166 If important economic factors or significant uncertainties affect particular components of an enterprise's proved reserves, explanation shall be provided. Examples include unusually high expected development or lifting costs, the necessity to build a major pipeline or other major facilities before production of the reserves can begin, and contractual obligations to produce and sell a significant portion of reserves at prices that are substantially below those at which the oil or gas could otherwise be sold in the absence of the contractual obligation. [FAS 69, ¶16]

.167 If a government restricts the disclosure of estimated reserves for properties under its authority, or of amounts under long-term supply, purchase, or similar agreements or contracts, or if the government requires the disclosure of reserves other than proved, the enterprise shall indicate that the disclosed reserve estimates or amounts do not include figures for the named country or that reserve estimates include reserves other than proved. [FAS 69, ¶17]

Disclosure of Capitalized Costs Relating to Oil and Gas Producing Activities

.168 The aggregate capitalized costs relating to an enterprise's oil and gas producing activities (refer to paragraph .103) and the aggregate related accumulated depreciation, depletion, amortization, and valuation allowances shall be disclosed as of the end of the year. Section D40, "Depreciation," paragraph .105, requires disclosure of "balances of major classes of depreciable assets, by nature or function." Thus, separate disclosure of capitalized costs for asset categories (a) through (d) in paragraph .103 or for a combination of those categories often may be appropriate. [FAS 69, ¶18]

.169 If significant, capitalized costs of unproved properties shall be separately disclosed. Capitalized costs of support equipment and facilities may be disclosed separately or included, as appropriate, with capitalized costs of proved and unproved properties. [FAS 69, ¶19]

.170 If the enterprise's financial statements include investments that are accounted for by the equity method, the enterprise's share of the investees' net capitalized costs relating to oil and gas producing activities as of the end of the year shall be separately disclosed. [FAS 69, ¶20]

Disclosure of Costs Incurred in Oil and Gas Property Acquisition, Exploration, and Development Activities

.171 Each of the following types of costs for the year shall be disclosed (whether those costs are capitalized or charged to expense at the time they are incurred under the provisions of paragraphs .106 through .113):[10]

a. Property acquisition costs
b. Exploration costs
c. Development costs [FAS 69, ¶21]

[10] As defined in the paragraphs cited, exploration and development costs include depreciation of support equipment and facilities used in those activities and do not include the expenditures to acquire support equipment and facilities. [FAS 69. ¶21. fn6]

.172 If some or all of those costs are incurred in foreign countries, the amounts shall be disclosed separately for each of the geographic areas for which reserve quantities are disclosed (refer to paragraph .162). If significant costs have been incurred to acquire mineral interests that have proved reserves, those costs shall be disclosed separately from the costs of acquiring unproved properties. [FAS 69, ¶22]

.173 If the enterprise's financial statements include investments that are accounted for by the equity method, the enterprise's share of the investees' property acquisition, exploration, and development costs incurred in oil and gas producing activities shall be separately disclosed for the year, in the aggregate and for each geographic area for which reserve quantities are disclosed (refer to paragraph .162). [FAS 69, ¶23]

Disclosure of the Results of Operations for Oil and Gas Producing Activities

.174 The results of operations for oil and gas producing activities shall be disclosed for the year. That information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed (refer to paragraph .162). The following information relating to those activities shall be presented:[11]

a. Revenues
b. Production (lifting) costs
c. Exploration expenses[12]

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[11]If oil and gas producing activities represent substantially all of the business activities of the reporting enterprise and those oil and gas activities are located substantially in a single geographic area, the information required by paragraphs .174 through .179 need not be disclosed if that information is provided elsewhere in the financial statements. If oil and gas producing activities constitute an operating segment, as discussed in paragraphs .109 through .123 of Section S30, "Segment Disclosures and Related Information," information about the results of operations required by paragraphs .174 through .179 of this section may be included with segment information disclosed elsewhere in the financial report. [FAS 131, ¶133, (c)]

[12]Generally, only enterprises utilizing the successful efforts accounting method will have exploration expenses to disclose, since enterprises utilizing the full cost accounting method generally capitalize all exploration costs when incurred and subsequently reflect those costs in the determination of earnings through

d. Depreciation, depletion, and amortization, and valuation provisions
e. Income tax expenses
f. Results of operations for oil and gas producing activities (excluding corporate overhead and interest costs) [FAS 69, ¶24]

.175 Revenues shall include sales to unaffiliated enterprises and sales or transfers to the enterprise's other operations (for example, refineries or chemical plants). Sales to unaffiliated enterprises and sales or transfers to the enterprise's other operations shall be disclosed separately. Revenues shall include sales to unaffiliated enterprises attributable to net working interests, royalty interests, oil payment interests, and net profits interests of the reporting enterprise. Sales or transfers to the enterprise's other operations shall be based on market prices determined at the point of delivery from the producing unit. Those market prices shall represent prices equivalent to those that could be obtained in an arm's-length transaction. Production or severance taxes shall not be deducted in determining gross revenues, but rather shall be included as part of production costs. Royalty payments and net profits disbursements shall be excluded from gross revenues. [FAS 69, ¶25]

.176 Income taxes shall be computed using the statutory tax rate for the period, applied to revenues less production (lifting) costs, exploration expenses, depreciation, depletion, and amortization, and valuation provisions. Calculation of income tax expenses shall reflect [FAS 69, ¶26] tax deductions, [FAS 109, ¶288u] tax credits and allowances relating to the oil and gas producing activities that are reflected in the enterprise's consolidated income tax expense for the period. [FAS 69, ¶26]

.177 Results of operations for oil and gas producing activities are defined as revenues less production (lifting) costs, exploration expenses, depreciation, depletion, and amortization, valuation provisions, and income tax expenses. General corporate overhead and interest costs[13] shall not be deducted in computing the results of operations for an enterprise's oil and gas producing activities. However, some expenses incurred at an enterprise's central administrative office may not be general corporate expenses, but rather may be operating expenses of oil and gas producing

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depreciation, depletion, and amortization, and valuation provisions. [FAS 69, ¶24, fn8]

[13]The disposition of interest costs that have been capitalized as part of the cost of acquiring qualifying assets used in oil and gas producing activities shall be the same as that of other components of those assets' costs. [FAS 69, ¶27, fn9]

activities, and therefore should be reported as such. The nature of an expense rather than the location of its incurrence shall determine whether it is an operating expense. Only those expenses identified by their nature as operating expenses shall be allocated as operating expenses in computing the results of operations for oil and gas producing activities. [FAS 69, ¶27]

.178 The amounts disclosed in conformity with paragraphs .174 through .177 shall include an enterprise's interests in proved oil and gas reserves (refer to paragraph .160) and in oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the enterprise participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (refer to paragraph .163). [FAS 69, ¶28]

.179 If the enterprise's financial statements include investments that are accounted for by the equity method, the investees' results of operations for oil and gas producing activities shall not be included in the enterprise's results of operations for oil and gas producing activities. However, the enterprise's share of the investees' results of operations for oil and gas producing activities shall be separately disclosed for the year, in the aggregate and by each geographic area for which reserve quantities are disclosed (refer to paragraph .162). [FAS 69, ¶29]

Disclosure of a Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserve Quantities

.180 A standardized measure of discounted future net cash flows relating to an enterprise's interests in (a) proved oil and gas reserves (refer to paragraph .160) and (b) oil and gas subject to purchase under long-term supply, purchase, or similar agreements and contracts in which the enterprise participates in the operation of the properties on which the oil or gas is located or otherwise serves as the producer of those reserves (refer to paragraph .163) shall be disclosed as of the end of the year. The standardized measure of discounted future net cash flows relating to those two types of interests in reserves may be combined for reporting purposes. The following information shall be disclosed in the aggregate and for each geographic area for which reserve quantities are disclosed in accordance with paragraph .162:

a. *Future cash inflows*. These shall be computed by applying year-end prices of oil and gas relating to the enterprise's proved reserves to the year-end quantities of those reserves. Future price changes shall be considered only to the extent provided by contractual arrangements in existence at year-end.
b. *Future development and production costs*. These costs shall be computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions. If estimated development expenditures are significant, they shall be presented separately from estimated production costs.
c. *Future income tax expenses*. These expenses shall be computed by applying the appropriate year-end statutory tax rates, with consideration of future tax rates already legislated, to the future pretax net cash flows relating to the enterprise's proved oil and gas reserves, less the tax basis of the properties involved. The future income tax expenses shall give effect to [FAS 69, ¶30] tax deductions, [FAS 109, ¶288u] tax credits and allowances relating to the enterprise's proved oil and gas reserves.
d. *Future net cash flows*. These amounts are the result of subtracting future development and production costs and future income tax expenses from future cash inflows.
e. *Discount*. This amount shall be derived from using a discount rate of 10 percent a year to reflect the timing of the future net cash flows relating to proved oil and gas reserves.
f. *Standardized measure of discounted future net cash flows*. This amount is the future net cash flows less the computed discount. [FAS 69, ¶30]

.181 If a significant portion of the economic interest in the consolidated standardized measure of discounted future net cash flows reported is attributable to a consolidated subsidiary(ies) in which there is a significant minority interest, that fact and the approximate portion shall be disclosed. [FAS 69, ¶31]

.182 If the financial statements include investments that are accounted for by the equity method, the investees' standardized measure of discounted future net cash flows relating to proved oil and gas reserves shall not be included in the disclosure of the enterprise's standardized measure. However, the enterprise's share of the investees' standardized measure of discounted future net cash flows shall be separately disclosed for the year, in the aggregate and by each geographic area for which quantities are disclosed (refer to paragraph .162). [FAS 69, ¶32]

.183 The aggregate change in the standardized measure of discounted future net cash flows shall be disclosed for the year. If individually significant, the following sources of change shall be presented separately:

a. Net change in sales and transfer prices and in production (lifting) costs related to future production
b. Changes in estimated future development costs
c. Sales and transfers of oil and gas produced during the period
d. Net change due to extensions, discoveries, and improved recovery
e. Net change due to purchases and sales of minerals in place
f. Net change due to revisions in quantity estimates
g. Previously estimated development costs incurred during the period
h. Accretion of discount
i. Other--unspecified
j. Net change in income taxes

In computing the amounts under each of the above categories, the effects of changes in prices and costs shall be computed before the effects of changes in quantities. As a result, changes in quantities shall be stated at year-end prices and costs. The change in computed income taxes shall reflect the effect of income taxes incurred during the period as well as the change in future income tax expenses. Therefore, all changes except income taxes shall be reported pretax. [FAS 69, ¶33]

.184 Additional information necessary to prevent the disclosure of the standardized measure of discounted future net cash flows and changes therein from being misleading also shall be provided. [FAS 69, ¶34]

SUMMARIES AND ILLUSTRATIONS OF CERTAIN DISCLOSURES ABOUT OIL AND GAS PRODUCING ACTIVITIES

.185 Following are summaries and illustrations of certain of the disclosure requirements for oil and gas producing activities required by this section.

	Disclosure Illustration
Accounting Method	
Method of accounting for costs incurred and the manner of disposing of capitalized costs relating to oil and gas producing activities	—
Capitalized Costs	
Aggregate amount of capitalized costs and related accumulated depreciation, depletion, and amortization, and valuation allowances (If significant, capitalized costs of unproved properties shall be separately disclosed.)	1
Enterprise's share of equity method investees' capitalized costs in the aggregate at the end of the year	1

	Disclosure Illustration
Costs Incurred in Oil and Gas Property Acquisition, Exploration, and Development	
Costs incurred in oil and gas producing activities in the aggregate, by type, and by geographic area during the year (If significant, costs of acquiring existing mineral interests that have proved reserves shall be disclosed separately from the costs of acquiring unproved properties.)	2
Enterprise's share of equity method investees' costs incurred in the aggregate and by geographic area during the year	2
Results of Operations	
Results of operations for the year from oil and gas producing activities and the major components of those activities in the aggregate and by geographic area	3
Enterprise's share of equity method investees' results of operations for the year from oil and gas producing activities in the aggregate and by geographic area	3
Reserve Quantity Information	
Net quantities of proved reserves and proved developed reserves at the beginning and end of the year and changes in proved reserves in the aggregate, by type, and by geographic area	4

	Disclosure Illustration
Reserves subject to purchase under supply agreements with governments or authorities in which the enterprise acts as producer, and reserves received under those agreements during the year in the aggregate and by geographic area	4
Enterprise's share of equity method investees' proved reserves at the end of the year in the aggregate and by geographic area	4
Approximate portion of reserve quantities at the end of the year attributable to a consolidated subsidiary(ies) in which there is a significant minority interest	4
Important economic factors and significant uncertainties affecting an enterprise's proved reserves	—
Governmental restrictions on reporting reserve information	—
Standardized Measure of Discounted Future Net Cash Flows	
Standardized measure of discounted future net cash flows and major components of that calculation relating to proved reserve quantities (including those relating to long-term supply agreements for which the enterprise acts as producer) at the end of the year in the aggregate and by geographic area, based on year-end prices, costs, and statutory tax rates (adjusted for [FAS 69, ¶40] tax deductions [FAS 109, ¶288u]) and a 10-percent annual discount rate	5
Enterprise's share of equity method investees' standardized measure of discounted future net cash flows in the aggregate and by geographic area	5

	Disclosure Illustration
Approximate portion of economic interests in the consolidated standardized measure of discounted future net cash flows at the end of the year attributable to a consolidated subsidiary(ies) in which there is a significant minority interest	5
Summary of changes in the standardized measure of discounted future net cash flows during the year in the aggregate	5
Additional information concerning the standardized measure of discounted future net cash flows required to prevent the information from being misleading [FAS 69, ¶40]	—

.186 The following illustrations present formats that may be used to disclose certain information required by this section when a complete set of annual financial statements is presented for one year.

Illustration I
Capitalized Costs Relating to
Oil and Gas Producing Activities
at December 31, 19XX

	Total
Unproved oil and gas properties	$X
Proved oil and gas properties	X
	X
Accumulated depreciation, depletion, and amortization, and valuation allowances	X
Net capitalized costs	$X
Enterprise's share of equity method investees' net capitalized costs	$X

Illustration 2
Costs Incurred in Oil and Gas Property Acquisition, Exploration, and Development Activities for the Year Ended December 31, 19XX

	Total	United States	Foreign Geographic Area A	Foreign Geographic Area B	Other Foreign Geographic Areas
Acquisition of properties					
- Proved	$X	$X	$X	$X	$X
- Unproved	X	X	X	X	X
Exploration costs	X	X	X	X	X
Development costs	X	X	X	X	X
Enterprise's share of equity method investees' costs of property acquisition, exploration, and development	X	X	X	X	X

Illustration 3

Results of Operations for Producing Activities for the Year Ended December 31, 19XX

	Total	United States	Foreign Geographic Area A	Foreign Geographic Area B	Other Foreign Geographic Areas
Revenues					
Sales	$X	$X	$X	$X	$X
Transfers	X	X	X	X	X
Total	X	X	X	X	X
Production costs	(X)	(X)	(X)	(X)	(X)
Exploration expenses	(X)	(X)	(X)	(X)	(X)
Depreciation, depletion, and amortization, and valuation provisions	(X)	(X)	(X)	(X)	(X)
	X	X	X	X	X
Income tax expenses	(X)	(X)	(X)	(X)	(X)
Results of operations from producing activities (excluding corporate overhead and interest costs)	$X	$X	$X	$X	$X
Enterprise's share of equity method investees' results of operations for producing activities	$X	$X	$X	$X	$X

Illustration 4
Reserve Quantity Information*
for the Year Ended December 31, 19XX

	Total		United States		Foreign Geographic Area A		Foreign Geographic Area B		Other Foreign Geographic Areas	
	Oil	**Gas**	**Oil**	**Gas**	**Oil**	**Gas**	**Oil**	**Gas**	**Oil**	**Gas**
Proved developed and undeveloped reserves:										
Beginning of year	X	X	X	X	X	X	X	X	X	X
Revisions of previous estimates	X	X	X	X	X	X	X	X	X	X
Improved recovery	X	X	X	X	X	X	X	X	X	X
Purchases of minerals in place	X	X	X	X	X	X	X	X	X	X
Extensions and discoveries	X	X	X	X	X	X	X	X	X	X
Production	(X)	(X)	(X)	(X)	(X)	(X)	(X)	(X)	(X)	(X)
Sales of minerals in place	(X)	(X)	(X)	(X)	(X)	(X)	(X)	(X)	(X)	(X)
End of year	X†	X	X	X	X	X	X	X	X	X
Proved developed reserves:										
Beginning of year	X	X	X	X	X	X	X	X	X	X
End of year	X	X	X	X	X	X	X	X	X	X
Oil and gas applicable to long-term supply agreements with governments or authorities in which the enterprise acts as producer:										
Proved reserves--end of year	X	X		X	X					
Received during the year	X	X		X	X					
Enterprise's proportional interest in reserves of investees accounted for by the equity method--end of year	X	X	X	X	X	X	X	X	X	X

*Oil reserves stated in barrels; gas reserves stated in cubic feet.

†Includes reserves of X barrels attributable to a consolidated subsidiary in which there is an X-Percent minority interest. [FAS 69, ¶41]

Illustration 5

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Gas Reserves at December 31, 19XX

	Total	United States	Foreign Geographic Area A	Foreign Geographic Area B	Other Foreign Geographic Areas
Future cash inflows*	$X	$X	$X	$X	
Future production and development costs*	(X)	(X)	(X)	(X)	
Future income tax expenses*	(X)	(X)	(X)	(X)	
Future net cash flows	X	X	X	X	
10% annual discount for estimated timing of cash flows	(X)	(X)	(X)	(X)	
Standardized measure of discounted future net cash flows	$X†	$X	$X	$X	$X
Enterprise's share of equity method investees' standardized measure of discounted future net cash flows	$X	$X	$X	$X	$X

Illustration 5
(continued)
Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Gas Reserves at December 31, 19XX

The following are the principal sources of change in the standardized measure of discounted future net cash flows during
19XX:

Sales and transfers of oil and gas produced, net of production costs	$(X)
Net changes in prices and production costs	X
Extensions, discoveries, and improved recovery, less related costs	X
Development costs incurred during the period	(X)
Revisions of previous quantity estimates	X
Accretion of discount	X
Net change in income taxes	X
Other	X

[FAS 69, ¶41]

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*Future net cash flows were computed using year-end prices and costs, and year-end statutory tax rates (adjusted for [FAS 69, ¶41] tax deductions [FAS 109, ¶288u]) that relate to existing proved oil and gas reserves in which the enterprise has mineral interests, including those mineral interests related to long-term supply agreements with governments for which the enterprise serves as the producer of the reserves. [FAS69, ¶41]

†Includes $X attributable to a consolidated subsidiary in which there is an X-percent minority interest. [FAS 69, ¶41]

Glossary

.400 **Complete set of financial statements.** A set of financial statements (including necessary footnotes) that present financial position, results of operations, and [FAS 69, ¶1, fn3] cash flows [FAS 95, ¶152] in conformity with generally accepted accounting principles. [FAS 69, ¶1, fn3]

.401 **Development well.** A well drilled within the **proved area** of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive. [FAS 19, ¶274]

.402 **Exploratory well.** A well that is not a development well, a service well, or a stratigraphic test well, as those terms are defined in this section. [FAS 19, ¶274]

.403 **Field.** An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature or stratigraphic condition, or both. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms structural feature and stratigraphic condition are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays, areas of interest, etc. [FAS 19, ¶272]

.403A **Foreign geographic area.** Individual countries or groups of countries as appropriate for meaningful disclosure in the circumstances. [FAS 69, ¶12]

.403B **Industry segment.** A component of an enterprise engaged in providing a product or service or a group of related products and services primarily to unaffiliated customers (i.e., customers outside the enterprise) for a profit. [FAS 69, ¶8, fn4]

.403C **Oil and gas producing activities.** Those activities [that] involve the acquisition of mineral interests in properties, exploration (including prospecting), development, and production of crude oil, including condensate and natural gas liquids, and natural gas. [FAS 19, ¶1]

.404 **Proved area.** The part of a property to which proved reserves have been specifically attributed. [FAS 19, ¶275]

.405 **Proved reserves.**[14]

a. *Proved oil and gas reserves*. The estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, that is, prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided only by contractual arrangements but not on escalations based upon future conditions.
   (1) Reservoirs are considered proved if economic producibility is supported by either actual production or conclusive formation test. The area of a reservoir considered proved includes (a) that portion delineated by drilling and defined by gas-oil or oil-water contacts, if any, or both, and (b) the immediately adjoining portions not yet drilled, but which can be reasonably judged as economically productive on the basis of available geological and engineering data. In the absence of information on fluid contacts, the lowest known structural occurrence of hydrocarbons controls the lower proved limit of the reservoir.
   (2) Reserves that can be produced economically through application of improved recovery techniques (such as fluid injection) are included in the *proved* classification if successful testing by a pilot project, or the operation of an installed program in the reservoir, provides support for the engineering analysis on which the project or program was based.

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[14]The following definitions of proved reserves are those developed by the Department of Energy for its Financial Reporting System and adopted by the SEC on December 19, 1978 in Accounting Series Release 257. Reference should be made to the SEC's reporting requirements for revisions that may have been made since the issuance of ASR 257. [FAS 25, ¶34]

(3) Estimates of proved reserves do not include the following: (a) oil that may become available from known reservoirs but is classified separately as *indicated additional reserves*; (b) crude oil, natural gas, and natural gas liquids, the recovery of which is subject to reasonable doubt because of uncertainty as to geology, reservoir characteristics, or economic factors; (c) crude oil, natural gas, and natural gas liquids that may occur in undrilled prospects; and (d) crude oil, natural gas, and natural gas liquids that may be recovered from oil shales, coal, gilsonite, and other such sources.

b. *Proved developed oil and gas reserves*. Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery should be included as *proved developed reserves* only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

c. *Proved undeveloped reserves.* Proved undeveloped oil and gas reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells for which a relatively major expenditure is required for recompletion. Reserves on undrilled acreage should be limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only if it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir. [FAS 25, ¶34]

.405A **Publicly traded enterprise.** A business enterprise (a) whose securities are traded in a public market on a domestic stock exchange or in the domestic over-the-counter market (including securities quoted only locally or regionally) or (b) whose financial statements are filed with a regulatory agency in preparation for the sale of any class of securities in a domestic market. [FAS 69, ¶1, fn2]

.406 **Reservoir.** A porous and permeable underground formation containing a natural accumulation of producible oil or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs. [FAS 19, ¶273]

.407 **Service well.** A service well is a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane, or flue gas), water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for combustion. [FAS 19, ¶274]

.408 **Stratigraphic test well.** A stratigraphic test is a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intention of being completed for hydrocarbon production. This classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. For purposes of this section, stratigraphic test wells (sometimes called expendable wells) are classified as follows:

a. *Exploratory-type stratigraphic test well*. A stratigraphic test well not drilled in a proved area.
b. *Development-type stratigraphic test well*. A stratigraphic test well drilled in a proved area. [FAS 19, ¶274]

APPENDIX 4: ILLUSTRATIVE E&P FINANCIAL STATEMENTS AND SUPPLEMENTAL DISCLOSURES

The financial statements presented in the following pages are designed to illustrate oil and gas disclosure information for both successful efforts accounting and full cost accounting purposes. The financial statements are intended to be representative of only the oil and gas aspects of reporting and therefore are not complete in any way as to various classified line item amounts, footnotes, and other disclosures that may be required by generally accepted accounting principles, the Financial Accounting Standards Board, the Securities and Exchange Commission, or other organizations. Users should not attempt to create any correlation between the successful efforts and the full cost amounts as presented in the separate statements.

Many disclosures are not required if immaterial to the financial statements. Any disclosure made in these illustrative financial statements is for illustrative purposes only and is not indicative of such disclosure being material to the financial statements.

See Chapters Twenty-Eight and Twenty-Nine for examples of variations of key disclosures presented in this Appendix.

Our Oil Company
Consolidated Balance Sheet
December 31, 2000

	Successful Efforts	Full Cost
Assets	(in thousands)	
Current assets		
Cash and cash equivalents	$ 25,500	$ 25,500
Trade receivables	42,550	42,550
Swap receivables	116,300	116,300
Inventories	9,100	9,100
Total current assets	193,450	193,450
Oil and gas properties (Notes 3 and 4)	750,100	-
Costs being amortized	-	1,160,050
Costs not being amortized*	-	72,010
	750,100	1,232,060
Less accumulated amortization	(545,700)	(838,240)
Net oil and gas properties	204,400	393,820
Receivables under gas balancing arrangements	3,000	3,000
Other assets	2,000	2,000
Total Assets	$ 402,850	$ 592,270
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable	$ 43,500	$ 43,500
Accrued liabilities	6,100	6,100
Current portion of long-term debt (Note 5)	7,500	7,500
Drilling advances (Note 6)	3,780	3,780
Income taxes payable	3,170	3,170
Total current liabilities	64,050	64,050
Long-term debt (Note 5)	76,500	76,500
Accrued restoration and abandonment costs	13,650	13,650
Deferred income taxes (Note 7)	27,600	69,350
Deferred revenue (Note 4)	24,400	24,400
Commitments and contingencies (Note 9)**	-	-
Total liabilities	206,200	247,950
Shareholders' equity		
Common stock, par value $1 per share; 10,000,000 shares authorized, issued and outstanding	10,000	10,000
Additional paid-in capital	45,100	45,100
Retained earnings	25,250	172,920
Accumulated other comprehensive income	116,300	116,300
Total shareholders' equity	196,650	344,320
Total Liabilities and Shareholders' Equity	$ 402,850	$ 592,270

The accompanying notes are an integral part of these consolidated financial statements.

* Disclosed for full cost, pursuant to Reg. S-X Rule 4-10(c)(7)(ii).

** With the exception of the commitments and contingencies line, many companies no longer include note references on the face of the financial statements.

Our Oil Company
Consolidated Statement of Income
Year Ended December 31, 2000

	Successful Efforts	Full Cost
	(in thousands, except per share amounts)	
Revenues		
Oil and gas sales	$ 159,990	$ 159,990
Gain on sale of oil and gas properties (Note 4)	20,500	-
Other	6,050	6,050
Total revenues	186,540	166,040
Expenses		
Operating costs	25,320	25,320
Production taxes	9,200	9,200
Exploration	49,770	-
Amortization	15,650	31,920
Proved property impairment (Note 10)	2,000	-
General and administrative	21,220	21,220
Total expenses	123,160	87,660
Income from operations	63,380	78,380
Other revenues and expenses		
Interest income	1,190	1,190
Interest expense	(9,450)	(9,450)
Capitalized interest	1,000	1,000
Total other	(7,260)	(7,260)
Income before provision for income taxes	56,120	71,120
Provision for income taxes (Note 7)		
Current	13,550	13,550
Deferred	5,650	10,170
Total income taxes	19,200	23,720
Net income	$ 36,920	$ 47,400
Earnings per common share	$3.69	$4.74

The accompanying notes are an integral part of these consolidated financial statement

Our Oil Company
Consolidated Statement of Cash Flows*
Year Ended December 31, 2000

	Successful Efforts	Full Cost
	(in thousands)	
Operating activities		
Net income	$ 36,920	$ 47,400
Adjustments for noncash transactions		
Gain on sale of oil and gas properties	(20,500)	-
Dry holes and lease impairments	10,500	-
Amortization	15,650	31,920
Proved property impairments	2,000	-
Deferred income taxes	5,650	10,170
Increase in receivables	(12,100)	(12,100)
Decrease in inventories	1,900	1,900
Increase in accounts payable	1,450	1,450
Increase in drilling advances	2,220	2,220
Increase in accrued liabilities	550	550
Increase in current portion of long-term debt	2,100	2,100
Increase in income taxes payable	1,780	1,780
Net cash provided by operating activities	48,120	87,390
Investing activities		
Capital expenditures for oil and gas properties	(112,280)	(151,550)
Proceeds from sale of oil and gas properties (Note 4)	85,000	85,000
Net cash used in investing activities	(27,280)	(66,550)
Financing activities		
Additions to long-term debt	33,600	33,600
Reduction of long-term debt	(41,100)	(41,100)
Net cash used in financing activities	(7,500)	(7,500)
Net increase in cash	13,340	13,340
Cash and cash equivalents, beginning of year	12,160	12,160
Cash and cash equivalents, end of year	$ 25,500	$ 25,500

The accompanying notes are an integral part of these consolidated financial statements.

* Not illustrated is the supplemental cash flow information on payments of interest (net of amount capitalized) and of income taxes required by Current Text C25.127 and commonly disclosed in a note to the financial statements. See C25.138B for an illustration.

The statement of changes in shareholders' equity is no different for an E&P company and is also not illustrated in this Appendix.

Our Oil Company
Notes to Consolidated Financial Statements
Year Ended December 31, 2000

1. Summary of Significant Accounting Policies

Nature of Operations

The Company is a U.S. petroleum exploration and production company engaged in the acquisition, exploration, and development of properties for the production of crude oil and natural gas from underground reservoirs. The Company's properties are located primarily in Texas, Louisiana, Oklahoma, Wyoming, and the Gulf Coast offshore of Texas and Louisiana. The produced crude oil and natural gas are sold to domestic crude oil refineries, gas processors, and gas marketers. Less than ten percent of the Company's sales are attributable to its largest customer.

Principles of Consolidation

The consolidated financial statements include the accounts of the Company and of those significant subsidiaries owned directly or indirectly more than 50 percent by the Company and for which minority shareholders do not possess the right to participate in significant management decisions.

Cash and Cash Equivalents

Highly liquid investments with original maturities of less than three months are considered cash equivalents and are stated at cost which approximates market value.

Inventories

Inventories consist principally of oil field tubular goods and production equipment stated at the lower of weighted average cost or market.

Oil and Gas Properties
(Successful Efforts)

The Company follows the successful efforts method of accounting for oil and gas property acquisition, exploration, development, and production activities.

Capitalization Policies: Oil and gas property acquisition costs, exploration well costs, and development costs are capitalized as incurred. Related interest expense incurred during property exploration and development activities is capitalized as a cost of such activity. Net capitalized costs of unproved property and exploration well costs are reclassified as proved property and well costs when related proved reserves are found. If an exploration well is unsuccessful in finding proved reserves, the capitalized well costs are charged to exploration expense. Other exploration costs, including geological and geophysical costs, and the costs of carrying unproved property are charged to exploration expense as incurred. Costs to operate and maintain wells and field equipment are expensed as incurred.

Amortization Policies: Capitalized proved property acquisition costs are amortized by field using the unit-of-production method based on proved reserves. Capitalized exploration well costs and development costs (plus estimated future equipment dismantlement, surface restoration, and property abandonment costs, net of equipment salvage values) are amortized similarly by field based on proved developed reserves.

Impairment Policies: Long-lived assets used in operations are assessed for impairment whenever changes in facts and circumstances indicate a possible significant deterioration in the future cash flows expected to be generated by an asset group. If, upon review, the sum of the undiscounted pretax cash flows are less than the carrying value of the asset group, the carrying value is written down to estimated fair value. Individual assets are grouped for impairment purposes at the lowest level for which there are identifiable cash flows that are largely independent of the cash flows of other groups of assets – generally on a field-by field basis. The fair value of impaired assets is determined based on quoted market prices in active markets, if available, or upon the present values of expected future cash flows using discount rates commensurate with the risks involved in the asset group. Long-lived assets committed by management for disposal are accounted for at the lower of amortized cost or fair value less cost to sell.

Sales and Retirements Policies: Gains and losses on the sale or abandonment of oil and gas properties are generally reflected in income. Costs of retired equipment, net of salvage value, are usually charged to accumulated amortization. Unusual retirements are reflected in income.

(Full Cost)

The Company follows the full cost method of accounting for oil and gas property acquisition, exploration, development, and production activities.

Capitalization Policies: All oil and gas property acquisition, exploration, and development costs are capitalized as incurred including internal costs directly attributable to such activities. Capitalized internal costs were $1,200,000 for 2000. Related interest expense incurred during property exploration and development activities is capitalized as a cost of such activity. Net capitalized costs of unproved property and exploration well costs are reclassified as proved property and well costs when related proved reserves are found. Costs to operate and maintain wells and field equipment are expensed as incurred.

Amortization Policies: Except for costs of (1) unevaluated, unproved properties and (2) major development projects in progress, all capitalized oil and gas property costs, net of prior accumulated amortization, are amortized by country using the unit-of-production method based on proved reserves. The amortization base includes estimated future costs to develop proved reserves and estimated future dismantlement, reclamation, and abandonment costs, net of equipment salvage values.

Impairment Policies: Costs not being amortized are periodically assessed for impairment. Any impairment is added to the amortization base.[1] Net capitalized costs of oil and gas properties, less related deferred income taxes are limited, by country, to the sum of (1) future net revenues (using prices and cost rates as of the balance sheet date) from proved reserves and discounted at ten percent per annum, plus (2) costs not being amortized, less (3) related income tax effects.[2] Excess costs are charged to proved property impairment expense.

Sales and Retirements Policies: No gain or loss is recognized on the sale of oil and gas properties unless nonrecognition would significantly alter the relationship between capitalized costs and remaining proved reserves for the affected amortization base. When gain or loss is not recognized, the amortization base is reduced by the amount of sales proceeds.

(For either accounting method)

Revenue Recognition

Revenues from the sale of oil and gas production are recognized when title passes, net of royalties. Natural gas revenues are generally recognized under the entitlements method of accounting for gas imbalances, i.e., monthly sales quantities that do not match the Company's entitled share of joint production. Entitled quantities in excess of sales quantities are recorded as a receivable from joint venture partners. The receivable is carried at the lower of current market price or the market price at the time the imbalance occurred. Sales quantities in excess of entitled quantities are recorded as deferred revenue carried at the gas market price received at the time the imbalance occurred.

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[1]For a foreign country in which the Company has no proved reserves, the impairment may need to be charged to expense. See pages 626 and 627.

[2]The ceiling as described omits a fourth factor, i.e., the lower of cost or fair value of unproved properties being amortized. The fair values of such properties are zero because only the cost of worthless, unproved properties is in the amortization base. Company policy excludes from the amortization base the costs of unevaluated, unproved properties.

The Company's $3 million in long-term receivables under gas balancing arrangements as of December 31, 2000, represent 1.6 bcf of natural gas.[3]

Derivative and Hedging Activities

The Company periodically enters into futures, swaps, forwards and option contracts to manage the risk of future oil and gas price fluctuations. Such contracts may either fix or support oil or gas prices or limit the impact of price fluctuations with respect to the Company's sales of oil and gas.

All derivatives are recognized on the balance sheet at their fair value. On the date the derivative contract is entered into, the Company designates the derivative as a hedge of a forecasted transaction or of the variability of cash flows to be received or paid related to a recognized asset or liability ("cash flow" hedge). The Company does not enter into derivative contracts for trading purposes.

Changes in the fair value of a derivative that is highly effective as, and that is designated and qualifies as, a cash-flow hedge are recorded in other comprehensive income. Unit earnings are effected by the variability of cash flows (e.g., when periodic settlements on a variable-rate asset or liability are recorded in earnings).

The Company formally documents all relationships between hedging instruments and hedged items, as well as its risk-management objective and strategy for undertaking various hedge transactions. This process includes linking all derivatives that are designated as cash-flow hedges to specific firm commitments or forecasted transactions. The Company also formally assesses, both at the hedge's inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair values or cash flows of hedged items. When it is determined that a derivative is not highly effective as a hedge or that it has ceased to be highly effective hedge, the

[3] Disclosure is pursuant to EITF 90-22.

Company discontinues hedge accounting prospectively, as discussed below.

The Company discontinues hedge accounting prospectively when (1) it is determined that the derivative is no longer effective in offsetting changes in cash flows of a hedged item (including firm commitments or forecasted transactions); (2) the derivative expires or is sold, terminated, or exercised; (3) a hedged firm commitment no longer meets the definition of a firm commitment; or (4) management determines that designation of the derivative as a hedge instrument is no longer appropriate.

When hedge accounting is discontinued because the hedged item no longer meets the definition of a firm commitment, the derivative will continue to be carried on the balance sheet at its fair value, and any asset or liability that was recorded pursuant to recognition of the firm commitment will be removed from the balance sheet and recognized as a gain or loss in current-period earnings. When hedge accounting is discontinued because it is probable that a forecasted transaction will not occur, the derivative will continue to be carried on the balance sheet at its fair value, and gains and losses that were accumulated in other comprehensive income will be recognized immediately in earnings. In all other situations in which hedge accounting is discontinued, the derivative will be carried at its fair value on the balance sheet, with changes in its fair value recognized in current-period earnings.

Hedged oil and gas prices used in computing the year-end standardized measure of discounted future net cash flows relating to proved oil and gas reserves reflect the estimated effects of hedging contracts existing at year-end.

Income Taxes

Deferred income taxes are computed using the liability method and are provided on all temporary differences between the financial reporting basis and the tax basis of the Company's assets and liabilities.

Dismantlement, Restoration and Environmental Costs

When a producing property reaches the end of its economic life, surface equipment is dismantled and removed, wells are plugged, and the property surface restored in accordance with environmental laws and regulations (“dismantlement and restoration”). The estimated future dismantlement and restoration are amortized with capitalized development costs by field based on proved developed reserves. The additional accumulated amortization attributable to dismantlement and restoration costs is recognized on the balance sheet as an accrued liability. At December 31, 2000, the Company had accrued $13.65 million for such costs. Anticipated costs for currently proved properties total $24 million, primarily payable in the years 2012 through 2018. Management believes it is reasonably possible that actual future costs may exceed current estimates by as much as $10 million.[4]

Environmental expenditures are expensed or capitalized as appropriate, depending upon their future economic benefit. Expenditures that relate to an existing condition caused by past operations, and that do not have future economic benefit, are expensed. Liabilities for these expenditures are recorded on an undiscounted basis when environmental assessments or clean-ups are probable and the costs can be reasonably estimated. Recoveries of environmental remediation costs from other parties are recorded as assets when their receipt is deemed probable.

Significant Risks and Uncertainties[5]

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make

[4] This illustration reflects the accrued liability as a liability whereas E&P companies typically reflect it in Oil and Gas Property Accumulated DD&A. A proposed SFAS would have the credit shown as a liability. Disclosures for “material” net DR&A costs are implied by SAB Topic 5Y, Question 7 from SAB 92. As discussed in Chapter Twenty, the FASB has issued an Exposure Draft on accounting for asset retirement obligations.

[5] Pursuant to SOP 94-6. This information could appear in other notes to the financial statements.

estimates and assumptions that affect (1) the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the balance sheet date and (2) the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Management believes that it is reasonably possible the following material estimates affecting the financial statements could significantly change in the coming year (1) estimates of proved oil and gas reserves, (2) [for successful efforts] estimates as to the expected future cash flow from proved oil and gas properties, and (3) estimates of future dismantlement and restoration costs.[6]

The Company's business makes it vulnerable to changes in wellhead prices of crude oil and natural gas. Such prices have been volatile in the past and can be expected to be volatile in the future. The Company mitigates some of this vulnerability by entering into oil and gas price derivative contracts as further described in Note 8.

By definition, proved reserves are based on current oil and gas prices. Price declines reduce the estimated quantity of proved reserves and increase annual amortization expense (which is based on proved reserves).

2. Adoption of FAS 133

The company adopted Statement of Financial Accounting Standards No. 133 (FAS 133), *Accounting for Derivative Instruments and Hedging Activities*, on January 1, 2000. In accordance with the transaction provisions of FAS 133, the Company recorded a net-of-tax cumulative-effect-type adjustment of $116,300 in accumulated other comprehensive income to recognize at fair value all derivatives that are designated as cash-flow hedging instruments. Gains and losses on derivatives that were previously deferred as adjustments to the carrying amount of hedged items were not adjusted. The Company expects to reclassify as earnings during the next twelve months $45,000 from the

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[6]Such disclosures are not required if the effect of the reasonably possible change would not be material to the financial statements.

transition adjustment that was recorded in accumulated other comprehensive income.

3. Oil and Gas Properties

(Successful Efforts)

All of the Company's oil and gas properties are located in the United States.

Oil and gas properties, at cost (in thousands):

Proved leasehold costs	$ 31,050
Unproved leasehold costs	9,500
Costs of wells and development	636,520
Drilling in progress	59,630
Capitalized interest	13,400
Total cost of oil and gas properties	$750,100

(Full Cost)

All of the Company's oil and gas properties are located in the United States. Amortization expense was $4.21 per equivalent barrel of production in 2000.[7]

The Company is currently participating in oil and gas exploration and development activities on an offshore block of acreage in the Gulf of Mexico. At December 31, 2000, the determination cannot be made as to the extent of additional proved oil reserves. Consequently, the associated capitalized costs have been excluded in computing amortization of the full cost pool. The Company will begin to amortize these costs when the project is fully evaluated, which is currently estimated to be in mid-2001.

Costs excluded from amortization consist of the following at December 31, 2000 (in thousands): [8]

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[7]Disclosure pursuant to Reg. SX Rule 4-10(c)(7)(i).
[8]Disclosure pursuant to Reg. SX Rule 4-10(c)(7)(ii).

Year Incurred	Acquisition Costs	Exploration Costs	Development Costs	Capitalized Interest	Total
1999	$8,000	$26,700	$ 6,300	$ 800	$41,800
2000	1,500	22,010	5,750	950	30,210
Total	$9,500	$48,710	$12,050	$1,750	$72,010

4. Sales of Oil and Gas Property Interests

In April 2000 the Company sold all interests in the Brittany Rose field in east Texas to Big Oil, Inc., for net proceeds of $60 million in cash, resulting in a gain of $20.5 million. [*For full cost, add*: The gain has not been recognized; capitalized oil and gas property costs have been reduced by the amount of sales proceeds.]

In November 2000, the Company sold a Volume Production Payment to ABC Gas, Inc., for $25 million. The Company is required to deliver two billion cubic feet of gas annually for five years from the KT Ranch field in western Wyoming. The sales proceeds were classified as deferred revenue to be reduced and charged to gas sales revenue as the gas is produced and delivered.

5. Long-Term Debt

At December 31, 2000, long-term debt consisted of the following (in thousands):

Revolving credit agreement	$60,000
Production payments treated as debt	24,000
	84,000
Less amounts due in one year	(7,500)
Long-term debt	$76,500

In 2000, the Company renegotiated its $75 million revolving credit agreement with a syndicate of banks. Indebtedness under the agreement bears interest at 2 percent above the lead bank's prime lending rate (8 percent at December 31, 2000) and is repayable in quarterly installments of $3 million beginning September 30, 2001. This line of credit is collateralized by certain producing oil and gas properties located in Texas and Oklahoma. At December 31, 2000, the unused available line of credit was $15 million.

In October 2000, the Company granted a production payment of $30 million relating to acquisition of certain oil and gas properties. The production payment obligation is payable at ten percent interest per annum from 80 percent of the revenues received through oil and gas production from these properties.

The Company's aggregate long-term debt is estimated to be repayable annually in the following schedule (in thousands):

2001	$ 7,500
2002	16,500
2003	16,000
2004	15,800
2005	15,400
Thereafter	12,800
	$84,000

6. Drilling Advances

During 2000 the Company received drilling advances from joint interest owners which have a remaining balance of $3.78 million at December 31, 2000. These advances will be applied toward the payment of drilling costs to be incurred in 2001.

7. Income Taxes

Not illustrated. Substantially generic. The income tax note would contain:

- *A generic table showing the portions of the income tax provision relating to current income taxes (federal and state) and deferred income taxes (federal and state),*
- *A table reconciling the federal statutory income tax rate to the effective rate, and*
- *A table analyzing the deferred tax liabilities and assets.*

The reconciliation table might include deferred tax liabilities for oil and gas book basis exceeding tax basis due to faster deduction of intangible drilling costs and faster depreciation of tangible equipment. Deferred assets might include Alternative Minimum Tax *credit carryovers, such as for Internal Revenue Code Section 29 tax credits for nonconventional fuel (e.g., coalbed methane production and tight sands gas production).*

8. Financial Instruments and Hedging Activities

In the normal course of business, the Company holds or issues various financial instruments which expose the Company to financial risk associated with market interest rates, currency exchange rates and credit worthiness. Also, the Company's business is affected by commodity price movements. To manage a portion of these risks, the Company purchases and sells various derivative financial instruments and commodity future contracts. Substantially all financial instruments held by the corporation are for purposes other than trading.

Fair Values

The carrying values of most financial instruments are based on historical costs. The carrying values of receivables, payables, marketable securities and short-term obligations approximate their fair value. The estimated fair value of long-term debt (excluding production payments) outstanding as of December 31, 2000 was $68 million. The estimated fair values of marketable securities and debt were based on quoted market prices for the same or similar issues, or the current rates offered to the Company for issues with the same remaining maturities.

Credit Risks

A significant portion of the Company's receivables is from oil and gas companies. Although collection of these receivables could be influenced by economic factors affecting these industries and the countries in which the Company and its customer operate, the risk of significant loss is considered remote.
Substantially all derivatives are either exchange traded or with major financial institutions, and the risk of credit loss is considered remote.

9. Commitments and Contingencies

[Commitments and Contingencies might include several generic matters not unique to petroleum exploration and production and not illustrated herein, e.g., office lease commitments, litigation contingencies, pension fund commitments, employment agreements, and indemnity agreements. Issues arising from petroleum exploration and production might include, for instance, commitments and contingencies as a general partner of oil and gas partnerships, commitments under foreign exploration and development concessions, and industry-related environmental contingencies. Illustrated below is a relatively new type of commitment – an obligation to pay future charges to secure space for moving the Company's natural gas on gas pipeline systems.]

The Company has agreed to pay the following transportation demand charges under contracts with interstate and intrastate gas transmission companies to provide firm and interruptible transportation capacity rights:

Year Ending December 31	Demand Charges (in thousands)
2001	$2,150
2002	1,100
2003	1,000
2004	1,330
2005	1,360
Total	$6,940

10. Proved Property Impairment

[For the illustrated financials, an impairment arose under successful efforts accounting due to the application of FAS 121. For full cost, the company-wide ceiling test required no year 2000 write-down for the Company.]

In 2000 the Company recognized $2 million of proved property impairment expense under the provisions of Statement of Financial Accounting Standards No. 121 (FAS 121). The expense relates primarily to four producing fields with capitalized costs deemed to be impaired under FAS 121 rules, i.e., each field's costs exceeded estimated expected future cash flows. FAS 121 rules require that the impaired capitalized costs of an asset group be reduced to the estimated fair value of the asset group. Expected cash flows and the values were estimated internally using Company methodology and practices for valuing similar properties to be acquired or sold.

Supplemental Information on Oil and Gas Operations (Unaudited)

The following supplemental unaudited information regarding the Company's oil and gas activities is presented pursuant to the disclosure requirements of Statement of Financial Accounting Standards No. 69.[9]

	Successful Efforts	Full Cost
Capitalized Costs Relating to Oil and Gas Producing Activities at December 31, 2000		
Unproved oil and gas properties	$ 69,130	$ 230,000
Proved oil and gas properties	680,970	1,002,060
	750,100	1,232,060
Less accumulated amortization and impairment	(545,700)	(838,240)
Net capitalized costs	$ 204,400	$ 393,820
Costs Incurred in Oil and Gas Producing Activities for the Year Ended December 31, 2000		
Property acquisition costs:		
Proved	$ 15,600	$ 15,600
Unproved	13,500	13,500
Exploration costs	63,290	63,290
Development costs	54,840	54,840
Total costs incurred[10]	$147,230	$147,230

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[9]If Our Oil Company had an investment in an enterprise that was accounted for on the equity method, the Company's share of the investee's net capitalized costs, costs incurred, results of operations for producing activities, reserve quantities, and standardized measure of discounted future net cash flows would be required to be disclosed separately.

[10]The $147,230,000 of cost incurred will only approximate the $151,550,000 expended in cash in 2000 as reported on the consolidated statement of cash flows for full cost.

Results of Operations for Oil and Gas Producing Activities for the Year Ended December 31, 2000[11]

	Successful Efforts	Full Cost
Oil and gas sales	$159,990	$159,990
Production (lifting) costs	(34,520)	(34,520)
Exploration expenses	(49,770)	-
Amortization expense	(15,650)	(31,920)
Proved property impairment	(2,000)	-
	58,050[12]	93,550
Income tax expense	(21,200)	(34,100)
Results of operations	$ 36,850	$ 59,450

[11]These disclosures are presented assuming that Our Oil Company has operations in only one reportable geographic area. If operations are conducted in two or more reportable geographic areas, this information would be required to be reported in total and by geographic area. Further, FAS 69, footnote 7, allows results of operations not to be disclosed as supplemental information when, as is the case here, E&P activities are located in one geographic area and represent substantially all of the Company's operations.

[12]Some companies include a line item for gains and losses on sales of oil and gas properties, but FAS 69 does not specifically require it.

Reserve Information and Related Standardized Measure of Discounted Future Net Cash Flows

The following supplemental unaudited presentation of proved and proved developed reserve quantities and related standardized measure of discounted future net cash flows provides estimates only and does not purport to reflect realizable values or fair market values of the Company's reserves. Volumes reported for proved reserves are based on reasonable estimates. These estimates are consistent with current knowledge of the characteristics and production history of the reserves. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of producing oil and gas properties. Accordingly, significant changes to these estimates are expected as future information becomes available. All of the Company's reserves are located in the United States.

Proved reserves are those estimated reserves of crude oil (including condensate and natural gas liquids) and natural gas that geological and engineering data demonstrate with reasonable certainly to be recoverable in future years from known reservoirs under existing economic and operating conditions. Proved developed reserves are those expected to be recovered through existing wells, equipment, and operating methods.

The standardized measure of discounted future net cash flows relating to proved oil and gas reserves is computed by applying year-end prices of oil and gas (with consideration of price changes only to the extent provided by contractual arrangements) to the estimated future production of proved oil and gas reserves, less estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, less estimated related future income tax expenses (based on year-end statutory tax rates, with consideration of future tax rates already legislated), and assuming continuation of existing economic conditions. Future income tax expenses give effect to permanent differences and tax credits but do not reflect the impact of continuing operations including property acquisitions and exploration. The estimated future cash flows are then discounted using a rate of ten percent a year to reflect the estimated timing of the future cash flows.

Proved Reserves Table:

	Oil (mbbls)	Gas (mmcf)
Proved developed and undeveloped reserves:		
At December 31, 1999	86,080	744,590
Revisions of previous estimates	999	(5,575)
Improved recovery	2,950	-
Purchases of minerals in place	3,300	-
Extensions and discoveries	8,536	25,300
Production	(5,785)	(30,215)
Sales of mineral in place	(11,300)	(23,500)
At December 31, 2000	84,780	710,600
Proved developed reserves:		
At December 31, 1999	62,680	712,200
At December 31, 2000	59,420	675,950

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves at December 31, 2000 (in thousands):[13]

Future cash inflows	$3,181,615
Future production costs	(731,771)
Future development costs	(135,000)
Future income tax expenses	(601,859)
Future net cash flows	1,712,985
10% annual discount for estimated timing of cash flows	(702,617)
Standardized measure of discounted future net cash flows relating to proved oil and gas reserves	$1,010,368

The following reconciles the change in the standardized measure of discounted future net cash flows from proved reserves during 2000 (in thousands):

[13]The reserves and SMOG disclosures are presented based on Our Oil Company having proved reserves only in the United States. If the Company had proved reserves in two or more reportable geographic areas, then proved reserves, changes in proved reserves, and SMOG must be disclosed in total and by geographic area, as illustrated in Chapters Twenty-Eight and Twenty-Nine. Changes in SMOG need not be disclosed by geographic area.

At December 31, 1999	$ 995,945
Increase (decrease) due to:	
Sales of oil and gas produced, net of production costs	(125,470)
Net changes in prices and production costs	(22,960)
Extensions, discoveries, and improved recovery, less related costs	114,837
Development costs incurred during the year which were previously estimated	22,340
Net change in estimated future development costs	(7,708)
Revisions of previous quantity estimates	1,802
Net change from purchases and sales of minerals in place	(83,925)
Accretion of discount	124,294
Net change in income taxes	(7,767)
Other	(1,020)
Net increase	14,423
At December 31, 2000	$1,010,368

APPENDIX 5: ILLUSTRATIVE CHART OF ACCOUNTS

Note: This chart is unusual because it includes accounting needed for either the successful efforts or full cost method. Accounts unique to successful efforts (SE) are noted by an **S** in the left margin; **F** notes accounts unique to full cost (FC). See Figure 4-3 for the Illustrative Condensed Chart of Accounts.

Our Oil Company
Chart of Accounts

100-109	**Cash**		
101	Cash in First National Bank		
102	Cash in First State Bank		
105	Special Deposits		
106	Payroll Account		
107	Petty Cash		
110-119	**Short-Term Investments**		
110	Marketable Securities		
111	Overnight Interest Bearing Accounts		
120 - 129	**Accounts Receivable**		
120	Accounts Receivable—Oil and Gas Sales		
121	Accounts Receivable—Gas Imbalances [if using the "entitlement" method]		
122	Accounts Receivable—Gas Marketing		
123	Accounts Receivable—Joint Interest Billings		
124	Accounts Receivable—Employees		
126	Accounts Receivable—Other Receivables		
127	Accrued Receivables		
		127.001	Oil and Gas Sales
		127.002	Accrued Interest
		127.003	Other
129	Allowance for Doubtful Accounts		
130 -139	**Inventories**		
130	Inventory of Crude Oil [uncommon]		
131	Inventory of Natural Gas Held in Storage		
132	Inventory of Materials and Supplies		
		132.001	Field Yards [detailed by location and type of material]

132.002 Trucking Yards [detailed by location and type of material]
132.003 Warehouse Inventories [detailed by location and type of material)
132.004 Lower of Cost or Market Reserve

140-149 Other Current Assets
140 Prepaid Expenses
141 Current Portion of Long-term Receivables
142 Margin Accounts for Futures Trading
143 Other

210-219 Unproved Property Acquisition Costs*
210 Unproved Property Purchase Suspense [detailed by project]
211 Unproved Leaseholds
211.001 Lease Bonus
211.002 Commissions
211.003 Landman Services and Expenses
211.004 Abstracting Fees
211.005 Capitalized Interest
F 211.006 Delay Rentals
F 211.007 Other Carrying Costs
211.999 Transfers to Proved Mineral Interests
219 Allowance for Impairment of Unproved Properties [detailed by property or by groups of properties or by groups of properties as appropriate]

[Other separate, similar unproved property accounts may be used for other types of economic interests, such as #212 for fee interests, #213 for royalty interests, #214 for overriding royalty interests, #215 for net profits interests, and #216 for volume production payments.]

*Note: The conventional term "unproved property" refers to unevaluated property. Once a property is evaluated as not having proved reserves, the capitalized acquisition costs are either expensed for successful efforts to Account 800, Exploration Expenses, or reclassified for full cost to Account 227, Abandoned and Worthless Property.

	220-226	**Proved Property Acquisition Costs**	
	221	Proved Leaseholds [detailed by lease]	
		[Other separate, similar proved property accounts may be used for other types of economic interests, such as #222 for fee interests, #223 for royalty interests, #224 for overriding royalty interests, and #225 for net profits interests or proved production payments.]	
S	226	Accumulated Amortization of Proved Property Acquisition Costs [detailed by property interest or by geological structure]	
	227-229	**Capitalized Costs of Unsuccessful Efforts**	
F	227	Abandoned and Worthless Properties	
F	228	Impairment of Unproved Properties	
F	229	Unsuccessful Exploration Costs	
	230- 239	**Proved Property Well and Development Costs**	
	231	Intangible Costs of Wells and Development [all with appropriate level of well or field detail]	
F		231.001	Well Drilling and Completion
S		231.001	Successful Exploratory Wells
S		231.002	Successful Development Wells
S		231.003	Development Dry Holes
		231.004	Intangible Capitalizable Workover Costs [rare; workovers are generally repairs which are expensed as production costs]
		231.005	Enhanced Recovery Projects
		231.06	Other Intangibles
		231.07	Accrued DR&A Costs
S	232	Accumulated Amortization of Intangible Costs of Wells and Development	
	233	Tangible Costs of Wells and Development [all with appropriate level of well or field detail]	
F		233.001	Well Drilling and Completion
S		233.001	Successful Exploratory Wells
S		233.002	Successful Development Wells
S		233.003	Development Dry Holes

233.004 Tangible Workover Costs [rare]
233.005 Development Support Equipment and Facilities
233.006 Gas Processing Facilities [may be a separate section]
233.007 Enhanced Recovery Projects
233.008 Other Field Equipment
233.009 Allocated Tangible Cost of Acquired Properties

S 234 Accumulated Amortization of Tangible Costs of Wells and Development

235 Accumulated Amortization for Accrual of Future DR&A Costs [in lieu of Account 410]

F 236 Accumulated Amortization of Oil and Gas Property Acquisition, Exploration, and Development

F 237 Accumulated Impairment of Oil and Gas Property Cost Centers [by country]

F 238 Deferred Losses (Gains) on Sales of Properties

240-249 Work in Progress

240 Work in Progress—Geological and Geophysical Exploration [detailed by project or AFE]

240.001 Geological and Geophysical Contract Work
240.002 Geological and Geophysical Services Other
240.003 Field Party Salaries and Wages
240.004 Field Party Supplies
240.005 Other Field Party Expenses
240.006 Charges for Support Facilities
240.007 Shooting Rights and Damages
240.008 Mapping Expenses
240.009 Equipment Rental
240.010 Other Geological and Geophysical Costs
240.011 Purchased Geological and Geophysical Data
240.012 Overhead
240.015 Transfers to Exploration Expense

241 Work in Progress—Intangible Costs of Wells and Related Development [detailed by AFE]

- 241.001 Drilling Contract
- 241.002 Site Preparation, Roads, Pits
- 241.003 Bits, Reamers, Tools
- 241.004 Labor, Company
- 241.005 Labor, Other
- 241.006 Fuel, Power, Water
- 241.007 Drilling Supplies
- 241.008 Mud and Chemicals
- 241.009 Drill Stem Tests
- 241.010 Coring, Analysis
- 241.011 Electric Surveys, Logs
- 241.012 Geological and Engineering
- 241.013 Cementing
- 241.014 Completion, Fracturing, Acidizing, Perforating
- 241.015 Rig Transportation, Erection, Removal
- 241.016 Environmental and Safety
- 241.017 Other Services
- 241.018 Overhead
- 241.019 Miscellaneous
- 241.025 Capitalized Interest
- 241.028 Transfers to Exploration Expense -- Dry Holes
- 241.029 Transfers to Proved Property Well and Development Costs

243 Work In Progress—Tangible Costs of Wells and Related Development

- 243.030 Tubular Goods
- 243.031 Wellhead and Subsurface Equipment
- 243.032 Pumping Units
- 243.033 Tanks
- 243.034 Separators and Heater-Treaters
- 243.035 Engines and Power Equipment
- 243.036 Flow Lines
- 243.037 Miscellaneous
- 243.038 Installation Costs Surface Equipment

243.045 Capitalized Interest
243.048 Transfers to Exploration Expense -- Dry Holes
243.049 Transfers to Proved Well and Development Costs

244 Work in Progress—Workovers* [usually a production expense]
245 Work in Progress Support Equipment and Facilities*
246 Work in Progress Gas Processing Facilities*
247 Work in Progress Enhanced Recovery Projects*
248 Work in Progress—Other Field Equipment

* Subaccounts are not illustrated.

258-259 General Support Equipment and Facilities

258 Cost of General Support Equipment and Facilities [detailed by facility or unit]
259 Accumulated Depreciation of General Support Equipment and Facilities [detailed by facility or unit]

260-269 Other Plant and Equipment (detailed by asset and location)

261 Autos
262 Office Equipment
263 Buildings
264 Land
268 Other
269 Accumulated Depreciation (detailed by type of equipment and by asset)

270-279 Notes Receivable

270 Notes Receivable—Trade
271 Notes Receivable—Production Payments
272 Notes Receivable—Co-owners
273 Notes Receivable—Officers and Employees
274 Notes Receivable—Other

280-289 Other Assets

280 Pipeline Demand Charges
281 Stock of Subsidiaries
282 Other Stock Investments

283 Cash Surrender Value of Life Insurance
284 Investments in Hedging Instruments
289 Other

290-299 Deferred Charges
290 Deferred Tax Asset
291 Deferred Loss on Hedging of Future Production
292 Deferred Expenses Recoverable Under Foreign Production Sharing Contracts
293 Other Deferred Charges

300-349 Current Liabilities [appropriately detailed in subaccounts]
301 Vouchers Payable
302 Revenue Distributions Payable
303 Lease Bonuses Payable
304 Revenues Held in Suspense
305 Advances from Joint Interest Owners
306 Gas Imbalance Payables [if using "entitlement" method]
307 Accrued Liabilities
310 Short-Term Debt
311 Current Portion of Long-Term Debt
320 Production Taxes Payable
321 *Ad Valorem* Taxes Payable
330 Federal Income Taxes Payable
331 State Income Taxes Payable
332 Payroll Taxes Payable
335 Other Current Liabilities

350-369 Clearing, Apportionment, and Control Accounts
350 District Expenses
351 Region Expenses
352 Support Facility Expenses
360 Revenue Control Account
361 Billing Control Account

400-409 Long-Term Debt
401 Notes Payable
402 Mortgages Payable

403 Bonds Payable
404 Production Payments Payable as Debt
405 Commercial Paper
406 Capitalized Lease Obligations
407 Debt Premium
408 Debt Discount
409 Portion Reclassified as Current

410-419 Other Long-Term Liabilities
410 Accrual for Future Site Restoration [net DR&A] Costs
411 Other Environmental Liabilities
412 Accrued Pension Liability

420 Deferred Income Taxes

430-439 Other Deferred Credits
430 Deferred Revenue for Prepaids
431 Deferred Revenue for Volume Production Payments
432 Deferred Gain (for future commitments on certain property sales)
433 Deferred Gain on Hedging of Future Production

500-599 Stockholders' Equity
500 Preferred Stock
501 Common Stock
505 Additional Paid-In Capital
525 Retained Earnings
530 Dividends

600-699 Revenues [generally net, reduced for royalties due others]
601 Crude Oil Revenues
602 Gas Revenues
603 NGL Revenues
604 Royalty Oil Revenues
605 Royalty Gas Revenues
606 Royalty NGL Revenues
607 Revenues from Net Profit Interests
610 Gain (Loss) on Hedging the Company's Revenues [using futures, options, derivatives, etc.]

615	Gain (Loss) on Trading of futures, Options, and Derivatives [speculative trades]
620	Gains on Property Sales [rare for Full Cost]
625	Interest Income
630	Other Income

701-709 Marketing Expenses

701	Oil Marketing Expenses
702	Gas Marketing Expenses
703	NGL Marketing Expenses

710 Lease Operating Expenses

710 Lease Operating Expenses

710.001	Salaries and Wages
710.002	Employee Benefits
710.003	Contract Pumping Services
710.004	Well Services and Workovers
710.005	Repairs and Maintenance of Surface Equipment
710.006	Fuel, Water, and Lubrication
710.007	Supplies
710.008	Auto and Truck Expenses
710.009	Supervision
710.010	*Ad Valorem* Taxes
710.011	Production Taxes and Severance Taxes
710.012	Other Taxes
710.013	Compressor Rentals
710.014	Insurance
710.015	Salt Water Disposal
710.016	Treating Expenses
710.017	Environment and Safety
710.018	Overhead
710.019	Shut-in and Minimum Royalties
710.020	Other Royalties (where appropriate)
710.021	Pressure Maintenance
710.022	Other

	725-749	**DD&A**
F	725	Depreciation, Depletion, and Amortization
S		726 Amortization of Proved Property Acquisition Costs
S		732 Amortization of Intangible Costs of Wells and Development
S		734 Amortization of Tangible Costs of Wells and Development
	735	Amortization for Accrual of Future DR&A Costs
	739	Depreciation of General Support Equipment and Facilities
	749	Depreciation of Other Plant and Equipment
	760-761	**Loss on Impairment of Long-Lived Assets**
	760	Loss on Impairment of Long-Lived Assets
F	761	Provision for Impairment of Oil and Gas Assets
S	**800-899**	**Exploration Expenses**
S	801	Geological and Geophysical Expenses
S		801.001 Geological and Geophysical Contract Work
S		801.002 Geological and Geophysical Services Other
S		801.003 Field Party Salaries and Wages
S		801.004 Field Party Supplies
S		801.005 Other Field Party Expenses
S		801.007 Shooting Rights and Damages
S		801.008 Mapping Expenses
S		801.009 Equipment Rental
S		801.010 Other Geological and Geophysical Costs
S		801.011 Purchased Geological and Geophysical Data
S		801.012 Overhead
S	802	Carrying and Retaining Undeveloped Properties
S		802.001 Rentals [alias Delay Rentals]
S		802.002 *Ad Valorem* Taxes
S		802.003 Title Defense
S		802.004 Record Maintenance
S	803	Test-Well Contributions

S		803.001	Dry-Hole Costs
S		803.002	Bottom-Hole Costs
S	804	Unsuccessful Exploratory Wells [i.e., Dry Holes]	
S		804.001	Intangibles
S		804.002	Tangibles
S	805	Unsuccessful Exploratory Stratigraphic Test Wells	
S		805.001	Intangibles
S		805.002	Tangibles
S	806	Impairment, Amortization and Abandonment of Unproved Properties	

900-919 General and Administrative Expenses

901 Officers' Salaries
902 Other Salaries
903 Employee Benefits
904 Rent
905 Office Supplies
906 Utilities
907 Dues and Subscriptions
908 Travel and Entertainment
909 Legal and Auditing
910 Insurance
911 Taxes Other Than Income
912 Contributions
918 Miscellaneous G&A Expense
919 Operator's Overhead Recovery

920-929 Interest Expense

920 Interest on Debts
921 Other Interest
922 Gain (Loss) on Hedging of Interest Expense
923 Transfer for Interest Capitalized

930 Losses on Sales of Property

931 Provisions for Restructuring

940-949 Income Tax Provision

940	Current Federal Income Taxes
941	Current State and Local Income Taxes
942	Current Foreign Income Taxes
945	Deferred Federal Income Taxes
946	Deferred State and Local Income Taxes
947	Deferred Foreign Income Taxes
960	**Extraordinary Items**

Note: Revenues, taxes, and lease activities must often be tracked or summarized by state. The American Petroleum Institute (API) has the following standardized numerical codes to facilitate such tracking:

API CODE
FOR U.S. STATES AND OFFSHORE FEDERAL WATERS

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APPENDIX 6: MMS LEASING FORM
(March 1986 to present)

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UNITED STATES
DEPARTMENT OF THE INTERIOR
MINERALS MANAGEMENT SERVICE

OIL AND GAS LEASE OF SUBMERGED LANDS UNDER THE OUTER CONTINENTAL SHELF LANDS ACT1

This form does not constitute an information collection as defined by U.S.C. 3502 and therefore does not require approval by the Office of Management and Budget.</td><td>Office</td><td>Serial number</td></tr>
<tr><td>Cash bonus</td><td>Rental rate per acre, hectare
or fraction thereof</td></tr>
<tr><td>Minimum royalty rate per acre, hectare or fraction thereof</td><td>Royalty rate

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This lease is effective as of (hereinafter called the 'Effective Date") and shall continue for an initial period of **years (hereinafter called the "Initial Period")** by and between the United States of America (hereinafter called the "Lessor"), by the Minerals Management Service, its authorized officer, and (hereinafter called the "Lessee"). In consideration of any cash payment heretofore made by the Lessee to the Lessor and in consideration of the promises, terms, conditions, and covenants, contained herein, including the Stipulation(s) numbered attached hereto, the Lessee and Lessor agree as follows:

Sec. 1. Statutes and Regulations. This lease is issued pursuant to the Outer Continental Shelf Lands Act of August 7, 1953, 67 Stat. 462; 43 U.S.C. 1331 et seq., as amended (92 Stat. 629), (hereinafter called the "Act"). The lease is issued subject to the Act; all regulations issued pursuant to the Act and in existence upon the Effective Date of this lease; all regulations issued pursuant to the statute in the future which provide for the prevention of waste and conservation of the natural resources of the Outer Continental Shelf and the protection of correlative rights therein; and all other applicable statutes and regulations.

Sec. 2. Rights of Lessee. The Lessor hereby grants and leases to the Lessee the exclusive right and privilege to drill for, develop, and produce oil and gas resources, except helium gas, in the submerged lands of the Outer Continental Shelf containing approximately acres or hectares (hereinafter referred to as the "leased area"), described as follows:

These rights include:

(a) the nonexclusive right to conduct within the leased area geological and geophysical explorations in accordance with applicable regulations;

(b) the nonexclusive right to drill water wells within the leased area, unless the water is part of geopressured-geothermal and associated resources, and to use the water produced therefrom for operations pursuant to the Act free of cost, on the condition that the drilling is conducted in accordance with procedures approved by the Director of the Minerals Management Service or the Director's delegate (hereinafter called the "Director"); and

(c) the right to construct or erect and to maintain within the leased area artificial islands, installations, and other devices permanently or temporarily attached to the seabed and other works and structures necessary to the full enjoyment of the lease, subject of compliance with applicable laws and regulations .

Sec. 3. <u>Term</u>. This lease shall continue from the Effective Date of the lease for the Initial Period and so long thereafter as oil or gas is produced from the leased area in paying quantities, or drilling or well reworking operations, as approved by the Lessor, are conducted thereon, or as otherwise provided by regulation.

Sec. 4. <u>Rentals</u>. The Lessee shall pay the Lessor, on or before the first day of each lease year which commences prior to a discovery in paying quantities of oil or gas on the leased area, a rental as shown on the face hereof.

Sec. 5. <u>Minimum Royalty</u>. The Lessee shall pay the Lessor, at the expiration of each lease year which commences after a discovery of oil and gas in paying quantities, a minimum royalty as shown on the face hereof or, if there is production, the difference between the actual royalty required to be paid with respect to such lease year and the prescribed minimum royalty if the actual royalty paid is less than the minimum royalty.

Sec. 6. <u>Royalty on Production</u>.

(a) The Lessee shall pay a fixed royalty as shown on the face hereof in amount or value of production saved, removed, or sold from the leased area. Gas (except helium) and oil of all kinds are subject to royalty. Any Lessee is liable for royalty payments on oil or gas lost or wasted from a lease site when such loss or waste is due to negligence on the part of the operator of the lease, or due to the failure to comply with any rule or regulation, order, or citation issued under the Federal Oil and Gas Royalty Management. Act of 1982 or the Act. The Lessor shall determine whether production royalty shall be paid in amount or value.

(b) The value of production for purposes of computing royalty on production from this lease shall never be less than the fair market value of the production. The value of production shall be the estimated reasonable value of the production as determined by the Lessor, due consideration being given to the highest price paid for a part or for a majority of production of like quality in the same field or area, to the price received by the Lessee, to posted prices, to regulated prices, and to other relevant matters. Except when the Lessor, in its discretion, determines not to consider special pricing relief from otherwise applicable Federal regulatory requirements, the value of production for the purposes of computing royalty shall not be deemed to be less than the gross proceeds accruing to the Lessee from the sale thereof. In the absence of good reason to the contrary, value computed on the basis of the highest price paid or offered at the time of production in a fair and open market for the major portion of like-quality products produced and sold from the field or area where the leased area is situated will be considered to be a reasonable value.

(c) When paid in value, royalties on production shall be due and payable monthly on the last day of the month next following the month in which the production is obtained, unless the Lessor designates a later time. When paid in amount, such royalties shall be delivered at pipeline connections or in tanks provided by the Lessee. Such deliveries shall be made at reasonable times and intervals and, at the Lessor's option, shall be effected either (i) on or immediately adjacent to the leased area, without cost to the Lessor, or (ii) at a more convenient point closer to shore or on shore, in which event the Lessee shall be entitled to reimbursement for the reasonable cost of transporting the royalty substance to such delivery point.

Sec. 7. <u>Payments.</u> The Lessee shall make all payments (rentals, royalties, and any other payments required by this lease) to the Lessor by electronic transfer of funds, check, draft on a solvent bank, or money order unless otherwise provided by regulations or by direction of the Lessor. Rentals, royalties, and any other payments required by this lease shall be made payable to the Minerals Management Service and tendered to the Director. Determinations made by the Lessor as to the amount of payment due shall be presumed to be correct and paid as due.

Sec. 8. Bonds. The Lessee shall maintain at all times the bond(s) required by regulation prior to the issuance of the lease and shall furnish such additional security as may be required by the Lessor if, after operations have begun, the Lessor deems such additional security to be necessary.

Sec. 9. Plans. The Lessee shall conduct all operations on the leased area in accordance with approved exploration plans and approved development and production plans as are required by regulations. The Lessee may depart from an approved plan only as provided by applicable regulations.

Sec. 10. Performance. The Lessee shall comply with all regulations and Orders. After due notice in writing, the Lessee shall drill such wells and produce at such rates as the Lessor may require in order that the leased area or any part thereof may be properly and timely developed and produced in accordance with sound operating principles.

Sec. 11. Directional Drilling. A directional well drilled under the leased area from a surface location on nearby land not covered by this lease shall be deemed to have the same effect for all purposes of the lease as a well drilled from a surface location on the leased area. In those circumstances, drilling shall be considered to have been commenced on the leased area when drilling is commenced on the nearby land for the purpose of directionally drilling under the leased area, and production of oil or gas from the leased area through any directional well surfaced on nearby land or drilling or reworking of any such directional well shall be considered production or drilling or reworking operations on the leased area for all purposes of the lease. Nothing contained in this Section shall be construed as granting to the Lessee any interest, license, easement, or other right in any nearby land.

Sec. 12. Safety Requirements. The Lessee shall:

(a) maintain all places of employment within the leased area in compliance with occupational safety and health standards and, in addition, free from recognized hazards to employees of the Lessee or of any contractor or subcontractor operating within the lease area;

(b) maintain all operations within the leased area in compliance with regulations or orders intended to protect persons, property, and the environment on the Outer Continental Shelf; and

(c) allow prompt access, at the site of any operation subject to safety regulations, to any authorized Federal inspector and shall provide any documents and records which are pertinent to occupational or public health, safety, or environmental protection as may be requested.

Sec. 13. Suspension and Cancellation.

(a) The Lessor may suspend or cancel this lease pursuant to section 5 of the Act, and compensation shall be paid when provided by the Act.

(b) The Lessor may, upon recommendation of the Secretary of Defense, during a state of war or national emergency declared by Congress or the President of the United States, suspend operations under the lease, as provided in section 12(c) of the Act, and just compensation shall be paid to the Lessee for such suspension.

Sec. 14. Indemnification. The Lessee shall indemnify the Lessor for, and hold it harmless from, any claim, including claims for loss or damage to property or injury to persons caused by or resulting from any operation on the leased area conducted by or on behalf of the Lessee. However, the Lessee shall not be held responsible to the Lessor under this section for any loss, damage, or injury caused by or resulting from:

(a) negligence of the Lessor other than the commission or omission of a discretionary function or duty on the part of a Federal Agency whether or not the discretion involved is abused; or

(b) the Lessee's compliance with an order or directive of the Lessor against which an administrative appeal by the Lessee is filed before the cause of action for the claim arises and is pursued diligently thereafter.

Sec. 15. Disposition of Production.

(a) As provided in section 27(a)(2) of the Act, the Lessor shall have the right to purchase not more than 16 2/3 percent by volume of the oil and gas produced pursuant to the lease at the regulated price or, if no regulated price applies, at the fair market value at the wellhead of the oil and gas saved, removed, or sold, except that any oil or gas obtained by the Lessor as royalty or net profit share shall be credited against the amount that may be purchased under this subsection.

(b) Pursuant to section 27(b) and (c) of the Act, the Lessor may offer and sell certain oil and gas obtained or purchased pursuant to a lease. As provided in section 27(d) of the Act, the Lessee shall take any Federal oil or gas for which no acceptable bids are received, as determined by the Lessor, and which is not transferred to a Federal Agency pursuant to section 27(a)(3) of the Act, and shall pay to the Lessor a cash amount equal to the regulated price or, if no regulated price applies, the fair market value of the oil or gas so obtained.

(c) As provided in Section 8(b)(7) of the Act, the Lessee shall offer 20 percent of the crude oil, condensate, and natural gas liquids produced on the lease, at market value and point of delivery as provided by regulations applicable to Federal royalty oil, to small or independent refiners as defined in the Emergency Petroleum Allocation Act of 1973.

(d) In time of war or when the President of the United States shall so prescribe, the Lessor shall have the right of first refusal to purchase at the market price all or any portion of the oil or gas produced from the leased area, as provided in section 12(b) of the Act.

Sec. 16. Unitization, Pooling, and Drilling Agreements. Within such time as the Lessor may prescribe, the Lessee shall subscribe to and operate under a unit, pooling, or drilling agreement embracing all or part of the lands subject to this lease as the Lessor may determine to be appropriate or necessary. Where any provision of a unit, pooling, or drilling agreement, approved by the Lessor, is inconsistent with a provision of this lease, the provision of the agreement shall govern.

Sec. 17. Equal Opportunity Clause. During the performance of this lease, the Lessee shall fully comply with paragraphs (I) through (7) of section 202 of Executive Order 1 1246, as amended (reprinted in 41 CFR t50-1 .4(a)), and the implementing regulations which are for the purpose of preventing employment discrimination against persons on the basis of race, color, religion, sex, or national origin. Paragraphs (I) through (7) of section 202 of Executive Order 11246, as amended, are incorporated in this lease by reference.

Sec. 18. Certification of Nonsegregated Facilities. By entering into this lease, the Lessee certifies, as specified in 41 CFR 60-1.8, that it does not and will not maintain or provide for its employees any segregated facilities at any of its establishments and that it does not and will not permit its employees to perform their services at any location under its control where segregated facilities are maintained. As used in this certification, the term "segregated facilities" means, but is not limited to, any waiting rooms, work areas, restrooms and washrooms, restaurants and other eating areas, timeclocks, locker rooms and other storage or dressing areas, parking lots, drinking fountains, recreation or entertainment areas, transportation, and housing facilities provided for employees which are segregated by explicit directive or are in fact segregated on the basis of race, color, religion, or national origin, because of habit, local custom, or otherwise. The Lessee further agrees that it will obtain identical certifications from proposed contractors and subcontractors prior to award of contracts or subcontracts unless they are exempt under 41 CFR 60-1.5.

Sec. 19. Reservations to Lessor. All rights in the leased area not expressly granted to the Lessee by the Act, the regulations, or this lease are hereby reserved to the Lessor. Without limiting the generality of the foregoing, reserved rights included:

(a) the right to authorize geological and geophysical exploration in the lease area which does not unreasonably interfere with or endanger actual operations under the lease, and the right to grant such easements or rights-of-way upon, through, or in the leased area as may be necessary or appropriate to the working of other lands or to the treatment and shipment of products thereof by or under authority of the Lessor;

(b) the right to grant leases for any minerals other than oil and gas within the leased area, except that operations under such leases shall not unreasonably interfere with or endanger operations under this lease;

(c) the right, as provided in section 12(d) of the Act, to restrict operations in the leased area or any part thereof which may be designated by the Secretary of Defense, with approval of the President, as being within an area needed for national defense and, so long as such designation remains in effect, no operations may be conducted on the surface of the leased area or the part thereof included within the designation except with the concurrence of the Secretary of Defense. If operations or production under this lease within any designated area are suspended pursuant to this paragraph, any payments of rentals and royalty prescribed by this lease likewise shall be suspended during such period of suspension of operations and production, the term of this lease shall be extended by adding thereto any such suspension period, and the Lessor shall be liable to the Lessee for such compensation as is required to be paid under the Constitution of the United States.

Sec. 20. Transfer of Lease. The Lessee shall file for approval with the appropriate field office of the Minerals Management Service any instrument of assignment or other transfer of this lease, or any interest therein, in accordance with applicable regulations.

Sec. 21. Surrender of Lease. The Lessee may surrender this entire lease or any officially designated subdivision of the leased area by filing with the appropriate field office of the Minerals Management Service a written relinquishment, in triplicate, which shall be effective as of the date of filing. No surrender of this lease or of any portion of the leased area shall relieve the Lessee or its surety of the obligation to pay all accrued rentals, royalties, and other financial obligations or to abandon all wells on the area to be surrendered in a manner satisfactory to the Director.

Sec. 22. Removal of Property on Termination of Lease. Within a period of 1 year after termination of this lease in whole or in part, the Lessee shall remove all devices, works, and structures from the premises no longer subject to the lease in accordance with applicable regulations and Orders of the Director. However, the Lessee may, with the approval of the Director, continue to maintain devices, works, and structures on the leased area for drilling or producing on other leases.

Sec. 23. Remedies in Case of Default.

(a) Whenever the Lessee fails to comply with any of the provisions of the Act, the regulations issued pursuant to the Act, or the terms of this lease, the lease shall be subject to cancellation in accordance with the provisions of section 5(c) and (d) of the Act and the Lessor may exercise any other remedies which the Lessor may have, including the penalty provisions of section 24 of the Act. Furthermore, pursuant to section 8(o) of the Act, the Lessor may cancel the lease if it is obtained by fraud or misrepresentation.

(b) Nonenforcement by the Lessor of a remedy for any particular violation of the provisions of the Act, the regulations issued pursuant to the Act, or the terms of this lease shall not prevent the cancellation of this lease or the exercise of any other remedies under paragraph (a) of this section for any other violation occurring at any other time.

Sec. 24. Unlawful Interest. No member of, or Delegate to, Congress, or Resident Commissioner, after election or appointment, or either before or after they have qualified and during their continuance in office, and no officer, agent, or employee of the Department of the Interior, except as provided in 43 CFR Part 20, shall be admitted to any share or part in this lease or derive any benefit that may arise therefrom. The provisions of Section 3741 of the Revised Statutes, as amended, 41 U.S.C. 22, and the Act of June 25, 1948, 62 Stat. 702, as amended, 18 U.S.C. 431-433, relating to contracts made or entered into, or accepted by or on behalf of the United States, form a part of this lease insofar as they may be applicable.

	THE UNITED STATES OF AMERICA, Lessor
(Lessee)	
(Signature of Authorized Officer)	(Signature of Authorized Officer)
(Name of Signatory)	(Name of Signatory)
(Title)	(Title)
(Date)	(Date)
(Address of Lessee)	

If this lease is executed by a corporation, it must bear the corporate seal.

APPENDIX 7: TEXAS OFFSHORE LEASING FORM

Lease Form
Revised 10/99[1]
G - III/IV

SAMPLE
OIL AND GAS LEASE
NO. M-_________

WHEREAS, pursuant to the Texas Natural Resources Code Chapters 32, 33, 51, and Chapter 52, Subchapters A-D and H, (said Code being hereinafter referred to as N.R.C.), and subject to all rules and regulations promulgated by the Commissioner of the General Land Office and/or the School Land Board pursuant thereto, and all other applicable statutes and amendments to said N.R.C., the following area, to-wit:

was, after being duly advertised, offered for lease on the **4th** day of **April, 2000**, at 10:00 o'clock a.m., by the Commissioner of the General Land Office of the State of Texas and the School Land Board of the State of Texas, for the sole and only purpose of prospecting and drilling for, and producing oil and/or gas that may be found and produced from the above described area; and

WHEREAS, after all bids and remittances which were received up to said time have been duly considered by the Commissioner of the General Land Office and the School Land Board at a regular meeting thereof in the General Land Office, on the **4th** day of **April, 2000**, hereinafter the "effective date" and it was found and determined that **________________** whose address is **__________________, ____________** had offered the highest and best bid for a lease of the area above described and is, therefore, entitled to receive a lease thereon:

NOW, THEREFORE, I, David Dewhurst, Commissioner of the General Land Office of the State of Texas, hereinafter sometimes referred to as "Lessor," whose address is Austin, Texas, by virtue of the authority vested in me and in consideration of the payment by the hereinafter designated Lessee, the sum of **____________________** Dollars (**$____________**), receipt of which is hereby acknowledged and of the royalties, covenants, stipulations and conditions contained and hereby agreed to be paid, observed and performed by Lessee, do hereby demise, grant, lease and let unto the above mentioned bidder the exclusive right to prospect for, produce and take oil and/or gas from the aforesaid area upon the following terms and conditions, to-wit:

1. RESERVATION: There is hereby excepted and reserved to Lessor the full use of the property covered hereby and all rights with respect to the surface and subsurface thereof for any and all purposes except those granted and to the extent herein granted to Lessee, together with the rights of ingress and egress and use of said lands by Lessor and its mineral lessees, for purposes of exploring for and producing the minerals which are not covered, or which may not be covered in the future, under the terms of this lease, but which may be located within the surface boundaries of the leased area. All of the rights in and to the leased premises retained by Lessor and all of the rights in and to the leased premises granted to Lessee herein shall be exercised in such a manner that neither shall unduly interfere with the operations of the other.

[1] For the most recent version of the form, go to the Texas General Land Office's web site at www.glo.state.tx.us where the Office's Energy Resources section posts a recent form for upcoming lease sales.

2. TERM: Subject to the other provisions hereof, this lease shall be for a term of **five (5)** years from the effective date hereof (herein called "primary term") and as long thereafter as oil or gas is produced in paying quantities from said area.

3. DELAY RENTALS: If no well be commenced on the land hereby leased on or before the anniversary date of this lease, this lease shall terminate as to both parties unless the Lessee on or before said date shall pay or tender to the Commissioner of the General Land Office of the State of Texas at Austin, Texas, the sum of **Ten** Dollars (**$10.00**), **per acre**, which shall operate as rental and cover the privilege of deferring the commencement of a well for twelve (12) months from said date. In like manner and upon like payments or tenders the commencement of a well may be further deferred for like periods of the same number of months successively during the primary term hereof.

4. PRODUCTION ROYALTIES: Subject to the provisions for royalty reductions set out in subparagraph (E) of this paragraph 4, upon production of oil and/or gas, the Lessee agrees to pay or cause to be paid to the Commissioner of the General Land Office in Austin, Texas, for the use and benefit of the State of Texas, during the term hereof:

(A) OIL: As a royalty on oil, which is defined as including all hydrocarbons produced in a liquid form at the mouth of the well and also all condensate, distillate, and other liquid hydrocarbons recovered from oil or gas run through a separator or other equipment, as hereinafter provided, <u>1/4</u> part of the gross production or the market value thereof, at the option of the Lessor, such value to be determined by 1) the highest posted price, plus premium, if any, offered or paid for oil, condensate, distillate, or other liquid hydrocarbons, respectively, of a like type and gravity in the general area where produced and when run, or 2) the highest market price thereof offered or paid in the general area where produced and when run, or 3) the gross proceeds of the sale thereof, whichever is the greater. Lessee agrees that before any gas produced from the land hereby leased is sold, used or processed in a plant, it will be run free of cost to Lessor through an adequate oil and gas separator of conventional type or other equipment at least as efficient to the end that all liquid hydrocarbons recoverable from the gas by such means will be recovered. Upon written consent of Lessor, the requirement that such gas be run through such a separator or other equipment may be waived upon such terms and conditions as prescribed by Lessor.

(B) NON-PROCESSED GAS: As a royalty on any gas (including flared gas), which is defined as all hydrocarbons and gaseous substances not defined as oil in subparagraph (A) above, produced from any well on said land (except as provided herein with respect to gas processed in a plant for the extraction of gasoline, liquid hydrocarbons or other products) <u>1/4</u> part of the gross production or the market value thereof, at the option of the Lessor, such value to be based on the highest market price paid or offered for gas of comparable quality in the general area where produced and when run, or the gross price paid or offered to the producer, whichever is greater provided that the maximum pressure base in measuring the gas under this lease contract shall not at any time exceed 14.65 pounds per square inch absolute, and the standard base temperature shall be sixty (60) degrees Fahrenheit, correction to be made for pressure according to Boyle's Law, and for specific gravity according to test made by the Balance Method or by the most approved method of testing being used by the industry at the time of testing.

(C) PROCESSED GAS: As a royalty on any gas processed in a gasoline plant or other plant for the recovery of gasoline or other liquid hydrocarbons, <u>**1/4**</u> part of the residue gas and the liquid hydrocarbons extracted or the market value thereof, at the option of the Lessor. All royalties due herein shall be based on one hundred percent

(100%) of the total plant production of residue gas attributable to gas produced from this lease, and on fifty percent (50%) or that percent accruing to Lessee, whichever is the greater, of the total plant production of liquid hydrocarbons, attributable to the gas produced from this lease; provided that if liquid hydrocarbons are recovered from gas processed in a plant in which Lessee (or its parent, subsidiary or affiliate) owns an interest, then the percentage applicable to liquid hydrocarbons shall be fifty percent (50%) or the highest percent accruing to a third party processing gas through such plant under a processing agreement negotiated at arms' length (or if there is no such third party, the highest percent then being specified in processing agreements or contracts in the industry), whichever is the greater. The respective royalties on residue gas and on liquid hydrocarbons shall be determined by 1) the highest market price paid or offered for any gas (or liquid hydrocarbons) of comparable quality in the general area or 2) the gross price paid or offered for such residue gas (or the weighted average gross selling price for the respective grades of liquid hydrocarbons), whichever is the greater. In no event, however, shall the royalties payable under this paragraph be less than the royalties which would have been due had the gas not been processed.

(**D) OTHER PRODUCTS:** As a royalty on carbon black, sulphur or any other products produced or manufactured from gas (excepting liquid hydrocarbons) whether said gas be "casinghead," "dry" or any other gas, by fractionating, burning or any other processing, **1/4** part of gross production of such products, or the market value thereof, at the option of Lessor, such market value to be determined as follows:

(1) On the basis of the highest market price of each product, during the same month in which such product is produced, or

(2) On the basis of the average gross sale price of each product for the same month in which such products are produced; whichever is the greater.

(E) VARIABLE ROYALTY: (i) Subject to the other provisions of this lease, it is hereby provided that in the event production in paying quantities is established pursuant to the terms of this lease and such production is brought on line and sales thereof are commenced within twenty-four (24) months of the effective date hereof, the royalty rate provided herein shall be reduced to 20%, and shall apply to each subsequent well drilled and produced on the land covered by this lease. Provided that, if during such twenty-four (24) month term during which Lessee may earn a reduced royalty rate of 20% as herein provided, Lessee should drill in good faith and complete the first well as a dry hole on the land covered by this lease, Lessee may receive a six (6) month extension of the term in which to earn a reduced royalty rate by giving notice to the Commissioner of the General Land Office, commencing drilling operations on an additional well prior to the expiration of such six (6) month period and prosecuting diligently and in good faith the drilling of such additional well and completing same so that production in paying quantities is established and so that such production is brought on line and sales thereof are commenced prior to the expiration of such six (6) month extension period.

(ii) In the event production in paying quantities is established pursuant to the terms of this lease and such production is brought on line and sales thereof are commenced after the expiration of twenty-four (24) months from the effective date hereof but prior to the expiration of forty-eight (48) months from the effective date hereof, the royalty rate provided herein shall be reduced to 22.5% and shall apply to each subsequent well drilled and produced on the land covered by this lease. Provided that, if during such twenty-four (24) month term during which Lessee may earn a reduced royalty rate of 22.5% as herein provided, Lessee should drill in good faith and complete the first well as a dry hole on the land covered by this lease, Lessee may receive a six (6) month extension of the term in which to earn a reduced royalty rate by giving notice to the Commissioner of the General

Land Office, commencing drilling operations on an additional well prior to the expiration of such six (6) month period and prosecuting diligently and in good faith the drilling of such additional well and completing same so that production in paying quantities is established and so that such production is brought on line and sales thereof are commenced prior to the expiration of such six (6) month extension period.

(F) NO DEDUCTIONS: Lessee agrees that all royalties accruing to Lessor under this lease shall be without deduction for the cost of producing, transporting, and otherwise making the oil, gas and other products produced hereunder ready for sale or use.

(G) ROYALTY IN KIND: Notwithstanding anything contained herein to the contrary, Lessor may, at its option, upon not less than 60 days notice to Lessee, require at any time or from time to time that payment of all or any royalties accruing to Lessor under this lease be made in kind without deduction for the cost of producing, gathering, storing, separating, treating, dehydrating, compressing, processing, transporting and otherwise making the oil, gas and other products produced hereunder ready for sale or use. Lessor's right to take its royalty in kind shall not diminish or negate Lessor's rights or Lessee's obligations, whether express or implied, under this lease.

(H) PLANT FUEL AND RECYCLED GAS: No royalty shall be payable on any gas as may represent this lease's proportionate share of any fuel used to process gas produced hereunder in any processing plant. Notwithstanding anything contained herein to the contrary, and subject to the consent in writing of the Commissioner of the General Land Office, Lessee may recycle gas for gas lift purposes on the leased premises after the liquid hydrocarbons contained in the gas have been removed, and no royalties shall be payable on the gas so recycled until such time as the same may thereafter be produced and sold or used by Lessee in such manner as to entitle Lessor to a royalty thereon under the royalty provisions of this lease.

(I) MINIMUM ROYALTY: During any year after the expiration of the primary term of this lease, if this lease is maintained by production, the royalties paid to Lessor in no event shall be less than an amount equal to the total annual delay rental herein provided; otherwise, there shall be due and payable on or before the last day of the month succeeding the anniversary date of this lease a sum equal to the total annual rental less the amount of royalties paid during the preceding year.

(J) MARGINAL PRODUCTION ROYALTY: Upon Lessee's written application, the School Land Board may reduce the royalty rate set out in this paragraph and/or the minimum royalty set out in subparagraph 4 (I) to extend the economic life of this lease and encourage recovery of oil or gas that might otherwise remain unrecovered. Any such royalty reduction must conform to the requirements of any School Land Board Administrative rules on this subject. Royalty may not be reduced below the applicable statutory minimum.

5. ROYALTY PAYMENTS AND REPORTS: All royalties not taken in kind shall be paid to the Commissioner of the General Land Office at Austin, Texas, in the following manner:

Payment of royalty on production of oil and gas shall be as provided in the rules set forth in the Texas Register. Rules currently provide that royalty on oil is due and must be received in the General Land Office on or before the 5th day of the second month succeeding the month of production, and royalty on gas is due and must be received in the General Land Office on or before the 15th day of the second month succeeding the month of production, accompanied by the affidavit of the owner, manager or other authorized agent, completed in the form and manner prescribed by the General Land

Office and showing the gross amount and disposition of all oil and gas produced and the market value of the oil and gas, together with a copy of all documents, records or reports confirming the gross production, disposition and market value including gas meter readings, pipeline receipts, gas line receipts and other checks or memoranda of amount produced and put into pipelines, tanks, or pools and gas lines or gas storage, and any other reports or records which the General Land Office may require to verify the gross production, disposition and market value. In all cases the authority of a manager or agent to act for the Lessee herein must be filed in the General Land Office. Each royalty payment shall be accompanied by a check stub, schedule, summary or other remittance advice showing by the assigned General Land Office lease number the amount of royalty being paid on each lease. If Lessee pays his royalty on or before thirty (30) days after the royalty payment was due, then Lessee owes a penalty of 5% on the royalty or $25.00, whichever is greater. A royalty payment which is over thirty (30) days late shall accrue a penalty of 10% of the royalty due or $25.00 whichever is greater. In addition to a penalty, royalties shall accrue interest at a rate of 12% per year; such interest will begin accruing when the royalty is sixty (60) days overdue. Affidavits and supporting documents which are not filed when due shall incur a penalty in an amount set by the General Land Office administrative rule which is effective on the date when the affidavits or supporting documents were due. The Lessee shall bear all responsibility for paying or causing royalties to be paid as prescribed by the due date provided herein. Payment of the delinquency penalty shall in no way operate to prohibit the State's right of forfeiture as provided by law nor act to postpone the date on which royalties were originally due. The above penalty provisions shall not apply in cases of title dispute as to the State's portion of the royalty or to that portion of the royalty in dispute as to fair market value.

6. (A) RESERVES, CONTRACTS AND OTHER RECORDS: Lessee shall annually furnish the Commissioner of the General Land Office with its best possible estimate of oil and gas reserves underlying this lease or allocable to this lease and shall furnish said Commissioner with copies of all contracts under which gas is sold or processed and all subsequent agreements and amendments to such contracts within thirty (30) days after entering into or making such contracts, agreements or amendments. Such contracts and agreements when received by the General Land Office shall be held in confidence by the General Land Office unless otherwise authorized by Lessee. All other contracts and records pertaining to the production, transportation, sale and marketing of the oil and gas produced on said premises, including the books and accounts, receipts and discharges of all wells, tanks, pools, meters, and pipelines shall at all times be subject to inspection and examination by the Commissioner of the General Land Office, the Attorney General, the Governor, or the representative of any of them.

(B) DRILLING RECORDS: Written notice of all operations on this lease shall be submitted to the Commissioner of the General Land Office by Lessee or operator five (5) days before spud date, workover, re-entry, temporary abandonment or plug and abandonment of any well or wells. Such written notice to the General Land Office shall include copies of Railroad Commission forms for application to drill. Copies of well tests, completion reports and plugging reports shall be supplied to the General Land Office at the time they are filed with the Texas Railroad Commission. Lessee shall supply the General Land Office with any records, memoranda, accounts, reports, cuttings and cores, or other information relative to the operation of the above-described premises, which may be requested by the General Land Office, in addition to those herein expressly provided for. Lessee shall have an electrical and/or radioactivity survey made on the bore-hole section, from the base of the surface casing to the total depth of well, of all wells drilled on the above described premises and shall transmit a true copy of the log of each survey on each well to the General Land Office within fifteen (15) days after the making of said survey.

(C) PENALTIES: Lessee shall incur a penalty whenever reports, documents or other materials are not filed in the General Land Office when due. The penalty for late filing shall be set by the General Land Office administrative rule which is effective on the date when the materials were due in the General Land Office.

7. RETAINED ACREAGE: Notwithstanding any provision of this lease to the contrary, after a well producing or capable of producing oil or gas has been completed on the leased premises, Lessee shall exercise the diligence of a reasonably prudent operator in drilling such additional well or wells as may be reasonably necessary for the proper development of the leased premises and in marketing the production thereon.

(A) VERTICAL: In the event this lease is in force and effect two (2) years after the expiration date of the primary or extended term it shall then terminate as to all of the leased premises, EXCEPT (1) 40 acres surrounding each oil well capable of producing in paying quantities and 320 acres surrounding each gas well capable of producing in paying quantities (including a shut-in oil or gas well as provided in Paragraph 11 hereof), or a well upon which Lessee is then engaged in continuous drilling or reworking operations, or (2) the number of acres included in a producing pooled unit pursuant to Natural Resources Code Sections 52.151-52.153, or (3) such greater or lesser number of acres as may then be allocated for production purposes to a proration unit for each such producing well under the rules and regulations of the Railroad Commission of Texas, or any successor agency, or other governmental authority having jurisdiction. Within 90 days of a partial termination of this lease in accordance with this subparagraph and upon payment of the minimum filing fee set by General Land Office rules in effect at the time of the partial termination, Lessee shall have the right to obtain a surface lease for ingress and egress on and across the terminated portion of the leased premises as may be reasonably necessary for the continued operation of the portions of the lease remaining in force and effect. If Lessee fails to apply for a surface lease within the 90 day period specified above, Lessee may apply for a surface lease from the Land Office, but the Land Commissioner has the discretion to grant or deny such application and to set the fee for such surface lease.

(B) HORIZONTAL: In the event this lease is in force and effect two (2) years after the expiration date of the primary or extended term it shall further terminate as to all depths below 100 feet below the total depth drilled (hereinafter "deeper depths") in each well located on acreage retained in Paragraph 7 (A) above, unless on or before two (2) years after the primary or extended term Lessee pays an amount equal to one-half (1/2) of the bonus originally paid as consideration for this lease (as specified on page 1 hereof). If such amount is paid, this lease shall be in force and effect as to such deeper depths, and said termination shall be delayed for an additional period of two (2) years and so long thereafter as oil or gas is produced in paying quantities from such deeper depths covered by this lease.

(C) IDENTIFICATION AND FILING: The surface acreage retained hereunder as to each well shall, as nearly as practical, be in the form of a square with the well located in the center thereof, or such other shape as may be approved by the School Land Board. Within thirty (30) days after partial termination of this lease as provided herein, Lessee shall execute and record a release or releases containing a satisfactory legal description of the acreage and/or depths not retained hereunder. The recorded release, or a certified copy of same, shall be filed in the General Land Office, accompanied by the filing fee prescribed by the General Land Office rules in effect on the date the release is filed. If Lessee fails or refuses to execute and record such release or releases within ninety (90) days after being requested to do so by the General Land Office, then the Commissioner at his sole discretion may designate by written instrument the acreage and/or depths to be released hereunder and record such instrument at Lessee's expense in the county or counties where the lease is located and in the official records of the General Land Office and such designation shall be binding upon Lessee for all purposes. If at any time after the effective date of the partial termination provisions hereof, the applicable field rules are changed or the well or wells located thereon are reclassified so that less acreage is thereafter allocated to said well or wells for production purposes, this lease shall thereupon terminate as to all acreage not thereafter allocated to said well or wells for production purposes.

8. OFFSET WELLS: If oil and/or gas should be produced in commercial quantities from a well located on land privately owned or on State land leased at a lesser royalty, which well is within one thousand (1,000) feet of the area included herein, or which well is draining the area covered by this lease, the Lessee shall, within sixty (60) days after such initial production from the draining well or the well located within one thousand (1,000) feet from the area covered by this lease begin in good faith and prosecute diligently the drilling of an offset well on the area covered by this lease, and such offset well shall be drilled to such depth as may be necessary to prevent the undue drainage of the area covered by this lease, and the Lessee, manager or driller shall use all means necessary in a good faith effort to make such offset well produce oil and/or gas in commercial quantities. Only upon the determination of the Commissioner and with his written approval, may the payment of a compensatory royalty satisfy the obligation to drill an offset well or wells required under this Paragraph.

9. DRY HOLE/CESSATION OF PRODUCTION DURING PRIMARY TERM: If, during the primary term hereof and prior to discovery and production of oil or gas on said land, Lessee should drill a dry hole or holes thereon, or if during the primary term hereof and after the discovery and actual production of oil or gas from the leased premises such production thereof should cease from any cause, this lease shall not terminate if on or before the expiration of sixty (60) days from date of completion of said dry hole or cessation of production Lessee commences additional drilling or reworking operations thereon, or pays or tenders the next annual delay rental in the same manner as provided in this lease. If, during the last year of the primary term or within sixty (60) days prior thereto, a dry hole be completed and abandoned, or the production of oil or gas should cease for any cause, Lessee's rights shall remain in full force and effect without further operations until the expiration of the primary term; and if Lessee has not resumed production in paying quantities at the expiration of the primary term, Lessee may maintain this lease by conducting additional drilling or reworking operations pursuant to Paragraph 10, using the expiration of the primary term as the date of cessation of production under Paragraph 10. Should the first well or any subsequent well drilled on the above described land be completed as a shut-in oil or gas well within the primary term hereof, Lessee may resume payment of the annual rental in the same manner as provided herein on or before the rental paying date following the expiration of sixty (60) days from the date of completion of such shut-in oil or gas well and upon the failure to make such payment, this lease shall ipso facto terminate. If at the expiration of the primary term or any time thereafter a shut-in oil or gas well is located on the leased premises payments may be made in accordance with the shut-in provisions hereof.

10. CESSATION, DRILLING, AND REWORKING: If, after the expiration of the primary term, production of oil or gas from the leased premises, after once obtained, should cease from any cause, this lease shall not terminate if Lessee commences additional drilling or reworking operations within sixty (60) days after such cessation, and this lease shall remain in full force and effect for so long as such operations continue in good faith and in workmanlike manner without interruptions totaling more than sixty (60) days. If such drilling or reworking operations result in the production of oil or gas, the lease shall remain in full force and effect for so long as oil or gas is produced from the leased premises in paying quantities or payment of shut-in oil or gas well royalties or payment of compensatory royalties is made as provided herein or as provided by law. If the drilling or reworking operations result in the completion of a well as a dry hole, the lease will not terminate if the Lessee commences additional drilling or reworking operations within sixty (60) days after the completion of the well as a dry hole, and this lease shall remain in effect so long as Lessee continues drilling or reworking operations in good faith and in a workmanlike manner without interruptions totaling more than sixty (60) days. Lessee shall give written notice to the General Land Office within thirty (30) days of any cessation of production.

11. SHUT-IN ROYALTIES: For purposes of this paragraph, "well" means any well that has been assigned a well number by the state agency having jurisdiction over the production of oil and gas. If at any time after the expiration of the primary term of a lease that, until being shut in, was being maintained in force and effect, a well capable of producing oil or gas in paying quantities is located on the leased premises, but oil or gas is not being produced for lack of suitable production facilities or lack of a suitable market, then Lessee may pay as a shut-in oil or gas royalty an amount equal to double the annual rental provided in the lease, but not less than $1,200 a year for each well capable of producing oil or gas in paying quantities. To be effective, each initial shut-in oil or gas royalty must be paid on or before: (1) the expiration of the primary term, (2) 60 days after the Lessee ceases to produce oil or gas from the leased premises, or (3) 60 days after Lessee completes a drilling or reworking operation in accordance with the lease provisions; whichever date is latest. If the shut-in oil or gas royalty is paid, the lease shall be considered to be a producing lease and the payment shall extend the term of the lease for a period of one year from the end of the primary term, or from the first day of the month following the month in which production ceased, and, after that, if no suitable production facilities or suitable market for the oil or gas exists, Lessee may extend the lease for four more successive periods of one (1) year by paying the same amount each year on or before the expiration of each shut-in year.

12. COMPENSATORY ROYALTIES: If, during the period the lease is kept in effect by payment of the shut-in oil or gas royalty, oil or gas is sold and delivered in paying quantities from a well located within one thousand (1,000) feet of the leased premises and completed in the same producing reservoir, or in any case in which drainage is occurring, the right to continue to maintain the lease by paying the shut-in oil or gas royalty shall cease, but the lease shall remain effective for the remainder of the year for which the royalty has been paid. The Lessee may maintain the lease for four more successive years by Lessee paying compensatory royalty at the royalty rate provided in the lease of the market value of production from the well causing the drainage or which is completed in the same producing reservoir and within one thousand (1,000) feet of the leased premises. The compensatory royalty is to be paid monthly to the Commissioner beginning on or before the last day of the month following the month in which the oil or gas is produced from the well causing the drainage or that is completed in the same producing reservoir and located within one thousand (1,000) feet of the leased premises; if the compensatory royalty paid in any 12-month period is in an amount less than the annual shut-in oil or gas royalty, Lessee shall pay an amount equal to the difference within thirty (30) days from the end of the 12-month period; and none of these provisions will relieve Lessee of the obligation of reasonable development nor the obligation to drill offset wells as provided in N.R.C. Section 52.034; however, at the determination of the Commissioner, and with the Commissioner's written approval, the payment of compensatory royalties shall satisfy the obligation to drill offset wells. Compensatory royalty payments which are not timely paid will accrue penalty and interest in accordance with Paragraph 5 of this lease.

13. EXTENSIONS: If, at the expiration of the primary term of this lease, production of oil or gas has not been obtained on the leased premises but drilling operations are being conducted thereon in good faith and in a good and workmanlike manner, Lessee may, on or before the expiration of the primary term, file in the General Land Office written application to the Commissioner of the General Land Office for a thirty (30) day extension of this lease, accompanied by payment of Three Thousand Dollars ($3,000.00) if this lease covers six hundred forty (640) acres or less and Six Thousand Dollars ($6,000.00) if this lease covers more than six hundred forty (640) acres and the Commissioner shall, in writing, extend this lease for a thirty (30) day period from and after the expiration of the primary term and so long thereafter as oil or gas is produced in paying quantities; provided further, that Lessee may, so long as such drilling operations are being conducted make like application and payment during any thirty (30) day extended period for an additional extension of thirty (30) days and, upon receipt of such application and payment, the Commissioner shall, in writing, again extend this lease so that same shall remain in force for such additional thirty (30) day period and so long thereafter as oil or gas is produced in paying quantities; provided, however, that this lease shall not be extended for more than a total of three hundred ninety (390) days from and after the expiration of the primary term unless production in paying quantities has been obtained.

14. USE OF WATER; SURFACE: Lessee shall have the right to use water produced on said land necessary for operations hereunder and solely upon the leased premises; provided, however, Lessee shall not use potable water or water suitable for livestock or irrigation purposes for water flood operations without the prior written consent of Lessor. Subject to its obligation to pay surface damages, Lessee shall have the right to use so much of the surface of the land that may be reasonably necessary for drilling and operating wells and transporting and marketing the production therefrom, such use to be conducted under conditions of least injury to the surface of the land. Lessee shall pay surface damages in an amount set by the General Land Office fee schedule which is effective on the date when the activity requiring the payment of surface damages occurs.

15. POLLUTION: In developing this area, Lessee shall use the highest degree of care and all proper safeguards to prevent pollution. Without limiting the foregoing, pollution of coastal wetlands, natural waterways, rivers and impounded water shall be prevented by the use of containment facilities sufficient to prevent spillage, seepage or ground water contamination. In the event of pollution, Lessee shall use all means at its disposal to recapture all escaped hydrocarbons or other pollutant and shall be responsible for all damage to public and private properties.

(A) UPLANDS: Lessee shall build and maintain fences around its slush, sump, and drainage pits and tank batteries so as to protect livestock against loss, damage or injury; and upon completion or abandonment of any well or wells, Lessee shall fill and level all slush pits and cellars and completely clean up the drilling site of all rubbish thereon.

(B) SUBMERGED LANDS: No discharge of solid waste or garbage shall be allowed into State waters from any drilling or support vessels, production platform, crew or supply boat, barge, jack-up rig or other equipment located on the leased area. Solid waste shall include but shall not be limited to containers, equipment, rubbish, plastic, glass, and any other man-made non-biodegradable items. A sign must be displayed in a high traffic area on all vessels and manned platforms stating, "Discharge of any solid waste or garbage into State Waters from vessels or platforms is strictly prohibited and may subject a State of Texas lease to forfeiture." Such statement shall be in lettering of at least 1" in size.

(C) RIVERS: To the extent necessary to prevent pollution, the provisions found in subsections (a) and (b) of this paragraph shall also apply to rivers and riverbeds.

(D) PENALTY: Failure to comply with the requirements of this provision may result in the maximum penalty allowed by law including forfeiture of the lease. Lessee shall be liable for the damages caused by such failure and any costs and expenses incurred in cleaning areas affected by the discharged waste.

16. IDENTIFICATION MARKERS: Lessee shall erect, at a distance not to exceed twenty-five (25) feet from each well on the premises covered by this lease, a legible sign on which shall be stated the name of the operator, the lease designation and the well number. Where two or more wells on the same lease or where wells on two or more leases are connected to the same tank battery, whether by individual flow line connections direct to the tank or tanks or by use of a multiple header system, each line between each well and such tank or header shall be legibly identified at all times, either by a firmly attached tag or plate or an identification properly painted on such line at a distance not to exceed three (3) feet from such tank or header connection. Said signs, tags, plates or other identification markers shall be maintained in a legible condition throughout the term of this lease.

17. ASSIGNMENTS: The lease may be transferred at any time; provided, however, that the liability of the transferor to properly discharge its obligation under the lease, including properly plugging abandoned wells, removing platforms or pipelines, or remediation of contamination at drill sites shall pass to the transferee upon the prior written consent of the Commissioner of the General Land Office. The Commissioner may require the transferee to demonstrate financial responsibility and may require a bond or other security. All transfers must reference the lease by the file number and must be recorded in the county where the area is located, and the recorded transfer or a copy certified to by the County Clerk of the county where the transfer is recorded must be filed in the General Land Office within ninety (90) days of the execution date, as provided by N.R.C. Section 52.026, accompanied by the filing fee prescribed by the General Land Office rules in effect on the date of receipt by the General Land Office of such transfer or certified copy thereof. Every transferee shall succeed to all rights and be subject to all obligations, liabilities, and penalties owed to the State by the original lessee or any prior transferee of the lease, including any liabilities to the state for unpaid royalties.

18. RELEASES: Lessee may relinquish the rights granted hereunder to the State at any time by recording the relinquishment in the county where this area is situated and filing the recorded relinquishment or certified copy of same in the General Land Office within ninety (90) days after its execution accompanied by the filing fee prescribed by the General Land Office rules in effect on the date of receipt by the General Land Office of such relinquishment or certified copy thereof. Such relinquishment will not have the effect of releasing Lessee from any liability theretofore accrued in favor of the State.

19. LIEN: In accordance with N.R.C. Section 52.136, the State shall have a first lien upon all oil and gas produced from the area covered by this lease to secure payment of all unpaid royalty and other sums of money that may become due under this lease. By acceptance of this lease, Lessee grants the State, in addition to the lien provided by N.R.C. Section 52.136 and any other applicable statutory lien, an express contractual lien on and security interest in all leased minerals in and extracted from the leased premises, all proceeds which may accrue to Lessee from the sale of such leased minerals, whether such proceeds are held by Lessee or by a third party, and all fixtures on and improvements to the leased premises used in connection with the production or processing of such leased minerals in order to secure the payment of all royalties or other amounts due or to become due under this lease and to secure payment of any damages or loss that Lessor may suffer by reason of Lessee's breach of any covenant or condition of this lease, whether express or implied. This lien and security interest may be foreclosed with or without court proceedings in the manner provided in the Title 1, Chapter 9 of the Texas Business and Commerce Code. Lessee agrees that the Commissioner may require Lessee to execute and record such instruments as may be reasonably necessary to acknowledge, attach or perfect this lien. Lessee hereby represents that there are no prior or superior liens arising from and relating to Lessee's activities upon the above-described property or from Lessee's acquisition of this lease. Should the Commissioner at any time determine that this representation is not true, then the Commissioner may declare this lease forfeited as provided herein.

20. FORFEITURE: If Lessee shall fail or refuse to make the payment of any sum within thirty (30) days after it becomes due, or if Lessee or an authorized agent should knowingly make any false return or false report concerning production or drilling, or if Lessee shall fail or refuse to drill any offset well or wells in good faith as required by law and the rules and regulations adopted by the Commissioner of the General Land Office, or if Lessee should fail to file reports in the manner required by law or fail to comply with rules and regulations promulgated by the General Land Office, the School Land Board, or the Railroad Commission, or refuse the proper authority access to the records pertaining to operations, or if Lessee or an authorized agent should knowingly fail or refuse to give correct information to the proper authority, or knowingly fail or refuse to furnish the General Land Office a correct log of any well, or if Lessee shall knowingly violate any of the material provisions of this lease, or if this lease is assigned and the assignment is not filed in the General Land Office as required by law, the rights acquired under this lease shall be subject to forfeiture by the Commissioner, and he shall forfeit same when sufficiently informed of the facts which authorize a forfeiture, and when forfeited the area shall again be subject to lease to the highest bidder, under the same regulations controlling the original sale of leases. However, nothing herein shall be construed as waiving the automatic termination of this lease by operation of law or by reason of any special limitation arising hereunder. Forfeitures may be set aside and this lease and all rights thereunder reinstated before the rights of another intervene upon satisfactory evidence to the Commissioner of the General Land Office of future compliance with the provisions of the law and of this lease and the rules and regulations that may be adopted relative hereto.

21. RIVERBED TRACTS: In the event this lease covers a riverbed, Lessee is hereby specifically granted the right of eminent domain and condemnation as provided for in N.R.C. Sections 52.092-52.093, as a part of the consideration moving to Lessor for the covenants herein made by Lessee.

22. APPLICABLE LAWS AND DRILLING RESTRICTIONS: This lease shall be subject to all rules and regulations, and amendments thereto, promulgated by the Commissioner of the General Land Office governing drilling and producing operations on Permanent Free School Land (specifically including any rules promulgated that relate to plans of operations), payment of royalties, and auditing procedures, and shall be subject to all other valid statutes, rules, regulations, orders and ordinances that may affect operations under the provisions of this lease. Without limiting the generality of the foregoing, Lessee hereby agrees, by the acceptance of this lease, to be bound by and subject to all statutory and regulatory provisions relating to the General Land Office's audit billing notice and audit hearings procedures. Said provisions are currently found at 31 Texas Administrative Code, Chapter 4, and Texas Natural Resources Code Sections 52.135 and 52.137 through 52.140. In the event this lease covers land franchised or leased or otherwise used by a navigation district or by the United States for the purpose of navigation or other purpose incident to the operation of a port, then Lessee shall not be entitled to enter or possess such land without prior approval as provided under Section 61.117 of the Texas Water Code, but Lessee shall be entitled to develop such land for oil and gas by directional drilling; provided, however, that no surface drilling location may be nearer than 660 feet and special permission from the Commissioner of the General Land Office is necessary to make any surface location nearer than 2,160 feet measured at right angles from the nearest bulkhead line or from the nearest dredged bottom edge of any channel, slip, or turning basin which has been authorized by the United States as a federal project for future construction, whichever is nearer.

23. REMOVAL OF EQUIPMENT: Upon the termination of this lease for any cause, Lessee shall not, in any event, be permitted to remove the casing or any part of the equipment from any producing, dry, or abandoned well or wells without the written consent of the Commissioner of the General Land Office or his authorized representative; nor shall Lessee, without the written consent of said Commissioner or his authorized representative remove from the leased premises the casing or any other equipment, material, machinery, appliances or property owned by Lessee and used by Lessee in the development and production of oil or gas therefrom until all dry or abandoned wells have been plugged and until all slush or refuse pits have been properly filled and all broken or discarded lumber, machinery, or debris shall have been removed from the premises to the satisfaction of said Commissioner or his authorized representative.

24. FORCE MAJEURE: Should Lessee be prevented from complying with any express or implied covenant of this lease, from conducting drilling operations thereon, or from producing oil and/or gas therefrom, after effort made in good faith, by reason of war, rebellion, riots, strikes, fires, acts of God or any order, rule or regulation of governmental authority, then while so prevented, Lessee's obligation to comply with such covenant shall be suspended upon proper and satisfactory proof presented to the Commissioner of the General Land Office in support of Lessee's contention and Lessee shall not be liable for damages for failure to comply therewith (except in the event of lease operations suspended as provided in the rules and regulations adopted by the School Land Board); and this lease shall be extended while and so long as Lessee is prevented, by any such cause, from drilling, reworking operations or producing oil and/or gas from the leased premises; provided, however, that nothing herein shall be construed to suspend the payment of rentals during the primary or extended term, nor to abridge Lessee's right to a suspension under any applicable statute of this State.

25. LEASE SECURITY: Lessee shall take the highest degree of care and all proper safeguards to protect said premises and to prevent theft of oil, gas, and other hydrocarbons produced from said lease. This includes, but is not limited to, the installation of all necessary equipment, seals, locks, or other appropriate protective devices on or at all access points at the lease's production, gathering and storage systems where theft of hydrocarbons can occur. Lessee shall be liable for the loss of any hydrocarbons resulting from theft and shall pay the State of Texas royalties thereon as provided herein on all oil, gas or other hydrocarbons lost by reason of theft.

26. REDUCTION OF PAYMENTS: If, during the primary term, a portion of the land covered by this lease is included within the boundaries of a pooled unit that has been approved by the School Land Board in accordance with Natural Resources Code Sections 52.151-52.153, or if, at any time after the expiration of the primary term or the extended term, this lease covers a lesser number of acres than the total amount described herein, payments that are made on a per acre basis hereunder shall be reduced according to the number of acres pooled, released, surrendered, or otherwise severed, so that payments determined on a per acre basis under the terms of this lease during the primary term shall be calculated based upon the number of acres outside the boundaries of a pooled unit, or, if after the expiration of the primary term, the number of acres actually retained and covered by this lease.

27. SUCCESSORS AND ASSIGNS: The covenants, conditions and agreements contained herein shall extend to and be binding upon the heirs, executors, administrators, successors or assigns of Lessee herein.

28. ANTIQUITIES CODE: In the event that any feature of archeological or historical interest on Permanent School Fund Land is encountered during the activities authorized by this lease, Lessee will immediately cease activities and will immediately notify the General Land Office (ATTN. Archaeologist, Asset Management Division, 1700 N. Congress Ave., Austin, Texas 78701) and the Texas Historical Commission (P.O. Box 12276, Austin, TX 78711) so that adequate measures may be undertaken to protect or recover such discoveries or findings, as appropriate. Lessee is expressly placed on notice of the National Historical Preservation Act of 1966 (PB-89-66, 80 Statute 915; 16 U.S.C.A. 470) and the Antiquities Code of Texas, Chapter 191, Tex. Nat. Code Ann. (Vernon 1993 & Supp. 1998). On state-owned land not dedicated to the Permanent School Fund, lessee shall notify the Texas Historical Commission before breaking ground at a project location. An archaeological survey might be required by the commission before construction of the project can commence. Further, in the event that any site, object, location, artifact or other feature of archaeological, scientific, educational, cultural or historic interest is encountered during the activities authorize by this lease, lessee will immediately notify lessor and the Texas Historical Commission so that adequate measures may be undertaken to protect or recover such discoveries or findings, as appropriate.

29. VENUE: Lessor and lessee, including lessee's successors and assigns, hereby agree that venue for any dispute arising out of a provision of this lease, whether express or implied, regarding interpretation of this lease, or relating in any way to this lease or to applicable case law, statutes, or administrative rules, shall be in a court of competent jurisdiction located in Travis County, State of Texas.

30. LEASE FILING: Pursuant to Chapter 9 of the Tex. Bus. & Com. Code, this lease must be filed of record in the office of the County Clerk in any county in which all or any part of the leased premises is located, and certified copies thereof must be filed in the General Land Office.

31. EXECUTION: This oil and gas lease must be signed and acknowledged by the Lessee before it is filed of record in the county records and in the General Land Office of the State of Texas.

____
LESSEE

BY:____

TITLE:____

DATE:____

IN TESTIMONY WHEREOF, witness the signature of the Commissioner of the General Land Office of the State of Texas under the seal of the General Land Office.

____
COMMISSIONER OF THE GENERAL LAND OFFICE
OF THE STATE OF TEXAS

APPROVED

Contents _____
Legal _____
DC _____
Exec _____

STATE OF ______________________ (CORPORATION ACKNOWLEDGMENT)
COUNTY OF ___________________
Before me, the undersigned authority, on this day personally appeared_________ ____known to me to be the person whose name is subscribed to the foregoing instrument, as __________________________________ of____ and acknowledged to me that he executed the same for the purposes and consideration therein expressed, in the capacity stated, and as the act and deed of said corporation.
Given under my hand and seal of office this the______ day of______, 19________.

Notary Public in and for ____
____

STATE OF ______________________ (INDIVIDUAL ACKNOWLEDGMENT)
COUNTY OF ____________________
Before me, the undersigned authority, on this day personally appeared_________________ ______________________________________ known to me to be the persons whose names are subscribed to the foregoing instrument, and acknowledged to me that they executed the same for the purposes and consideration therein expressed.
Given under my hand and seal of office this _____the day of________, 19_______.

Notary Public in and for____
____

APPENDIX 8: ILLUSTRATIVE DAY RATE DRILLING CONTRACT

NOTE: This is the June 1994 version of the form. Contact the International Association of Drilling Contractors (IADC) at www.iadc.org for the most recent forms for daywork, footage, and turnkey contracts.

This form contract is a suggested guide only and use of this form or any variation thereof shall be at the sole discretion and risk of the user parties. Users of the form contract or any portion or variation thereof are encouraged to seek the advice of counsel to ensure that their contract reflects the complete agreement of the parties and applicable law. The International Association of Drilling Contractors disclaims any liability whatsoever for loss or damages which may result from use of the form contract or portions or variations thereof.

INTERNATIONAL ASSOCIATION OF DRILLING CONTRACTORS

DRILLING BID PROPOSAL
AND
DAYWORK DRILLING CONTRACT - U.S.

TO: ____

____

____

Please submit bid on this drilling contract form for performing the work outlined below, upon the terms and for the consideration set forth, with the understanding that if the bid is accepted by____

____

this instrument will constitute a contract between us. Your bid should be mailed or delivered not later than _______ P.M. on ___________________ , l 9__ to the following address:

____

____

* * * * *

THIS AGREEMENT CONTAINS PROVISIONS RELATING TO INDEMNITY, RELEASE OF LIABILITY, AND ALLOCATION OF RISK

THIS AGREEMENT (The "Contract") is made and entered into on the date hereinafter set forth by and between the parties herein designated as "Operator" and " Contractor ".
OPERATOR:____

Address:____

CONTRACTOR:____

Address____

IN CONSIDERATION of the mutual promises, conditions and agreements herein contained and the specifications and special provisions set forth in Exhibit "A" and Exhibit "B" attached hereto and made a part hereof, Operator engages Contractor as an Independent Contractor to drill the hereinafter designated well or wells in search of oil or gas on a daywork basis.

For purposes hereof, the term "daywork basis" means Contractor shall furnish equipment, labor, and perform services as herein provided, for a specified sum per day under the direction, supervision and control of Operator (inclusive of any employee, agent, consultant or subcontractor engaged by Operator to direct drilling operations). When operating on a daywork basis, Contractor shall be fully paid at the applicable rates of payment and assumes only the obligations and liabilities stated herein. Except for such obligations and liabilities specifically assumed by Contractor, Operator shall be solely responsible and assumes liability for all consequences of operations by both parties while on a daywork basis, including results and all other risks or liabilities incurred in or incident to such operations.

1. LOCATION OF WELL:

Well Name
and Number:____
Parish/ Field
County: ___________State: ____________Name________________________________
Well location and
land description____
____

1.1 Additional Well Locations or Areas:____
____
Locations described above are for well and Contract identification only and Contractor assumes no liability whatsoever for a proper survey or location stake on Operator's lease.

2. COMMENCEMENT DATE:

Contractor agrees to use reasonable efforts to commence operations for the drilling of the well by the ______________ day of ___________________ , 19____ , or___________
____

3. DEPTH:

3.1 Well Depth: The well(s) shall be drilled to a depth of approximately______________ _____________feet, or to the __________________________ formation, whichever is deeper, but the Contractor shall not be required hereunder to drill said well(s) below a maximum depth of __________ feet, unless Contractor and Operator mutually agree to drill to a greater depth.

4. DAYWORK RATES:

Contractor shall be paid at the following rates for the work performed hereunder.

4.1 Mobilization: Operator shall pay Contractor a mobilization fee of $________ or a mobilization day rate of $_________ per day. This sum shall be due and payable in full at the time the rig is rigged up or positioned at the well site ready to spud. Mobilization shall include:____
____

4.2 Demobilization: Operator shall pay Contractor a demobilization fee of $__________or a demobilization day rate during tear down of $____________ per day, provided however that no demobilization fee shall be payable if the Contract is terminated due to the total loss or destruction of the rig. Demobilization shall include___________________________________
____

4.3 Moving Rate: During the time the rig is in transit to or from a drill site, or between drill sites, commencing on _________________ , Operator shall pay Contractor a sum of $_______ twenty-four (24) hour day.

4.4 Operating Day Rate: For work performed per twenty-four (24) hour day with _______ man crew the operating day rate shall be:

Depth Intervals From	To	Without Drill Pipe	With Drill Pipe
_______________	_________________	$____________ per day	$____________ per day
_______________	_________________	$____________ per day	$____________ per day
_______________	_________________	$____________ per day	$____________ per day

Using Operator's drill pipe $_______________ per day.

If under the above column "With Drill Pipe" no day rates are specified, the daywork rate per twenty-four hour day when drill pipe is in use shall be the applicable daywork rate specified in the column "Without Drill Pipe" plus compensation for any drill pipe actually used at the rates specified below, computed on the basis of the maximum drill pipe in use at any time during each twenty-four hour day.

DRILL PIPE RATES PER 24-HOUR DAY

Straight Hole	Size	Grade	Directional or Uncontrollable Deviated Hole	Size	Grade
$_________per ft.	______	___________	$___________________per ft.	______	______
$_________per ft.	______	___________	$___________________per ft.	______	______
$_________per ft.	______	___________	$___________________per ft.	______	______

Directional or uncontrolled deviated hole will be deemed to exist when deviation exceeds ____________ degrees or when the change of angle exceeds ________ degrees per one hundred feet.

Drill pipe shall be considered in use not only when in actual use but also while it is being picked up or laid down. When drill pipe is standing in the derrick, it shall not be considered in use, provided, however, that if Contractor furnishes special strings of drill pipe, drill collars, and handling tools as provided for in Exhibit "A", the same shall be considered in use at all times when on location or until released by Operator. In no event shall fractions of an hour be considered in computing the amount of time drill pipe is in use but such time shall be computed to the nearest hour, with thirty minutes or more being considered a full hour and less than thirty minutes not to be counted.

Operating rate will begin when the drilling unit is rigged up at the drilling location, or positioned over the location during marine work, and ready to commence operations; and will cease when the rig is ready to be moved off the location.

4.5 Repair Rate: In the event it is necessary to shut down Contractor's rig for repairs, excluding routine rig servicing, while Contractor is performing daywork hereunder, Contractor shall be allowed compensation at the applicable daywork rate for each period of shutdown time up to a maximum of ____________ hours for any one repair job and a total of ___________hours for each thirty (30) day period. Thereafter, Contractor shall be compensated at a rate of $__________ per twenty-four (24) hour day.__________________ ______________________________________ shall not be included in computing the number of hours of shutdown time.

4.6 Standby Time Rate with Crews: $ _______________ per twenty-four (24) hour day. Standby time shall be defined to include time when the rig is shut down although in readiness to begin or resume operations but Contractor is waiting on orders of Operator or on materials, services or other items to be furnished by Operator.

4.7 Force Majeure Rate: $___________ per twenty-four (24) hour day for any continuous period that normal operations are suspended or cannot be carried on due to conditions of force majeure as defined in Paragraph 17 hereof. It is, however, understood that subject to Paragraph 6.3 below, Operator can release the rig in accordance with Operator's right to direct stoppage of the work, effective when conditions will permit the rig to be moved from the location.

4.8 Reimbursable Costs: Operator shall reimburse Contractor for the costs of material, equipment, work or services which are to be furnished by Operator as provided for herein but which for convenience are actually furnished by Contractor at Operator's request, plus percent for such cost of handling.

4.9 Revision in Rates: The rates and/or payments herein set forth due to Contractor from Operator shall be revised to reflect the change in costs if the costs of any of the items hereinafter listed shall vary by more than _______ percent from the costs thereof on the date of this Contract or by the same percent after the date of any revision pursuant to this paragraph:

(a) Labor costs, including all benefits, of Contractor's personnel;
(b) Contractor's cost of insurance premiums;
(c) Contractor's cost of fuel, including all taxes and fees; the cost per gallon/MCF being $__________;
(d) Contractor's cost of catering, when applicable;
(e) If Operator requires Contractor to increase or decrease the number of Contractor's personnel;
(f) Contractor's cost of spare parts and supplies with the understanding that such spare parts and supplies constitute _____ percent of the Operating Rate and that the parties shall use the U.S. Bureau of Labor Statistics Oilfield Drilling Machinery and Equipment Wholesale Price Index (Code No. 1191-02) to determine to what extent a price variance has occurred in said spare parts and supplies;
(g) If there is any change in legislation or regulations in the area in which Contractor is working or other unforeseen, unusual event that alters Contractor's financial burden.

5. TIME OF PAYMENT:

Payment is due by Operator to Contractor as follows:

5.1 Payment for mobilization, drilling and other work performed at applicable day rates, and all other applicable charges shall be due, upon presentation of invoice therefor, upon completion of mobilization, completion of the well, or at the end of the month in which such work was performed or other charges are incurred, whichever shall first occur. All invoices may be mailed to Operator at the address hereinabove shown, unless Operator does hereby designate that such invoices shall be mailed as follows:

____

5.2 Disputed Invoices and Late Payment: Operator shall pay all invoices within days after receipt except that if Operator disputes an invoice of any part thereof, Operator shall, within fifteen days after receipt of the invoice, notify Contractor of the item disputed, specifying the reason therefor, and payment of the disputed item may be withheld until settlement of the dispute, but timely payment shall be made of any undisputed portion. Any sums (including amounts ultimately paid with respect to a disputed invoice) not paid within the above specified days shall bear interest at the rate of __________ percent or the maximum legal rate, which ever is less, per month from the due date until paid. If Operator does not pay undisputed items within the above stated time, Contractor may terminate this Contract as specified under Subparagraph 6.3.

5.3 Attorney's Fees: If this Contract is placed in the hands of an attorney for collection of any sums due hereunder, or suit is brought on same, or sums due hereunder are collected through bankruptcy or probate proceedings, then Operator agrees that there shall be added to the amount due reasonable attorney's fees and costs.

6. TERM:

6.1 Duration of Contract: This Contract shall remain in full force and effect until drilling operations are completed on the well or wells specified in Paragraph 1 above, or for a term of _______________________, commencing on the date specified in Paragraph 2 above.

6.2 Extension of Term: Operator may extend the term of this Contract for well(s) or for a period of _______________________________ by giving notice to Contractor at least ______ days prior to completion of the well then being drilled or by

____

6.3 Early Termination:

(a) **By Either Party**: Upon giving of written notice, either party may terminate this Contract when total loss or destruction of the rig, or a major breakdown with indefinite repair time necessitate stopping operations hereunder.

(b) **By Operator**: Notwithstanding the provisions of Paragraph 3 with respect to the depth to be drilled, Operator shall have the right to direct the stoppage of the work to be performed by Contractor hereunder at any time prior to reaching the specified depth, and even though Contractor has made no default hereunder. In such event Operator shall reimburse Contractor as set forth in Subparagraph 6.4 hereof.

(c) **By Contractor**: Notwithstanding the provisions of Paragraph 3 with respect to the depth to be drilled, in the event Operator shall become insolvent, or be adjudicated a bankrupt, or file, by way of petition or answer, a debtor's petition or other pleading seeking adjustment of Operator's debts, under any bankruptcy or debtor's relief laws now or hereafter prevailing, or if any such be filed against Operator, or in case a receiver be appointed of Operator or Operator's property, or any part thereof, or Operator's affairs be placed in the hands of a Creditor's Committee, or, following ten days prior written notice to Operator if Operator does not pay Contractor within the time specified in Subparagraph 5.2 all undisputed items due and owing, Contractor may, at its option, elect to terminate further performance of any work under this Contract and Contractor's right to compensation shall be as set forth in Subparagraph 6.4 hereof. In addition to Contractor's right to terminate performance hereunder, Operator hereby expressly agrees to protect, defend and indemnify

Contractor from and against any claims, demands and causes of action, including all costs of defense, in favor of Operator, Operator's joint ventures, or other parties arising out of any drilling commitments or obligations contained in any lease, farmout agreement or other agreement, which may be affected by such termination of performance hereinunder.

6.4 Early Termination Compensation:

(a) **Prior to Commencement**: In the event Operator terminates this Contract prior to commencement of operations hereunder, Operator shall pay Contractor as liquidated damages and not as a penalty a sum equal to the Standby Rate with Crews (Paragraph 4.6) for a period of _______________ days or a lump sum of $____________.

(b) **Prior to Spudding**: If such termination occurs after commencement of operations but prior to the spudding of the well, Operator shall pay to Contractor the sum of the following: (1) all expenses reasonably and necessarily incurred and to be incurred by Contractor by reason of the Contract and by reason of the premature termination of the work, including the expense of drilling or other crew members and supervision directly assigned to the rig; (2) ten percent (10%) of the amount of such reimbursable expenses; and (3) a sum calculated at the standby rate for all time from the date upon which Contractor commences any operations hereunder down to such date subsequent to the date of termination as will afford Contractor reasonable time to dismantle its rig and equipment provided, however, if this Contract is for a term of more than one well or for a period of time, Operator shall pay Contractor, in addition to the above, the force majeure rate, less any unnecessary labor, from that date subsequent to termination upon which Contractor completes dismantling its rig and equipment until the end of the term____

____

____

(c) **Subsequent to Spudding**: If such termination occurs after the spudding of the well, Operator shall pay Contractor (1) the amount for all applicable daywork rates and all other charges and reimbursements due to Contractor; but in no event shall such sum, exclusive of reimbursements due, be less than would have been earned for ____________ days at the applicable day rate "Without Drill Pipe" and the actual amount due for drill pipe used in accordance with the above rates; or (2) at the election of Contractor and in lieu of the foregoing, Operator shall pay Contractor for all expenses reasonably and necessarily incurred and to be incurred by reason of this Contract and by reason of such premature termination plus a lump sum of $___________ provided, however, if this Contract is for a term of more than one well or for a period of time, Operator shall pay Contractor, in addition to the above, the force majeure rate less any unnecessary labor from the date of termination until the end of the term or ____

____

7. CASING PROGRAM:

Operator shall have the right to designate the points at which casing will be set and the manner of setting, cementing and testing. Operator may modify the casing program, however, any such modification which materially increases Contractor's hazards or costs can only be made by mutual consent of Operator and Contractor and upon agreement as to the additional compensation to be paid Contractor as a result thereof.

8. DRILLING METHODS AND PRACTICES:

8.1 Contractor shall maintain well control equipment in good condition at all times and shall use all reasonable means to prevent and control fires and blowouts and to protect the hole.

8.2 Subject to the terms hereof, and at Operator's cost, at all times during the drilling of the well, Operator shall have the right to control the mud program, and the drilling fluid must be of a type and have characteristics and be maintained by Contractor in accordance with the specifications shown in Exhibit "A".

8.3 Each party hereto agrees to comply with all laws, rules, and regulations of any federal, state, or local governmental authority which are now or may become applicable to that party's operations covered by or arising out of the performance of this Contract. When required by law, the terms of Exhibit "B" shall apply to this Contract. In the event any provision of this Contract is inconsistent with or contrary to any applicable federal, state or local law, rule or regulation, said provision shall be deemed to be modified to the extent required to comply with said law, rule or regulation, and as so modified said provision and this Contract shall continue in full force and effect.

8.4 Contractor shall keep and furnish to Operator an accurate record of the work performed and formations drilled on the IADC-API Daily Drilling Report Form or other form acceptable to Operator. A legible copy of said form signed by Contractor's representative shall be furnished by Contractor to Operator.

8.5 If requested by Operator, Contractor shall furnish Operator with a copy of delivery tickets covering any material or supplies provided by Operator and received by Contractor.

9. INGRESS, EGRESS, AND LOCATION:

Operator hereby assigns to Contractor all necessary rights of ingress and egress with respect to the tract on which the well is to be located for the performance by Contractor of all work contemplated by this Contract. Should Contractor be denied free access to the location for any reason not reasonably within Contractor's control, any time lost by Contractor as a result of such denial shall be paid for at the applicable rate. Operator agrees at all times to maintain the road and location in such a condition that will allow free access and movement to and from the drilling site in an ordinarily equipped highway type vehicle. If Contractor is required to use bulldozers, tractors, four-wheel drive vehicles, or any other specialized transportation equipment for the movement of necessary personnel, machinery, or equipment over access roads or on the drilling location, Operator shall furnish the same at its expense and without cost to Contractor. The actual cost of repairs to any transportation equipment furnished by Contractor or its personnel damaged as a result of improperly maintained access roads or location will be charged to Operator. Operator shall reimburse Contractor for all amounts reasonably expended by Contractor for repairs and/or reinforcement of roads, bridges and related or similar facilities (public and private) required as a direct result of a rig move pursuant to performance hereunder.

10. SOUND LOCATION:

Operator shall prepare a sound location adequate in size and capable of properly supporting the drilling rig, and shall be responsible for a conductor pipe program adequate to prevent soil and subsoil wash out. It is recognized that Operator has superior knowledge of the location and access routes to the location, and must advise Contractor of any subsurface conditions, or obstructions (including, but not limited to, mines, caverns, sink holes, streams, pipelines, power lines and telephone lines) which Contractor might encounter while en route to the location or during operations hereunder. In the event subsurface conditions cause a cratering or shifting of the location surface, or if seabed conditions prove unsatisfactory to properly support the rig during marine operations hereunder, and loss or damage to the rig or its associated equipment results therefrom, Operator shall, without regard to other provisions of this Contract, including Paragraph 14.1 hereof, reimburse Contractor to the extent not covered by Contractor's insurance, for all such loss or damage including payment of force majeure rate during repair and/or demobilization if applicable.

11. EQUIPMENT CAPACITY:

If applicable hereunder, operations shall not be attempted where canal or water depths are in excess of ___________________________ feet, or under any other conditions which exceed the capacity of the equipment specified to be used hereunder. Contractor shall make final decision as to when an operation or attempted operation would exceed the capacity of specified equipment.

12. TERMINATION OF LOCATION LIABILITY:

When Contractor has complied with all obligations of the Contract regarding restoration of Operator's location, Operator shall thereafter be liable for damage to property, personal injury or death of any person which occurs as a result of conditions of the location and Contractor shall be relieved of such liability; provided, however, if Contractor shall subsequently reenter upon the location for any reason, including removal of the rig, any term of the Contract relating to such reentry activity shall become applicable during such period.

13. INSURANCE:

During the life of this Contract, Contractor shall at Contractor's expense maintain, with an insurance company or companies authorized to do business in the state where the work is to be performed or through a self-insurance program, insurance coverages of the kind and in the amounts set forth in Exhibit "A", insuring the liabilities specifically assumed by Contractor in Paragraph 14 of this Contract. Contractor shall, if requested to do so by Operator, procure from the company or companies writing said insurance a certificate or certificates that said insurance is in full force and effect and that the same shall not be canceled or materially changed without ten (10) days prior written notice to Operator. For liabilities assumed hereunder by Contractor, its insurance shall be endorsed to provide that the underwriters waive their right of subrogation against Operator. Operator will, as well, cause its insurer to waive subrogation against Contractor for liability it assumes and shall maintain, at Operator's expense, or shall self insure, insurance coverage of the same kind and in the same amount as is required of Contractor, insuring the liabilities specifically assumed by Operator in Paragraph 14 of this Contract.

14. RESPONSIBILITY FOR LOSS OR DAMAGE, INDEMNITY, RELEASE OF LIABILITY AND ALLOCATION OF RISK:

14.1 Contractor's Surface Equipment: Contractor shall assume liability at all times for damage to or destruction of Contractor's surface equipment, regardless of when or how such damage or destruction occurs, and Contractor shall release Operator of any liability for any such loss, except loss or damage under the provisions of Paragraphs 10 or 14.3.

14.2 Contractor's In-Hole Equipment: Operator shall assume liability at all times for damage to or destruction of Contractor's in-hole equipment, including, but not limited to, drill pipe, drill collars, and tool joints, and Operator shall reimburse Contractor for the value of any such loss or damage; the value to be determined by agreement between Contractor and Operator as current repair costs or _______ percent of current new replacement cost of such equipment delivered to the well site.

14.3 Contractor's Equipment - Environmental Loss or Damage: Notwithstanding the provisions of Paragraph 14.1 above, Operator shall assume liability at all times for damage to or destruction of Contractor's equipment caused by exposure to highly corrosive or otherwise destructive elements, including those introduced into the drilling fluid.

14.4 Operator's Equipment: Operator shall assume liability at all times for damage to or destruction of Operator's equipment, including, but not limited to, casing, tubing, well head equipment, and platform if applicable, regardless of when or how such damage or destruction occurs, and Operator shall release Contractor of any liability for any such loss or damage.

14.5 The Hole: In the event the hole should be lost or damaged, Operator shall be solely responsible for such damage to or loss of the hole, including the casing therein. Operator shall release Contractor of any liability for damage to or loss of the hole, and shall protect, defend and indemnify Contractor from and against any and all claims, liability, and expense relating to such damage to or loss of the hole.

14.6 Underground Damage: Operator shall release Contractor of any liability for, and shall protect, defend and indemnify Contractor from and against any and all claims, liability, and expense resulting from operations under this Contract on account of injury to, destruction of, or loss or impairment of any property right in or to oil, gas, or other mineral substance or water, if at the time of the act or omission causing such injury, destruction, loss, or impairment, said substance had not been reduced to physical possession above the surface of the earth, and for any loss or damage to any formation, strata, or reservoir beneath the surface of the earth.

14.7 Inspection of Materials Furnished by Operator: Contractor agrees to visually inspect all materials furnished by Operator before using same and to notify Operator of any apparent defects therein. Contractor shall not be liable for any loss or damage resulting from the use of materials furnished by Operator, and Operator shall release Contractor from, and shall protect, defend and indemnify Contractor from and against, any such liability.

14.8 Contractor's Indemnification of Operator: Contractor shall release Operator of any liability for, and shall protect, defend and indemnify Operator, its officers, directors, employees and joint owners from and against all claims, demands, and causes of action of every kind and character, without limit and without regard to the cause or causes thereof or the negligence of any party or parties, arising in connection herewith in favor of Contractor's employees or Contractor's subcontractors or their employees, or Contractor's invitees, on account of bodily injury, death or damage to property. Contractor's indemnity under this paragraph shall be without regard to and without any right to contribution from any insurance maintained by Operator pursuant to Paragraph 13. If it is judicially determined that the monetary limits of insurance required hereunder or of the indemnities voluntarily assumed under Paragraph 14.8 (which Contractor and Operator hereby agree will be supported either by available liability insurance, under which the insurer has no right to subrogation against the indemnitees, or voluntarily self-insured, in part or whole) exceed the maximum limits permitted under applicable law, it is agreed that said insurance requirements or indemnities shall automatically be amended to conform to the maximum monetary limits permitted under such law.

14.9 Operator's Indemnification of Contractor: Operator shall release Contractor of any liability for, and shall protect, defend and indemnify Contractor, its officers, directors, employees and joint owners from and against all claims, demands, and causes of action of every kind and character, without limit and without regard to the cause or causes thereof or the negligence of any party or parties, arising in connection herewith in favor of Operator's employees or Operator's contractors or their employees, or Operator's invitees, other than those parties identified in Paragraph 14.8 on account of bodily injury, death or damage to property. Operator's indemnity under this paragraph shall be without regard to and without any right to contribution from any insurance maintained by Contractor pursuant to Paragraph 13. If it is judicially determined that the monetary limits of insurance required hereunder or of the indemnities voluntarily assumed under Paragraph 14.9 (which Contractor and Operator hereby agree will be supported either by available liability insurance, under which the insurer has no right of subrogation against the indemnitees, or voluntarily self-insured, in part or whole) exceed the maximum limits permitted under applicable law, it is agreed that said insurance requirements or indemnities shall automatically be amended to conform to the maximum monetary limits permitted under such law.

14.10 Liability for Wild Well: Operator shall be liable for the cost of regaining control of any wild well, as well as for cost of removal of any debris, and shall release Contractor of, and Operator shall protect, defend and indemnify Contractor from and against any liability for such cost.

14.11 Pollution and Contamination: Notwithstanding anything to the contrary contained herein, except the provisions of Paragraphs 10 and 12, it is understood and agreed by and between Contractor and Operator that the responsibility for pollution an contamination shall be as follows:

(a) Unless otherwise provided herein, Contractor shall assume all responsibility for, including control and removal of, and shall protect, defend and indemnify Operator from and against all claims, demands and causes of action of every kind and character arising from pollution or contamination, which originates above the surface of the land or water from spills of fuels, lubricants, motor oils, pipe dope, paints, solvents, ballast, bilge and garbage, except unavoidable pollution from reserve pits, wholly in Contractor's possession and control and directly associated with Contractor's equipment and facilities.

(b) Operator shall assume all responsibility for, including control and removal of, and shall protect, defend and indemnify Contractor from and against all claims, demands, and causes of action of every kind and character arising directly or indirectly from all other pollution or contamination which may occur during the conduct of operations hereunder, including, but not limited to, that which may result from fire, blowout, cratering, seepage or any other uncontrolled flow of oil, gas, water or other substance, as well as the use or disposition of all drilling fluids, including, but not limited to, oil emulsion, oil base or chemically treated drilling fluids, contaminated cuttings or cavings, lost circulation and fish recovery materials and fluids. Operator shall release Contractor of any liability for the foregoing.

(c) In the event a third party commits an act or omission which results in pollution or contamination for which either Contractor or Operator, for whom such party is performing work, is held to be legally liable, the responsibility therefor shall be considered, as between Contractor and Operator, to be the same as if the party for whom the work was performed had performed the same and all of the obligations respecting protection, defense, indemnity and limitation of responsibility and liability, as set forth in (a) and (b) above, shall be specifically applied.

14.12 Consequential Damages: Neither party shall be liable to the other for special, indirect or consequential damages resulting from or arising out of this Contract, including, without limitation, loss of profit or business interruptions including loss or delay of production, however same may be caused.

14.13 Indemnity Obligation: Except as otherwise expressly limited herein, it is the intent of parties hereto that all indemnity obligations and/or liabilities assumed by such parties under terms of this Contract, including, without limitation, Paragraphs 14.1 through 14.12 hereof, be without limit and without regard to the cause or causes thereof (including preexisting conditions), the unseaworthiness of any vessel or vessels, strict liability, or the negligence of any party or parties, whether such negligence be sole, joint or concurrent, active or passive. The indemnities, and releases and assumptions of liability extended by the parties hereto under the provisions of Paragraph 14 shall inure to the benefit of the parties, there parent, holding and affiliated companies and their respective officers, directors, employees, agents and servants. The terms and provisions of Paragraphs 14.1 through 14.12 shall have no application to claims or causes of action asserted against Operator or Contractor by reason of any agreement of indemnity with a person or entity not a party hereto.

15. AUDITS:

If any payment provided for hereunder is made on the basis of Contractor's costs, Operator shall have the right to audit Contractor's books and records relating to such costs. Contractor agrees to maintain such books and records for a period of two (2) years from the date such costs were incurred and to make such books and records available to Operator at any reasonable time or times within the period.

16. NO WAIVER EXCEPT IN WRITING:

It is fully understood and agreed that none of the requirements of this Contract shall be considered as waived by either party unless the same is done in writing, and then only by the persons executing the Contract, or other duly authorized agent or representative of the party.

17. FORCE MAJEURE:

Neither Operator nor Contractor shall be liable to the other for any delays or damage or any failure to act due, occasioned or caused by reason of any laws, rules, regulations or orders promulgated by any Federal, State, or Local governmental body or the rules, regulations, or orders of any public body or official purporting to exercise authority or control respecting the operations covered hereby, including the procurance or use of tools and equipment, or due, occasioned or caused by strikes, action of the elements, water conditions, inability to obtain fuel or other critical materials, or other causes beyond the control of the party affected thereby. In the event that either party hereto is rendered unable, wholly or in part, by any of these causes to carry out its obligation under this Contract, it is agreed that such party shall give notice and details of Force Majeure in writing to the other party as promptly as possible after its occurrence. In such cases, the obligations of the party giving the notice shall be suspended during the continuance of any inability so caused except that Operator shall be obligated to pay to Contractor the Force Majeure Rate provided for in Paragraph 4.7 above.

18. GOVERNING LAW:

This Contract shall be construed, governed, interpreted, enforced and litigated, and the relations between the parties determined in accordance with the laws of______________ _________.

19. INFORMATION CONFIDENTIAL:

Upon written request by Operator, information obtained by Contractor in the conduct of drilling operations on this well, including, but not limited to, depth, formations penetrated, the results of coring, testing and surveying, shall be considered confidential and shall not be divulged by Contractor or its employees, to any person, firm, or corporation other than Operator's designated representatives.

20. SUBCONTRACTS BY OPERATOR:

Operator may employ other contractors to perform any of the operations or services to be provided or performed by it according to Exhibit "A".

21. ASSIGNMENT:

Neither party may assign this Contract without the prior written consent of the other, and prompt notice of any such intent to assign shall be given to the other party. In the event of such assignment, the assigning party shall remain liable to the other party as a guarantor of the performance by the assignee of the terms of this Contract. If any assignment is made that materially alters Contractor's financial burden, Contractor's compensation shall be adjusted to give effect to any increase or decrease in Contractor's operating costs.

22. NOTICES AND PLACE OF PAYMENT:

All notices to be given with respect to this Contract unless otherwise provided for shall be given to the Contractor and to the Operator respectively at the address hereinabove shown. All sums payable hereunder to Contractor shall be payable at its address hereinabove shown unless otherwise specified herein.

23. SPECIAL PROVISIONS:

24. ACCEPTANCE OF CONTRACT:

The foregoing Contract is agreed to and accepted by Operator this _____ day of_____ ____, 19

Operator

By

Title

The foregoing Contract is accepted by the undersigned as Contractor this _____day of____, 19__, which is the effective date of this agreement, subject to rig availability, and subject to all of its terms and provisions, with the understanding that unless said Contract is thus executed by Operator within ____days of the above date, Contractor shall be in no manner bound by its signature thereto.

Contractor____________________________________

By____________________________________

Title____________________________________

[Exhibits A and B to the form contract are not included in Appendix 8.]

APPENDIX 9: A.A.P.L. FORM 610-1989 MODEL FORM OPERATING AGREEMENT

OPERATING AGREEMENT

DATED

_________________, 19___,

OPERATOR ____

CONTRACT AREA ____

____

____

COUNTY OR PARISH OF _________________, STATE OF _______

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OPERATING AGREEMENT

THIS AGREEMENT, entered into by and between ____________________________ ___________________________, hereinafter designated and referred to as "Operator", and the signatory party or parties other than Operator, sometimes hereinafter referred to individually as "Non-Operator", and collectively as "Non-Operators".

WITNESSETH:

WHEREAS, the parties to this agreement are owners of Oil and Gas Leases and/or Oil and Gas Interests in the land identified in Exhibit "A", and the parties hereto have reached an agreement to explore and develop these Leases and/or Oil and Gas Interests for the production of Oil and Gas to the extent and as hereinafter provided,

NOW, THEREFORE, it is agreed as follows:

ARTICLE I.
DEFINITIONS

As used in this agreement, the following words and terms shall have the meanings here ascribed to them:

A. The term "AFE" shall mean an Authority for Expenditure prepared by a party to this agreement for the purpose of estimating the costs to be incurred in conducting an operation hereunder.

B. The term "Completion" or "Complete" shall mean a single operation intended to complete a well as a producer of Oil and Gas in one or more Zones, including, but not limited to, the setting of production casing, perforating, well stimulation and production testing conducted in such operation.

C. The term "Contract Area" shall mean all of the lands, Oil and Gas Leases and/or Oil and Gas Interests intended to be developed and operated for Oil and Gas purposes under this agreement. Such lands, Oil and Gas Leases and Oil and Gas Interests are described in Exhibit "A".

D. The term "Deepen" shall mean a single operation whereby a well is drilled to an objective Zone below the deepest Zone in which the well was previously drilled, or below the Deepest Zone proposed in the associated AFE, whichever is the lesser.

E. The terms "Drilling Party" and "Consenting Party" shall mean a party who agrees to join in and pay its share of the cost of any operation conducted under the provisions of this agreement.

F. The term "Drilling Unit" shall mean the area fixed for the drilling of one well by order or rule of any state or federal body having authority. If a Drilling Unit is not fixed by any such rule or order, a Drilling Unit shall be the drilling unit as established by the pattern of drilling in the Contract Area unless fixed by express agreement of the Drilling Parties.

G. The term "Drillsite" shall mean the Oil and Gas Lease or Oil and Gas Interest on which a proposed well is to be located.

H. The term "Initial Well" shall mean the well required to be drilled by the parties hereto as provided in Article VI.A.

I. The term "Non-Consent Well" shall mean a well in which less than all parties have conducted an operation as provided in Article VI.B.2.

J. The terms "Non-Drilling Party" and "Non-Consenting Party" shall mean a party who elects not to participate in a proposed operation.

K. The term "Oil and Gas" shall mean oil, gas, casinghead gas, gas condensate, and/or all other liquid or gaseous hydrocarbons and other marketable substances produced therewith, unless an intent to limit the inclusiveness of this term is specifically stated.

L. The term "Oil and Gas Interests" or "Interests" shall mean unleased fee and mineral interests in Oil and Gas in tracts of land lying within the Contract Area which are owned by parties to this agreement.

M. The terms "Oil and Gas Lease", "Lease" and "Leasehold" shall mean the oil and gas leases or interests therein covering tracts of land lying within the Contract Area which are owned by the parties to this agreement.

N. The term "Plug Back" shall mean a single operation whereby a deeper Zone is abandoned in order to attempt a Completion in a shallower Zone.

O. The term "Recompletion" or "Recomplete" shall mean an operation whereby a Completion in one Zone is abandoned in order to attempt a Completion in a different Zone within the existing wellbore.

P. The term "Rework" shall mean an operation conducted in the wellbore of a well after it is Completed to secure,
restore, or improve production in a Zone which is currently open to production in the wellbore. Such operations include, but are not limited to, well stimulation operations but exclude any routine repair or maintenance work or drilling, Sidetracking, Deepening, Completing, Recompleting, or Plugging Back of a well.

Q. The term "Sidetrack" shall mean the directional control and intentional deviation of a well from vertical so as to change the bottom hole location unless done to straighten the hole or to drill around junk in the hole to overcome other mechanical difficulties.

R. The term "Zone" shall mean a stratum of earth containing or thought to contain a common accumulation of Oil and Gas separately producible from any other common accumulation of Oil and Gas.

Unless the context otherwise clearly indicates, words used in the singular include the plural, the word "person" includes natural and artificial persons, the plural includes the singular, and any gender includes the masculine, feminine, and neuter.

ARTICLE II
EXHIBITS

The following exhibits, as indicated below and attached hereto, are incorporated in and made a part hereof:

____A. Exhibit "A", shall include the following information:

(1) Description of lands subject to this agreement,

(2) Restrictions, if any, as to depths, formations, or substances,
(3) Parties to agreement with addresses and telephone numbers for notice purposes,
(4) Percentages or fractional interests of parties to this agreement,
(5) Oil and Gas Leases and/or Oil and Gas Interests subject to this agreement,
(6) Burdens on production.

____B. Exhibit "B", Form of Lease.
____C. Exhibit "C", Accounting Procedure.
____D. Exhibit "D", Insurance.
____E. Exhibit "E", Gas Balancing Agreement.
____F. Exhibit "F", Non-Discrimination and Certification of Non-Segregated Facilities.
____G. Exhibit "G", Tax Partnership.
____H. Other: ____________________________________.

If any provision of any exhibit, except Exhibits "E", "F" and "G", is inconsistent with any provision contained in the body of this agreement, the provisions in the body of this agreement shall prevail.

ARTICLE III
INTERESTS OF PARTIES

A. Oil and Gas Interests:

If any party owns an Oil and Gas Interest in the Contract Area, that Interest shall be treated for all purposes of this agreement and during the term hereof as if it were covered by the form of Oil and Gas Lease attached hereto as Exhibit "B", and the owner thereof shall be deemed to own both royalty interest in such lease and the interest of the lessee thereunder.

B. Interests of Parties in Costs and Production:

Unless changed by other provisions, all costs and liabilities incurred in operations under this agreement shall be borne and paid, and all equipment and materials acquired in operations on the Contract Area shall be owned, by the parties as their interests are set forth in Exhibit "A". In the same manner, the parties shall also own all production of Oil and Gas from the Contract Area subject, however, to the payment of royalties and other burdens on production as described hereafter.

Regardless of which party has contributed any Oil and Gas Lease or Oil and Gas Interest on which royalty or other burdens may be payable and except as otherwise expressly provided in this agreement, each party shall pay or deliver, or cause to be paid or delivered, all burdens on its share of the production from the Contract Area up to, but not in excess of, ____________________ and shall indemnify, defend and hold the other parties free from any liability therefor. Except as otherwise expressly provided in this agreement, if any party has contributed hereto any Lease or Interest which is burdened with any royalty, overriding royalty, production payment or other burden on production in excess of the amounts stipulated above, such party so burdened shall assume and alone bear all such excess obligations and shall indemnify, defend and hold the other parties hereto harmless from any and all claims attributable to such excess burden. However, so long as the Drilling Unit for the productive Zone(s) is identical with the Contract Area, each party shall pay or deliver, or cause to be paid or delivered, all burdens on production from the Contract Area due under the terms of the Oil and Gas Lease(s) which such party has contributed to this agreement, and shall indemnify, defend and hold the other parties free from any liability therefor.

No party shall ever be responsible, on a price basis higher than the price received by such party, to any other party's lessor or royalty owner, and if such party's lessor or royalty owner should demand and receive settlement on a higher price basis, the party contributing the affected Lease shall bear the additional royalty burden attributable to such higher price.

Nothing contained in this Article III.B. shall be deemed an assignment or cross-assignment of interests covered hereby, and in the event two or more parties contribute to this agreement jointly owned Leases, the parties' undivided interests in said Leaseholds shall be deemed separate leasehold interests for the purposes of this agreement.

C. Subsequently Created Interests:

If any party has contributed hereto a Lease or Interest that is burdened with an assignment of production given as security for the payment of money, or if, after the date of this agreement, any party creates an overriding royalty, production payment, net profits interest, assignment of production or other burden payable out of production attributable to its working interest hereunder, such burden shall be deemed a "Subsequently Created Interest." Further, if any party has contributed hereto a Lease or Interest burdened with an overriding royalty, production payment, net profits interest, or other burden payable out of production created prior to the date of this agreement, and such burden is not shown on Exhibit "A," such burden also shall be deemed a Subsequently Created Interest to the extent such burden causes the burdens on such party's Lease or Interest to exceed the amount stipulated in Article III.B. above.

The party whose interest is burdened with the Subsequently Created Interest (the "Burdened Party") shall assume and alone bear, pay and discharge the Subsequently Created Interest and shall indemnity, defend and hold harmless the other parties from and against any liability therefor. Further, if the Burdened Party fails to pay, when due, its share of expenses chargeable hereunder, all provisions of Article VII.B. shall be enforceable against the Subsequently Created Interest in the same manner as they are enforceable against the working interest of the Burdened Party. If the Burdened Party is required under this agreement to assign or relinquish to any other party, or parties, all or a portion of its working interest and/or the production attributable thereto, said other party, or parties, shall receive said assignment and/or production free and clear of said Subsequently Created Interest, and the Burdened Party shall indemnify, defend and hold harmless said other party, or parties, from any and all claims and demands for payment asserted by owners of the Subsequently Created Interest.

ARTICLE IV.
TITLES

A. Title Examination:

Title examination shall be made on the Drillsite of any proposed well prior to commencement of drilling operations and, if a majority in interest of the Drilling Parties so request or Operator so elects, title examination shall be made on the entire Drilling Unit, or maximum anticipated Drilling Unit, of the well. The opinion will include the ownership of the working interest, minerals, royalty, overriding royalty and production payments under the applicable Leases. Each party contributing Leases and/or Oil and Gas Interests to be included in the Drillsite or Drilling Unit, if appropriate, shall furnish to Operator all abstracts (including federal lease status reports), title opinions, title papers and curative material in its possession free of charge. All such information not in the possession of or made available to Operator by the parties, but necessary for the examination of the title, shall be obtained by Operator. Operator shall cause title to be examined by attorneys on its staff or by outside attorneys. Copies of all title opinions shall be furnished to each Drilling Party. Costs incurred by Operator in procuring abstracts, fees paid outside attorneys for title examination (including preliminary, supplemental, shut-in royalty opinions and division order title opinions) and other direct charges as provided in Exhibit "C" shall be borne by the Drilling Parties in the proportion that the interest of each Drilling Party bears to the total interest of all Drilling Parties as such interests appear in Exhibit "A". Operator shall make no charge for services rendered by its staff attorneys or other personnel in the performance of the above functions.

Each party shall be responsible for securing curative matter and pooling amendments or agreements required in connection with Leases or Oil and Gas Interests contributed by such party. Operator shall be responsible for the preparation and recording of pooling designations or declarations and communitization agreements as well as the conduct of hearings before governmental agencies for the securing of spacing or pooling orders or any other orders necessary or appropriate to the conduct of operations hereunder. This shall not prevent any party from appearing on its own behalf at such hearings. Costs incurred by Operator, including fees paid to outside attorneys, which are associated with hearings before governmental agencies, and which costs are necessary and proper for the activities contemplated under this agreement, shall be direct charges to the joint account and shall not be covered by the administrative overhead charges as provided in Exhibit "C". Operator shall make no charge for services rendered by its staff attorneys or other personnel in the performance of the above functions.

No well shall be drilled on the Contract Area until after (1) the title to the Drillsite or Drilling Unit, if appropriate, has been examined as above provided, and (2) the title has been approved by the examining attorney or title has been accepted by all of the Drilling Parties in such well.

B. Loss or Failure of Title:

1. <u>Failure of Title</u>: Should any Oil and Gas Interest or Oil and Gas Lease be lost through failure of title, which results in a reduction of interest from that shown on Exhibit "A", the party credited with contributing the affected Lease or Interest (including, if applicable, a successor in interest to such party) shall have ninety (90) days from final determination of title failure to acquire a new lease or other instrument curing the entirety

of the title failure, which acquisition will not be subject to Article VIII.B., and failing to do so, this agreement, nevertheless, shall continue in force as to all remaining Oil and Gas Leases and Interests; and,

(a) The party credited with contributing the Oil and Gas Lease or Interest affected by the title failure (including, if applicable, a successor in interest to such party) shall bear alone the entire loss and it shall not be entitled to recover from Operator or the other parties any development or operating costs which it may have previously paid or incurred, but there shall be no additional liability on its part to the other parties hereto by reason of such title failure;

(b) There shall be no retroactive adjustment of expenses incurred or revenues received from the operation of the Lease or Interest which has failed, but the interests of the parties contained on Exhibit "A" shall be revised on an acreage basis, as of the time it is determined finally that title failure has occurred, so that the interest of the party whose Lease or Interest is affected by the title failure will thereafter be reduced in the Contact Area by the amount of the Lease or Interest failed;

(c) If the proportionate interest of the other parties hereto in any producing well previously drilled on the Contract Area is increased by reason of the title failure, the party who bore the costs incurred in connection with such well attributable to the Lease or Interest which has failed shall receive the proceeds attributable to the increase in such interest (less costs and burdens attributable thereto) until it has been reimbursed for unrecovered costs paid by it in connection with such well attributable to such failed Lease or Interest;

(d) Should any person not a party to this agreement, who is determined to be the owner of any Lease or Interest which has failed, pay in any manner any part of the cost of operation, development, or equipment, such amount shall be paid to the party or parties who bore the costs which are so refunded;

(e) Any liability to account to a person not a party to this agreement for prior production of Oil and Gas which arises by reason of title failure shall be borne severally by each party (including a predecessor to a current party) who received production for which such accounting is required based on the amount of such production received, and each such party shall severally indemnify, defend and hold harmless all other parties hereto for any such liability to account;

(f) No charge shall be made to the joint account for legal expenses, fees or salaries in connection with the defense of the Lease or Interest claimed to have failed, but it the party contributing such Lease or Interest hereto elects to defend its title it shall bear all expenses in connection therewith; and

(g) If any party is given credit on Exhibit "A" to a Lease or Interest which is limited solely to ownership of an interest in the wellbore of any well or wells and the production therefrom, such party's absence of interest in the remainder of the Contract Area shall be considered a Failure of Title as to such remaining Contract Area unless that absence of interest is reflected on Exhibit "A".

2. <u>Loss by Non-Payment or Erroneous Payment of Amount Due</u>: If, through mistake or oversight, any rental, shut-in well payment, minimum royalty or royalty payment, or other payment necessary to maintain all or a portion of an Oil and Gas Lease or Interest is not paid or is erroneously paid, and as a result a Lease or Interest terminates, there shall be no monetary liability against the party who failed to make such payment. Unless the party who failed to make the required payment secures a new Lease or Interest covering the same interest within ninety (90) days from the discovery of the failure to

make proper payment, which acquisition will not be subject to Article VIII.B., the interests of the parties reflected on Exhibit “A” shall be revised on an acreage basis, effective as of the date of termination of the Lease or Interest involved, and the party who failed to make proper payment will no longer be credited with an interest in the Contract Area on account of ownership of the Lease or Interest which has terminated. If the party who failed to make the required payment shall not have been fully reimbursed, at the time of the loss, from the proceeds of the sale of Oil and Gas attributable to the lost Lease or Interest, calculated on an acreage basis, for the development and operating costs previously paid on account of such Lease or Interest, it shall be reimbursed for unrecovered actual costs previously paid by it (but not for its share of the cost of any dry hole previously drilled or wells previously abandoned) from so much of the following as is necessary to effect reimbursement:

(a) Proceeds of Oil and Gas produced prior to termination of the Lease or Interest, less operating expenses and lease burdens chargeable hereunder to the person who failed to make payment, previously accrued to the credit of the Lost Lease or Interest, on an acreage basis, up to the amount of unrecovered costs;

(b) Proceeds of Oil and Gas, less operating expenses and lease burdens chargeable hereunder to the person who failed to make payment, up to the amount of unrecovered costs attributable to that portion of Oil and Gas thereafter produced and marketed (excluding production from any wells thereafter drilled) which, in the absence of such Lease or Interest termination, would be attributable to the lost Lease or Interest on an acreage basis and which as a result of such Lease or Interest termination is credited to other parties, the proceeds of said portion of the Oil and Gas to be contributed by the other parties in proportion to their respective interests reflected on Exhibit "A"; and,

(c) Any monies, up to the amount of unrecovered costs, that may be paid by any party who is, or becomes, the owner of the Lease or Interest lost, for the privilege of participating in the Contract Area or becoming a party to this agreement.

3. Other Losses: All losses of Leases or Interests committed to this agreement, other than those set forth in Articles IV.B.1. and IV.B.2. above, shall be joint losses and shall be borne by all parties in proportion to their interests shown on Exhibit "A". This shall include but not be limited to the loss of any Lease or Interest through failure to develop or because express or implied covenants have not been performed (other than performance which requires only the payment of money), and the loss of any Lease by expiration at the end of its primary term if it is not renewed or extended. There shall be no readjustment of interests in the remaining portion of the Contract Area on account of any joint loss.

4. Curing Title: In the event of a Failure of Title under Article IV.B.1. or a loss of title under Article IV.B.2. above, any Lease or Interest acquired by any party hereto (other than the party whose interest has failed or was lost) during the ninety (90) day period provided by Article IV.B.1. and Article IV.B.2. above covering all or a portion of the interest that has failed or was lost shall be offered at cost to the party whose interest has failed or was lost, and the provisions of Article VIII.B. shall not apply to such acquisition.

ARTICLE V.
OPERATOR

A. Designation and Responsibilities of Operator:

______________________ shall be the Operator of the Contract Area, and shall conduct and direct and have full control of all operations on the Contract Area as permitted and required by, and within the limits of this agreement. In its performance of services hereunder for the Non-Operators, Operator shall be an independent contractor not subject to the control or direction of the Non-Operators except as to the type of operation to be undertaken in accordance with the election procedures contained in this agreement. Operator shall not be deemed, or hold itself out as, the agent of the Non-Operators with authority to bind them to any obligation or liability assumed or incurred by Operator as to any third party. Operator shall conduct its activities under this agreement as a reasonable prudent operator, in a good and workmanlike manner, with due diligence and dispatch, in accordance with good oilfield practice, and in compliance with applicable law and regulation, but in no event shall it have any liability as Operator to the other parties for losses sustained or liabilities incurred except such as may result from gross negligence or willful misconduct.

B. Resignation or Removal of Operator and Selection of Successor:

1. Resignation or Removal of Operator: Operator may resign at any time by giving written notice thereof to Non-Operators. If Operator terminates its legal existence, no longer owns an interest hereunder in the Contract Area, or is no longer capable of serving as Operator, Operator shall be deemed to have resigned without any action by Non-Operators, except the selection of a successor. Operator may be removed only for good cause by the affirmative vote of Non-Operators owning a majority interest based on ownership as shown on Exhibit "A" remaining after excluding the voting interest of Operator; such vote shall not be deemed effective until a written notice has been delivered to the Operator by a Non-Operator detailing the alleged default and Operator has failed to cure the default within thirty (30) days from its receipt of the notice or, if the default concerns an operation then being conducted, within forty-eight (48) hours of its receipt of the notice. For purposes hereof, "good cause" shall mean not only gross negligence or willful misconduct but also the material breach of or inability to meet the standards of operation contained in Article V.A. or material failure or inability to perform its obligations under this agreement.

Subject to Article VII.D.1., such resignation or removal shall not become effective until 7:00 o'clock A.M. on the first day of the calendar month following the expiration of ninety (90) days after the giving of notice of resignation by Operator or action by the Non-Operators to remove Operator, unless a successor Operator has been selected and assumes the duties of Operator at an earlier date. Operator, after effective date of resignation or removal, shall be bound by the terms hereof as a Non-Operator. A change of a corporate name or structure of Operator or transfer of Operator's interest to any single subsidiary, parent or successor corporation shall not be the basis for removal of Operator.

2. Selection of Successor Operator: Upon the resignation or removal of Operator under any provision of this agreement, a successor Operator shall be selected by the parties. The successor Operator shall be selected from the parties owning an interest in the Contract Area at the time such successor Operator is selected. The successor
Operator shall be selected by the affirmative vote of two (2) or more parties owning a

majority interest based on ownership as shown on Exhibit "A"; provided, however, if an Operator which has been removed or is deemed to have resigned fails to vote or votes only to succeed itself, the successor Operator shall be selected by the affirmative vote of the party or parties owning a majority interest based on ownership as shown in Exhibit "A" remaining after excluding the voting interest of the Operator that was removed or resigned. The former Operator shall promptly deliver to the successor Operator all records and data relating to the Operations conducted by the former Operator to the extent such records and data are not already in the possession of the successor Operator. Any cost of obtaining or copying the former Operator's records and data shall be charged to the joint account.

3. Effect of Bankruptcy: If Operator becomes insolvent, bankrupt or is placed in receivership, it shall be deemed to have resigned without any action by Non-Operators, except the selection of a successor. If a petition for relief under the federal bankruptcy laws is filed by or against Operator, and the removal of Operator is prevented by the federal bankruptcy court, all Non-Operators and Operator shall comprise an interim operating committee to serve until Operator has elected to reject or assume this agreement pursuant to the Bankruptcy Code, and an election to reject this agreement by Operator as a debtor in possession, or by a trustee in bankruptcy, shall be deemed a resignation as Operator without any action by Non-Operators, except the selection of a successor. During the period of time the operating committee controls operations, all actions shall require the approval of two (2) or more parties owning a majority interest based on ownership as shown on Exhibit "A". In the event there are only two (2) parties to this agreement, during the period of time the operating committee controls operations, a third party acceptable to Operator, Non-Operator and the federal bankruptcy court shall be selected as a member of the operating committee, and all actions shall require the approval of two (2) members of the operating committee without regard for their interest in the Contract Area based on Exhibit "A".

C. Employees and Contractors:

The number of employees or contractors used by Operator in conducting operations hereunder, their selection, and the hours of labor and the compensation for services performed shall be determined by Operator, and all such employees or contractors shall be the employees or contractors of Operator.

D. Rights and Duties of Operator:

1. Competitive Rates and Use of Affiliates: All wells drilled on the Contract Area shall be drilled on a competitive contract basis at the usual rates prevailing in the area. If it so desires, Operator may employ its own tools and equipment in the drilling of wells, but its charges therefor shall not exceed the prevailing rates in the area and the rate of such charges shall be agreed upon by the parties in writing before drilling operations are commenced, and such work shall be performed by Operator under the same terms and conditions as are customary and usual in the area in contracts of independent contractors who are doing work of a similar nature. All work performed or materials supplied by affiliates or related parties of Operator shall be performed or supplied at competitive rates, pursuant to written agreement, and in accordance with customs and standards prevailing in the industry.

2. Discharge of Joint Account Obligations: Except as herein otherwise specifically provided, Operator shall promptly pay and discharge expenses incurred in the development and operation of the Contract Area pursuant to this agreement and shall charge each of the parties hereto with their respective proportionate shares upon the

expense basis provided in Exhibit "C". Operator shall keep an accurate record of the joint account hereunder, showing expenses incurred and charges and credits made and received.

3. Protection from Liens: Operator shall pay, or cause to be paid, as and when they become due and payable, all accounts of contractors and suppliers and wages and salaries for services rendered or performed, and for materials supplied on, to or in respect of the Contract Area or any operations for the joint account thereof, and shall keep the Contract Area free from liens and encumbrances resulting therefrom except for those resulting from a bona fide dispute as to services rendered or materials supplied.

4. Custody of Funds: Operator shall hold for the account of the Non-Operators any funds of the Non-Operators advanced or paid to the Operator, either for the conduct of operations hereunder or as a result of the sale of production from the Contract Area, and such funds shall remain the funds of the Non-Operators on whose account they are advanced or paid until used for their intended purpose or otherwise delivered to the Non-Operators or applied toward the payment of debts as provided in Article VII.B. Nothing in this paragraph shall be construed to establish a fiduciary relationship between Operator and Non-Operators for any purpose other than to account for Non-Operator funds as herein specifically provided. Nothing in this paragraph shall require the maintenance by Operator of separate accounts for the funds of Non-Operators unless the parties otherwise specifically agree.

5. Access to Contract Area and Records: Operator shall, except as otherwise provided herein, permit each Non-Operator or its duly authorized representative, at the Non-Operator's sole risk and cost, full and free access at all reasonable times to all operations of every kind and character being conducted for the joint account on the Contract Area and to the records of operations conducted thereon or production therefrom, including Operator's books and records relating thereto. Such access rights shall not be exercised in a manner interfering with Operator's conduct of an operation hereunder and shall not obligate the Operator to furnish any geologic or geophysical data of an interpretive nature unless the cost of preparation of such interpretive data was charged to the joint account. Operator will furnish to each Non-Operator upon request copies of any and all reports and information obtained by Operator in connection with production and related items, including, without limitation, meter and chart reports, production purchaser statements, run tickets and monthly gauge reports, but excluding purchase contracts and pricing information to the extent not applicable to the production of the Non-Operator seeking the information. Any audit of Operator's records relating to amounts expended and the appropriateness of such expenditures shall be conducted in accordance with the audit protocol specified in Exhibit "C".

6. Filing and Furnishing Governmental Reports: Operator will file, and upon written request promptly furnish copies to each requesting Non-Operator not in default of its payment obligations, all operational notices, reports or applications required to be filed by local, State, Federal or Indian agencies or authorities having jurisdiction over operations hereunder. Each Non-Operator shall provide to Operator on a timely basis all information necessary to Operator to make such filings.

7. Drilling and Testing Operations: The following provisions shall apply to each well drilled hereunder, including but not limited to the Initial Well:

(a) Operator will promptly advise Non-Operators of the date on which the well is spudded, or the date on which drilling operations are commenced.

(b) Operator will send to Non-Operators such reports, test results and notices regarding the progress of operations on the well as the Non-Operators shall reasonably request, including, but not limited to, daily drilling reports, completion reports, and well logs.

(c) Operator shall adequately test all Zones encountered which may reasonably be expected to be capable of producing Oil and Gas in paying quantities as a result of examination of the electric log or any other logs or cores or tests conducted hereunder.

8. Cost Estimates. Upon request of any Consenting Party, Operator shall furnish estimates of current and cumulative costs incurred for the joint account at reasonable intervals during the conduct of any operation pursuant to this agreement. Operator shall not be held liable for errors in such estimates so long as the estimates are made in good faith.

9. Insurance: At all times while operations are conducted hereunder, Operator shall comply with the workers compensation law of the state where the operations are being conducted; provided, however, that Operator may be a self-insurer for liability under said compensation laws in which event the only charge that shall be made to the joint account shall be as provided in Exhibit "C". Operator shall also carry or provide insurance for the benefit of the joint account of the parties as outlined in Exhibit "D" attached hereto and made a part hereof. Operator shall require all contractors engaged in work on or for the Contract Area to comply with the workers compensation law of the state where the operations are being conducted and to maintain such other insurance as Operator may require.

In the event automobile liability insurance is specified in said Exhibit "D", or subsequently receives the approval of the parties, no direct charge shall be made by Operator for premiums paid for such insurance for Operator's automotive equipment.

ARTICLE VI.
DRILLING AND DEVELOPMENT

A. Initial Well:

On or before the __ day of ________, 19__, Operator shall commence the drilling of the Initial Well at the following location:

and shall thereafter continue the drilling of the well with due diligence to

The drilling of the Initial Well and the participation therein by all parties is obligatory, subject to Article VI.C.1. as to participation in Completion operations and Article VI.F. as to termination of operations and Article XI as to occurrence of *force majeure*.

B. Subsequent Operations:

1. Proposed Operations: If any party hereto should desire to drill any well on the Contract Area other than the Initial Well, or if any party should desire to Rework, Sidetrack, Deepen, Recomplete, or Plug Back a dry hole or a well no longer capable of producing in paying quantities in which such party has not otherwise relinquished its interest in the proposed objective Zone under this agreement, the party desiring to drill, Rework, Sidetrack, Deepen, Recomplete, or Plug Back such a well shall give written notice of the proposed operation to the parties who have not otherwise relinquished their interest in such objective Zone under this agreement and to all other parties in the case of a proposal for Sidetracking or Deepening, specifying the work to be performed, the location, proposed depth, objective Zone and the estimated cost of the operation. The parties to whom such a notice is delivered shall have thirty (30) days after receipt of the notice within which to notify the party proposing to do the work whether they elect to participate in the cost of the proposed operation. If a drilling rig is on location, notice of a proposal to Rework, Sidetrack, Recomplete, Plug Back or Deepen may be given by telephone and the response period shall be limited to forty-eight (48) hours, exclusive of Saturday, Sunday and legal holidays. Failure of a party to whom such notice is delivered to reply within the period above fixed shall constitute an election by that party not to participate in the cost of the proposed operation. Any proposal by a party to conduct an operation conflicting with the operation initially proposed shall be delivered to all parties within the time and in the manner provided in Article VI.B.6.

If all parties to whom such notice is delivered elect to participate in such a proposed operation, the parties shall be contractually committed to participate therein provided such operations are commenced within the time period hereafter set forth, and Operator shall, no later than ninety (90) days after expiration of the notice period of thirty (30) days (or as promptly as practicable after the expiration of the forty-eight (48) hour period when a drilling rig is on location, as the case may be), actually commence the proposed operation and thereafter complete it with due diligence at the risk and expense of the parties participating therein; provided, however, said commencement date may be extended upon written notice of same by Operator to the other parties, for a period of up to thirty (30) additional days if in the sole opinion of Operator, such additional time is reasonably necessary to obtain permits from governmental authorities, surface rights (including rights-of-way) or appropriate drilling equipment, or to complete title examination or curative matter required for title approval or acceptance. If the actual operation has not been commenced within the time provided (including any extension thereof as specifically permitted herein or in the force majeure provisions of Article XI) and if any party hereto still desires to conduct said operation, written notice proposing same must be resubmitted to the other parties in accordance hereof as if no prior proposal had been made. Those parties that did not participate in the drilling of a well for which a proposal to Deepen or Sidetrack is made hereunder shall, if such parties desire to participate in the proposed Deepening or Sidetracking operation, reimburse the Drilling Parties in accordance with Article VI.B.4. in the event of a Deepening operation and in accordance with Article VI.B.5. in the event of a Sidetracking operation.

2. Operations by Less Than All Parties:

(a) Determination of Participation. If any party to whom such notice is delivered as provided in Article VI.B.1. or VI.C.1. (Option No. 2) elects not to participate in the proposed operation, then, in order to be entitled to the benefits of this Article, the party or parties giving the notice and such other parties as shall elect to participate in the operation shall, no later than ninety (90) days after the expiration of the notice period of thirty (30) days (or as promptly as practicable after the expiration of the forty-eight (48) hour period when a drilling rig is on location, as the case may be) actually commence the proposed operation and complete it with due diligence. Operator shall perform all work for the account of the Consenting Parties; provided, however, if no drilling rig or other equipment is on location, and if Operator is a Non-Consenting Party, the Consenting Parties shall either: (i) request Operator to perform the work required by such proposed operation for the account of the Consenting Parties, or (ii) designate one of the Consenting Parties as Operator to perform such work. The rights and duties granted to and imposed upon the Operator under this agreement are granted to and imposed upon the party designated as Operator for an operation in which the original Operator is a Non-Consenting Party. Consenting Parties, when conducting operations on the Contract Area pursuant to this Article VI.B.2., shall comply with all terms and conditions of this agreement.

If less than all parties approve any proposed operation, the proposing party, immediately after the expiration of the applicable notice period, shall advise all Parties of the total interest of the parties approving such operation and its recommendation as to whether the Consenting Parties should proceed with the operation as proposed. Each Consenting Party, within forty-eight (48) hours (exclusive of Saturday, Sunday and legal holidays) after delivery of such notice, shall advise the proposing party of its desire to (i) limit participation to such party's interest as shown on Exhibit "A" or (ii) carry only its proportionate part (determined by dividing such party's interest in the Contract Area by the interests of all Consenting Parties in the Contract Area) of Non-Consenting Parties' interests, or (iii) carry its proportionate part (determined as provided in (ii)) of Non-Consenting Parties' interests together with all or a portion of its proportionate part of any Non-Consenting Parties' interests that any Consenting Party did not elect to take. Any interest of Non-Consenting Parties that is not carried by a Consenting Party shall be deemed to be carried by the party proposing the operation if such party does not withdraw its proposal. Failure to advise the proposing party within the time required shall be deemed an election under (i). In the event a drilling rig is on location, notice may be given by telephone, and the time permitted for such a response shall not exceed a total of forty-eight (48) hours (exclusive of Saturday, Sunday and legal holidays). The proposing party, at its election, may withdraw such proposal it there is less than 100% participation and shall notify all parties of such decision within ten (10) days, or within twenty-four (24) hours if a drilling rig is on location, following expiration of the applicable response period. If 100% subscription to the proposed operation is obtained, the proposing party shall promptly notify the consenting parties of their proportionate interests in the operation and the party serving as Operator shall commence such operation within the period provided in Article VI.B.1., subject to the same extension right as provided therein.

(b) Relinquishment of Interest for Non-Participation. The entire cost and risk of conducting such operations shall be borne by the Consenting Parties in the proportions they have elected to bear same under the terms of the preceding paragraph. Consenting Parties shall keep the leasehold estates involved in such operations free and clear of all liens and encumbrances of every kind created by or arising from the operations of the

Consenting Parties. If such an operation results in a dry hole, then subject to Articles VI.B.6. and VI.E.3., the Consenting Parties shall plug and abandon the well and restore the surface location at their sole cost, risk and expense; provided, however, that those Non-Consenting Parties that participated in the drilling, Deepening or Sidetracking of the well shall remain liable for, and shall pay, their proportionate shares of the cost of plugging and abandoning the well and restoring the surface location insofar only as those costs were not increased by the subsequent operations of the Consenting Parties. If any well drilled, Reworked, Sidetracked, Deepened, Recompleted, or Plugged Back under the provisions of this Article results in a well capable of producing Oil and/or Gas in paying quantities, the Consenting Parties shall Complete and equip the well to produce at their sole cost and risk, and the well shall then be turned over to Operator (if the Operator did not conduct the operation) and shall be operated by it at the expense and for the account of the Consenting Parties. Upon commencement of operations for the drilling, Reworking, Sidetracking, Recompleting, Deepening or Plugging Back of any such well by Consenting Parties in accordance with the provisions of this Article, each Consenting Party shall be deemed to have relinquished to Consenting Parties, and Non-Consenting Parties shall own and be entitled to receive, in proportion to their respective interests, all of such Non-Consenting Party's interest in the well and share of production therefrom or, in the case of a Reworking, Sidetracking, Deepening, Recompleting or Plugging Back, or a Completion pursuant to Article VI.C. Option No. 2, all of such Non-Consenting Party's interest in the production obtained from the operation in which the Non-Consenting Party did not elect to participate. Such relinquishment shall be effective until the proceeds of the sale of such share, calculated at the well, or market value thereof if such share is not sold (after deducting applicable ad valorem, production, severance, and excise taxes, royalty, overriding royalty and other interests not excepted by Article III.C. payable out of or measured by the production from such well accruing with respect to such interest until it reverts), shall equal the total of the following:

(i) ___% of each such Non-Consenting Party's share of the cost of any newly acquired surface equipment beyond the wellhead connections (including but not limited to stock tanks, separators, treaters, pumping equipment and piping), plus 100% of each such Non-Consenting Party's share of the cost of operation of the well commencing with first production and continuing until each such Non-Consenting Party's relinquished interest shall revert to it under other provisions of this Article, it being agreed that each Non-Consenting Party's share of such costs and equipment will be that interest which would have been chargeable to such Non-Consenting Party had it participated in the well from the beginning of the operations; and

(ii) ___% of (a) that portion of the costs and expenses of drilling, Reworking, Sidetracking, Deepening Plugging Back, testing, Completing, and Recompleting after deducting any cash contributions received under Article VIII.C., and of (b) that portion of the cost of newly acquired equipment in the well (to and including the wellhead connections), which would have been chargeable to such Non-Consenting Party if it had participated therein.

Notwithstanding anything to the contrary in this Article VI.B., if the well does not reach the deepest objective Zone described in the notice proposing the well for reasons other than the encountering of granite or practically impenetrable substance or other condition in the hole rendering further operations impracticable, Operator shall give notice thereof to each Non-Consenting Party who submitted or voted for an alternative proposal under Article VI.B.6. to drill the well to a shallower Zone than the deepest objective Zone proposed in the notice under which the well was drilled, and each such

Non-Consenting Party shall have the option to participate in the initial proposed Completion of the well by paying its share of the cost of drilling the well to its actual depth, calculated in the manner provided in Article VI.B.4.(a). If any such Non-Consenting Party does not elect to participate in the first Completion proposed for such well, the relinquishment provisions of this Article VI.B.2.(b) shall apply to such party's interest.

(c) Reworking, Recompleting, or Plugging Back. An election not to participate in the drilling, Sidetracking or Deepening of a well shall be deemed an election not to participate in any Reworking or Plugging Back operation proposed in such a well, or portion thereof, to which the initial non-consent election applied that is conducted at any time prior to full recovery by the Consenting Parties of the Non-Consenting Party's recoupment account. Similarly, an election not to participate in the Completing or Recompleting of a well shall be deemed an election not to participate in any Reworking operation proposed in such a well, or portion thereof, to which the initial non-consent election applied that is conducted at any time prior to full recovery by the Consenting Parties of the Non-Consenting Party's recoupment amount. Any such Reworking, Recompleting or Plugging Back operation conducted during the recoupment period shall be deemed part of the cost of operation of said well and there shall be added to the sums to be recouped by the Consenting Parties _____% of that portion of the costs of the Reworking, Recompleting, or Plugging Back operation which would have been chargeable to such Non-Consenting Party had it participated therein. If such a Reworking, Recompleting, or Plugging Back operation is proposed during such recoupment period, the provisions of this Article VI.B. shall be applicable as between said Consenting Parties in said well.

(d) Recoupment Matters. During the period of time Consenting Parties are entitled to receive Non-Consenting Party's share of production, or the proceeds therefrom, Consenting Parties shall be responsible for the payment of all ad valorem, production, severance, excise, gathering and other taxes, and all royalty, overriding royalty and other burdens applicable to Non-Consenting Party's share of production not excepted by Article III.C.

In the case of any Reworking, Sidetracking, Plugging Back, Recompleting or Deepening operation, the Consenting Parties shall be permitted to use, free of cost, all casing, tubing and other equipment in the well, but the ownership of all such equipment shall remain unchanged; and upon abandonment of a well after such Reworking, Sidetracking, Plugging Back, Recompleting or Deepening, the Consenting Parties shall account for all such equipment to the owners thereof, with each party receiving its proportionate part in kind or in value, less cost of salvage.

Within ninety (90) days after the completion of any operation under this Article, the party conducting the operations for the Consenting Parties shall furnish each Non-Consenting Party with an inventory of the equipment in and connected to the well, and itemized statement of the cost of drilling, Sidetracking, Deepening, Plugging Back, testing, Completing, Recompleting and equipping the well for production; or, at its option, the operating party, in lieu of an itemized statement of such costs of operation, may submit a detailed statement of monthly billings. Each month thereafter, during the time the Consenting Parties are being reimbursed as provided above, the party conducting the operations for the Consenting Parties shall furnish the Non-Consenting Parties with an itemized statement of all costs and liabilities incurred in the operation of the well, together with a statement of the quantity of Oil and Gas produced from it and the amount of proceeds realized from the sale of the well's working interest production during the preceding month. In determining the quantity of Oil and Gas produced during any month, Consenting Parties shall use industry accepted methods such as but not limited to metering or periodic well tests. Any amount realized from the sale or other disposition of equipment newly acquired in connection with any such operation which would have been owned by a Non-Consenting Party had it participated therein shall be credited against the total unreturned costs of the work done and of the equipment purchased in determining when the interest of such Non-Consenting Party shall revert to it as above provided; and if there is a credit balance, it shall be paid to such Non-Consenting Party.

If and when the Consenting Parties recover from a Non-Consenting Party's relinquished interest the amounts provided for above, the relinquished interests of such Non-Consenting Party shall automatically revert to it as of 7:00 a.m. on the day following the day on which such recoupment occurs, and, from and after such reversion, such Non-Consenting Party shall own the same interest in such well, the material and equipment in or pertaining thereto, and the production therefrom as such Non-Consenting Party would have been entitled to had it participated in the drilling, Sidetracking, Reworking, Deepening, Recompleting or Plugging Back of said well. Thereafter, such Non-Consenting Party shall be charged with and shall pay its proportionate part of the further costs of the operation of said well in accordance with the terms of this agreement and Exhibit "C" attached hereto.

3. Stand-By Costs: When a well which has been drilled or Deepened has reached its authorized depth and all tests have been completed and the results thereof furnished to the parties, or when operations on the well have been otherwise terminated pursuant to Article VI.G., stand-by costs incurred pending response to a party's notice proposing a Reworking, Sidetracking, Deepening, Recompleting, Plugging Back or Completing operation in such a well (including the period required under Article VI.B.6. to resolve competing proposals) shall be charged and borne as part of the drilling or Deepening operation just completed. Stand-by costs subsequent to all parties responding, or expiration of the response time permitted, whichever first occurs, and prior to agreement as to the participating interests of all Consenting Parties pursuant to the terms of the second grammatical paragraph of Article VI.B.2.(a), shall be charged to and borne as part of the proposed operation, but if the proposal is subsequently withdrawn because of insufficient participation, such stand-by costs shall be allocated between the Consenting Parties in the proportion each Consenting Party's interest as shown on Exhibit "A" bears to the total interest as shown on Exhibit "A" of all Consenting Parties.

In the event that notice for a Sidetracking operation is given while the drilling rig to be utilized is on location, any party may request and receive up to five (5) additional days after expiration of the forty-eight hour response period specified in Article VI.B.1. within which to respond by paying for all stand-by costs and other costs incurred during such extended response period; Operator may require such party to pay the estimated stand-by time in advance as a condition to extending the response period. If more than one party elects to take such additional time to respond to the notice, stand-by costs shall be allocated between the parties taking additional time to respond on a day-to-day basis in the proportion each electing party's interest as shown on Exhibit "A" bears to the total interest as shown on Exhibit "A" of all the electing parties.

4. Deepening: If less than all the parties elect to participate in a drilling, Sidetracking, or Deepening operation proposed pursuant to Article VI.B.1., the interest relinquished by the Non-Consenting Parties to the Consenting Parties under Article VI.B.2. shall relate only and be limited to the lesser of (i) the total depth actually drilled or (ii) the objective depth or Zone of which the parties were given notice under Article VI.B.1. ("Initial Objective"). Such well shall not be Deepened beyond the Initial

Objective without first complying with this Article to afford the Non-Consenting Parties the opportunity to participate in the Deepening operation.

In the event any Consenting Party desires to drill or Deepen a Non-Consent Well to a depth below the Initial Objective, such party shall give notice thereof, complying with the requirements of Article VI.B.1., to all parties (including Non-Consenting Parties). Thereupon, Articles VI.B.1. and 2. shall apply and all parties receiving such notice shall have the right to participate or not participate in the Deepening of such well pursuant to said Articles VI.B.1. and 2. If a Deepening operation is approved pursuant to such provisions, and if any Non-Consenting Party elects to participate in the Deepening operation, such Non-Consenting party shall pay or make reimbursement (as the case may be) of the following costs and expenses:

(a) If the proposal to Deepen is made prior to the Completion of such well as a well capable of producing in paying quantities, such Non-Consenting Party shall pay (or reimburse Consenting Parties for, as the case may be) that share of costs and expenses incurred in connection with the drilling of said well from the surface to the Initial Objective which Non-Consenting Party would have paid had such Non-Consenting Party agreed to participate therein, plus the Non-Consenting Party's share of the cost of Deepening and of participating in any further operations on the well in accordance with the other provisions of this Agreement; provided, however, all costs for testing and Completion or attempted Completion of the well incurred by Consenting Parties prior to the point of actual operations to Deepen beyond the Initial Objective shall be for the sole account of Consenting Parties.

(b) If the proposal is made for a Non-Consent Well that has been previously Completed as a well capable of producing in paying quantities, but is no longer capable of producing in paying quantities, such Non-Consenting Party shall pay (or reimburse Consenting Parties for, as the case may be) its proportionate share of all costs of drilling, Completing, and equipping said well from the surface to the Initial Objective, calculated in the manner provided in paragraph (a) above, less those costs recouped by the Consenting Parties from the sale of production from the well. The Non-Consenting Party shall also pay its proportionate share of all costs of re-entering said well. The Non-Consenting Parties' proportionate part (based on the percentage of such well Non-Consenting Party would have owned had it previously participated in such Non-Consent Well) of the costs of salvable materials and equipment remaining in the hole and salvable surface equipment used in connection with such well, shall be determined in accordance with Exhibit "C". If the Consenting Parties have recouped the cost of drilling, Completing, and equipping the well at the time such Deepening operation is conducted, then a Non-Consenting Party may participate in the Deepening of the well with no payment for costs incurred prior to re-entering the well for Deepening.

The foregoing shall not imply a right of any Consenting Party to propose any Deepening for a Non-Consent Well prior to the drilling of such well to its Initial Objective without the consent of the other Consenting Parties as provided in Article VI.F.

5. <u>Sidetracking</u>: Any party having the right to participate in a proposed Sidetracking operation that does not own an interest in the affected wellbore at the time of the notice shall, upon electing to participate, tender to the wellbore owners its proportionate share (equal to its interest in the Sidetracking operation) of the value of that portion of the existing wellbore to be utilized as follows:

(a) If the proposal is for Sidetracking an existing dry hole, reimbursement shall be on the basis of the actual costs incurred in the initial drilling of the well down to the depth at which the Sidetracking operation is initiated.

(b) If the proposal is for Sidetracking a well which has previously produced, reimbursement shall be on the basis of such party's proportionate share of drilling and equipping costs incurred in the initial drilling of the well down to the depth at which the Sidetracking operation is conducted, calculated in the manner described in Article VI.B.4.(b) above. Such party's proportionate share of the cost of the well's salvable materials and equipment down to the depth at which the Sidetracking operation is initiated shall be determined in accordance with the provisions of Exhibit "C".

6, Order of Preference of Operations. Except as otherwise specifically provided in this agreement, if any party desires to propose the conduct of an operation that conflicts with a proposal that has been made by a party under this Article VI, such party shall have fifteen (15) days from delivery of the initial proposal, in the case of a proposal to drill a well or to perform an operation on a well where no drilling rig is on location, or twenty-four (24) hours, exclusive of Saturday, Sunday and legal holidays, from delivery of the initial proposal, if a drilling rig is on location for the well on which such operation is to be conducted, to deliver to all parties entitled to participate in the proposed operation such party's alternative proposal, such alternate proposal to contain the same information required to be included in the initial proposal. Each party receiving such proposals shall elect by delivery of notice to Operator within five (5) days after expiration of the proposal period, or within twenty-four (24) hours (exclusive of Saturday, Sunday and legal holidays) if a drilling rig is on location for the well that is the subject of the proposals, to participate in one of the competing proposals. Any party not electing within the time required shall be deemed not to have voted. The proposal receiving the vote of parties owning the largest aggregate percentage interest of the parties voting shall have priority over all other completing proposals; in the case of a tie vote, the initial proposal shall prevail. Operator shall deliver notice of such result to all parties entitled to participate in the operation within five (5) days after expiration of the election period (or within twenty-four (24) hours, exclusive of Saturday, Sunday and legal holidays, if a drilling rig is on location.) Each party shall then have two (2) days (or twenty-four (24) hours if a rig is on location) from receipt of such notice to elect by delivery of notice to Operator to participate in such operation or to relinquish interest in the affected well pursuant to the provisions of Article VI.B.2.; failure by a party to deliver notice within such period shall be deemed an election not to participate in the prevailing proposal.

7. Conformity to Spacing Pattern. Notwithstanding the provisions of this Article VI.B.2., it is agreed that no wells shall be proposed to be drilled to or Completed in or produced from a Zone from which a well located elsewhere on the Contract Area is producing, unless such well conforms to the then-existing well spacing pattern for such Zone.

8. Paying Wells. No party shall conduct any Reworking, Deepening, Plugging Back, Completion, Recompletion, or Sidetracking operation under this agreement with respect to any well then capable of producing in paying quantities except with the consent of all parties that have not relinquished interests in the well at the time of such operation.

C. Completion of Wells; Reworking and Plugging Back:

1. Completion: Without the consent of all parties, no well shall be drilled, Deepened or Sidetracked, except any well drilled, Deepened or Sidetracked pursuant to the provisions of Article VI.B.2. of this agreement. Consent to the drilling, Deepening or Sidetracking shall include:

Option No. 1: All necessary expenditures for the drilling, Deepening or Sidetracking, testing, Completing and equipping of the well, including necessary tankage and/or surface facilities.

Option No. 2: All necessary expenditures for the drilling, Deepening or Sidetracking and testing of the well. When such well has reached its authorized depth, and all logs, cores and other tests have been completed, and the results thereof furnished to the parties, Operator shall give immediate notice to the Non-Operators having the right to participate in a Completion attempt whether or not Operator recommends attempting to Complete the well, together with Operator's AFE for Completion costs if not previously provided. The parties receiving such notice shall have forty-eight (48) hours (exclusive of Saturday, Sunday and legal holidays) in which to elect by delivery of notice to Operator to participate in a recommended Completion attempt or to make a Completion proposal with an accompanying AFE. Operator shall deliver any such Completion proposal, or any Completion proposal conflicting with Operator's proposal, to the other parties entitled to participate in such Completion in accordance with the procedures specified in Article VI.B.6. Election to participate in a Completion attempt shall include consent to all necessary expenditures for the Completing and equipping of such well, including necessary tankage and/or surface facilities but excluding any stimulation operation not contained on the Completion AFE. Failure of any party receiving such notice to reply within the period above fixed shall constitute an election by that party not to participate in the cost of the Completion attempt; provided, that Article VI.B.6. shall control in the case of conflicting Completion proposals. If one or more, but less than all of the parties, elect to attempt a Completion, the provisions of Article VI.B.2. hereof (the phrase "Reworking, Sidetracking, Deepening, Recompleting, or Plugging Back" as contained in Article VI.B.2. shall be deemed to include "Completing") shall apply to the operations thereafter conducted by less than all parties; provided, however, that Article VI.B.2. shall apply separately to each separate Completion or Recompletion attempt undertaken hereunder, and an election to become a Non-Consenting Party as to one Completion or Recompletion attempt shall not prevent a party from becoming a Consenting Party in subsequent Completion or Recompletion attempts regardless whether the Consenting Parties as to earlier Completions or Recompletions have recouped their costs pursuant to Article VI.B.2.; provided further, that any recoupment of costs by a Consenting Party shall be made solely from the production attributable to the Zone in which the Completion attempt is made. Election by a previous Non-Consenting Party to participate in a subsequent Completion or Recompletion attempt shall require such party to pay its proportionate share of the cost of salvable materials and equipment installed in the well pursuant to the previous Completion or Recompletion attempt, insofar and only insofar as such materials and equipment benefit the Zone in which such party participates in a Completion attempt.

2. Rework, Recomplete or Plug Back: No well shall be Reworked, Recompleted or Plugged Back except a well Reworked, Recompleted or Plugged Back pursuant to the provisions of Article VI.B.2. of this agreement. Consent to the Reworking, Recompleting or Plugging Back of a well shall include all necessary expenditures in conducting such operations and Completing and equipping of said well, including necessary tankage and/or surface facilities.

D. Other Operations:

Operator shall not undertake any single project reasonably estimated to require an expenditure in excess of ________________ Dollars ($______) except in connection with the drilling, Sidetracking, Reworking, Deepening, Completing, Recompleting or Plugging Back of a well that has been previously authorized by or pursuant to this agreement; provided, however, that, in case of explosion, fire, flood or other sudden emergency, whether of the same or different nature, Operator may take such steps and incur such expenses as in its opinion are required to deal with the emergency to safeguard life and property but Operator, as promptly as possible, shall report the emergency to the other parties. If Operator prepares an AFE for its own use, Operator shall furnish any Non-Operator so requesting an information copy thereof for any single project costing in excess of _______________ Dollars ($_______). Any party who has not relinquished its interest in a well shall have the right to propose that Operator perform repair work or undertake the installation of artificial lift equipment or ancillary production facilities such as salt water disposal wells or to conduct additional work with respect to a well drilled hereunder or other similarly project (but not including the installation of gathering lines or other transportation or marketing facilities, the installation of which shall be governed by separate agreement between the parties) reasonably estimated to require an expenditure in excess of the amount first set forth above in this Article VI.D. (except in connection with an operation required to be proposed under Articles VI.B.1. or VI.C.1. Option No. 2, which shall be governed exclusively by those Articles). Operator shall deliver such proposal to all parties entitled to participate therein. If, within thirty days thereof, Operator secures the written consent of any party or parties owning at least ___% of the interests of the parties entitled to participate in such operation, each party having the right to participate in such project shall be bound by the terms of such proposal and shall be obligated to pay its proportionate share of the costs of the proposed project as if it had consented to such project pursuant to the terms of the proposal.

E. Abandonment of Wells:

1. Abandonment of Dry Holes: Except for any well drilled or Deepened pursuant to Article VI.B.2., any well which has been drilled or Deepened under the terms of this agreement and is proposed to be completed as a dry hole shall not be plugged and abandoned without the consent of all parties. Should Operator, after diligent effort, be unable to contact any party, or should any party fail to reply within forty-eight (48) hours (exclusive of Saturday, Sunday and legal holidays) after delivery of notice of the proposal to plug and abandon such well, such party shall be deemed to have consented to the proposed abandonment. All such wells shall be plugged and abandoned in accordance with applicable regulations and at the cost, risk and expense of the parties who participated in the cost of drilling or Deepening such well. Any party who objects to plugging and abandoning such well by notice delivered to Operator within forty-eight (48) hours (exclusive of Saturday, Sunday and legal holiday) after delivery of notice of the proposed plugging shall take over the well as of the end of such forty-eight (48) hour notice period and conduct further operations in search of Oil and/or Gas subject to the provisions of Article VI.B.; failure of such party to provide proof reasonably satisfactory to Operator of its financial capability to conduct such operations or to take over the well within such period or thereafter to conduct operations on such well or plug and abandon such well shall entitle Operator to retain or take possession of the well and plug and abandon the well. The party taking over the well shall indemnify Operator (if Operator is an abandoning party) and the other abandoning parties against liability for any further operations conducted on such well except for the costs of plugging and abandoning the well and restoring the surface, for which the abandoning parties shall remain proportionately liable.

2. Abandonment of Wells That Have Produced: Except for any well in which a Non-Consent operation has been conducted hereunder for which the Consenting Parties have not been fully reimbursed as herein provided, any well which has been completed as a producer shall not be plugged and abandoned without the consent of all parties. If all parties consent to such abandonment, the well shall be plugged and abandoned in

accordance with applicable regulations and at the cost, risk and expense of all the parties hereto. Failure of a party to reply within sixty (60) days of delivery of notice of proposed abandonment shall be deemed an election to consent to the proposal. If, within sixty (60) days after delivery of notice of the proposed abandonment of any well, all parties do not agree to the abandonment of such well, those wishing to continue its operation from the Zone then open to production shall be obligated to take over the well as of the expiration of the applicable notice period and shall indemnify Operator (if Operator is an abandoning party) and the other abandoning parties against liability for any further operations on the well conducted by such parties. Failure of such party or parties to provide proof reasonably satisfactory to Operator of their financial capability to conduct such operations or to take over the well within the required period or thereafter to conduct operations on such well shall entitle Operator to retain or take possession of such well and plug and abandon the well.

Parties taking over a well as provided herein shall tender to each of the other parties its proportionate share of the value of the well's salvable material and equipment, determined in accordance with the provisions of Exhibit "C", less the estimated cost of salvaging and the estimated cost of plugging and abandoning and restoring the surface; provided, however, that in the event the estimated plugging and abandoning and surface restoration costs and the estimated cost of salvaging are higher than the value of the well's salvable material and equipment, each of the abandoning parties shall tender to the parties continuing operations their proportionate shares of the estimated excess cost. Each abandoning party shall assign to the non-abandoning parties, without warranty, express or implied, as to title or as to quantity, or fitness for use of the equipment and material, all of its interest in the wellbore of the well and related equipment, together with its interest in the Leasehold insofar and only insofar as such Leasehold covers the right to obtain production from that wellbore in the Zone then open to production. If the interest of the abandoning party is or includes an Oil and Gas Interest, such party shall execute and deliver to the non-abandoning party or parties an oil and gas lease, limited to the wellbore and the Zone then open to production, for a term of one (1) year and so long thereafter as Oil and/or Gas is produced from the Zone covered thereby, such lease to be on the form attached as Exhibit "B". The assignments or leases so limited shall encompass the Drilling Unit upon which the well is located. The payments by, and the assignments or leases to, the assignees shall be in a ratio based upon the relationship of their respective percentage of participation in the Contract Area to the aggregate of the percentages of participation in the Contract Area of all assignees. There shall be no readjustment of interests in the remaining portions of the Contract Area.

Thereafter, abandoning parties shall have no further responsibility, liability, or interest in the operation of or production from the well in the Zone then open other than the royalties retained in any lease made under the terms of this Article. Upon request, Operator shall continue to operate the assigned well for the account of the non-abandoning parties at the rates and charges contemplated by this agreement, plus any additional cost and charges which may arise as the result of the separate ownership of the assigned well. Upon proposed abandonment of the producing Zone assigned or leased, the assignor or lessor shall then have the option to repurchase its prior interest in the well (using the same valuation formula) and participate in further operations therein subject to the provisions hereof.

3. Abandonment of Non-Consent Operations: The provisions of Article VI.E.1. or VI.E.2. above shall be applicable as between Consenting Parties in the event of the proposed abandonment of any well excepted from said Articles; provided, however, no well shall be permanently plugged and abandoned unless and until all parties having the

right to conduct further operations therein have been notified of the proposed abandonment and afforded the opportunity to elect to take over the well in accordance with the provisions of this Article VI.E.; and provided further, that Non-Consenting Parties who own an interest in a portion of the well shall pay their proportionate shares of abandonment and surface restoration costs for such well as provided in Article VI.B.2.(b).

F. Termination of Operations:

Upon the commencement of an operation for the drilling, Reworking, Sidetracking, Plugging Back, Deepening, testing, Completion or plugging of a well, including but not limited to the Initial Well, such operation shall not be terminated without consent of parties bearing ___% of the costs of such operation; provided, however, that in the event granite or other practically impenetrable substance or condition in the hole is encountered which renders further operations impractical, Operator may discontinue operations and give notice of such condition in the manner provided in Article VI.B.1., and the provisions of Article VI.B. or VI.E. shall thereafter apply to such operation, as appropriate.

G. Taking Production in Kind:

☐ **Option No. 1: Gas Balancing Agreement Attached**

Each party shall take in kind or separately dispose of its proportionate share of all Oil and Gas produced from the Contract Area, exclusive of production which may be used in development and producing operations and in preparing and treating Oil and Gas for marketing purposes and production unavoidably lost. Any extra expenditure incurred in the taking in kind or separate disposition by any party of its proportionate share of the production shall be borne by such party. Any party taking its share of production in kind shall be required to pay for only its proportionate share of such part of Operator's surface facilities which it uses.

Each party shall execute such division orders and contracts as may be necessary for the sale of its interest in production from the Contract Area, and, except as provided in Article VII.B., shall be entitled to receive payment directly from the purchaser thereof for its share of all production.

If any party fails to make the arrangements necessary to take in kind or separately dispose of its proportionate share of the Oil produced from the Contract Area, Operator shall have the right, subject to the revocation at will by the party owning it, but not the obligation, to purchase such Oil or sell it to others at any time and from time to time, for the account of the non-taking party. Any such purchase or sale by Operator may be terminated by Operator upon at least ten (10) days written notice to the owner of said production and shall be subject always to the right of the owner of the production upon at least ten (10) days written notice to Operator to exercise at any time its right to take in kind, or separately dispose of, its share of all oil not previously delivered to a purchaser. Any purchase or sale by Operator of any other party's share of Oil shall be only for such reasonable periods of time as are consistent with the minimum needs of the industry under the particular circumstances, but in no event for a period in excess of one (1) year.

Any such sale by Operator shall be in a manner commercially reasonable under the circumstances but Operator shall have no duty to share any existing market or to obtain a price equal to that received under any existing market. The sale or delivery by Operator of a non-taking party's share of Oil under the terms of any existing contact of Operator shall not give the non-taking party any interest in or make the non-taking party a party to said contract. No purchase shall be made by Operator without first giving the non-taking party at least ten (10) days written notice of such intended purchase and the price to be paid or the pricing basis to be used.

All parties shall give timely written notice to Operator of their Gas marketing arrangements for the following month, excluding price, and shall notify Operator immediately in the event of a change in such arrangements. Operator shall maintain records of all marketing arrangements, and of volumes actually sold or transported, which records shall be made available to Non-Operators upon reasonable request.

In the event one or more parties' separate disposition of its share of the gas causes split-steam deliveries to separate pipelines and/or deliveries which on a day-to-day basis for any reason are not exactly equal to a party's respective proportionate share of total gas sales to be allocated to it, the balancing or accounting between the parties shall be in accordance with any gas balancing agreement between the parties hereto, whether such an agreement is attached as Exhibit "E" or is a separate agreement. Operator shall give notice to all parties of the first sales of Gas from any well under this agreement.

☐ **Option No. 2: No Gas Balancing Agreement:**

Each party shall take in kind or separately dispose of its proportionate share of all Oil and Gas produced from the Contract Area, exclusive of production which may be used in development and producing operations and in preparing and treating Oil and Gas for marketing purposes and production unavoidably lost. Any extra expenditure incurred in the taking in kind or separate disposition by any party of its proportionate share of the production shall be borne by such party. Any party taking its share of production in kind shall be required to pay for only its proportionate share of such part of Operator's surface facilities which it uses.

Each party shall execute such division orders and contracts as may be necessary for the sale of its interest in production from the Contract Area, and, except as provided in Article VII.B., shall be entitled to receive payment directly from the purchaser thereof for its share of all production.

If any party fails to make the arrangements necessary to take in kind or separately dispose of its proportionate share of the Oil and/or Gas produced from the Contract Area, Operator shall have the right, subject to the revocation at will be the party owning it, but not the obligation, to purchase such Oil and/or Gas or sell it to others at any time and from time to time, for the account of the non-taking party. Any such purchase or sale by Operator may be terminated by Operator upon at least ten (10) days written notice to the owner of said production and shall be subject always to the right of the owner of the production upon at least ten (10) days written notice to Operator to exercise its right to take in kind, or separately dispose of, its share of all Oil and/or Gas not previously delivered to a purchaser; provided, however, that the effective date of any such revocation may be deferred at the Operator's election for a period not to exceed ninety (90) days if Operator has committed such production to a purchase contract having a term extending beyond such ten (10) day period. Any purchase or sale by Operator of any other party's share of Oil and/or Gas shall be only for such reasonable periods of time as are consistent with the minimum needs of the industry under the particular circumstances, but in no event for a period in excess of one (1) year.

Any such sale by Operator shall be in a manner commercially reasonable under the circumstances, but Operator shall have no duty to share any existing market or transportation arrangement or to obtain a price or transportation fee equal to that received under any existing market or transportation arrangement. The sale or delivery by Operator of a non-taking party's share of production under the terms of any existing contract of Operator shall not give the non-taking party any interest in or make the non-taking party a party to said contract. No purchase of Oil and Gas and no sale of Gas shall be made by Operator without first giving the non-taking party ten days written notice of such intended purchase or sale and the price to be paid or the pricing basis to be used.

Operator shall give notice to all parties of the first sale of Gas from any well under this Agreement.

All parties shall give timely written notice to Operator of their Gas marketing arrangements for the following month, excluding price, and shall notify Operator immediately in the event of a change in such arrangements. Operator shall maintain records of all marketing arrangements, and of volumes actually sold or transported, which records shall be made available to Non-Operators upon reasonable request.

ARTICLE VII.
EXPENDITURES AND LIABILITY OF PARTIES

A. Liability of Parties:

The liability of the parties shall be several, not joint or collective. Each party shall be responsible only for its obligations, and shall be liable only for its proportionate share of the costs of developing and operating the Contact Area. Accordingly, the liens granted among the parties in Article VII.B. are given to secure only the debts of each severally, and no party shall have any liability to third parties hereunder to satisfy the default of any other party in the payment of any expense or obligation hereunder. It is not the intention of the parties to create, nor shall this agreement be construed as creating, a mining or other partnership, joint venture, agency relationship or association, or to render the parties liable as partners, co-venturers, or principals. In their relations with each other under this agreement, the parties shall not be considered fiduciaries or to have established a confidential relationship but rather shall be free to act on an arm's-length basis in accordance with their own respective self-interest, subject, however, to the obligation of the parties to act in good faith in their dealings with each other with respect to activities hereunder.

B. Liens and Security Interests:

Each party grants to the other parties hereto a lien upon any interest it now owns or hereafter acquires in Oil and Gas Leases and Oil and Gas Interests in the Contract Area, and a security interest and/or purchase money security interest in any interest it now owns or hereafter acquires in the personal property and fixtures on or used or obtained for use in connection therewith, to secure performance of all of its obligations under this agreement including but not limited to payment of expense, interest and fees, the proper disbursement of all monies paid hereunder, the assignment or relinquishment of interest in Oil and Gas Leases as required hereunder, and the proper performance of operations hereunder. Such lien and security interest granted by each party hereto shall include such party's leasehold interests, working interests, operating rights, and royalty and overriding royalty interests in the Contract Area now owned or hereafter acquired and in lands pooled or unitized therewith or otherwise becoming subject to this agreement, the Oil and Gas when extracted therefrom and equipment situated thereon or used or obtained for use in connection therewith (including, without limitation, all wells, tools, and tubular goods), and accounts (including, without limitation, accounts arising from the sale of Oil and/or Gas at the wellhead), contract rights, inventory and general intangibles relating thereto or arising therefrom, and all proceeds and products of the foregoing.

To perfect the lien and security agreement provided herein, each party hereto shall execute and acknowledge the recording supplement and/or any financing statement prepared and submitted by any party hereto in conjunction herewith or at any time following execution hereof, and Operator is authorized to file this agreement or the recording supplement executed herewith as a lien or mortgage in the applicable real estate records and as a financing statement with the proper officer under the Uniform Commercial Code in the state in which the Contract Area is situated and such other states as Operator shall deem appropriate to perfect the security interest granted hereunder. Any party may file this agreement, the recording supplement executed herewith, or such other documents as it deems necessary as a lien or mortgage in the applicable real estate records and as a financing statement with the proper officer under the Uniform Commercial Code.

Each party represents and warrants to the other parties hereto that the lien and security interest granted by such party to the other parties shall be a first and prior lien, and each party hereby agrees to maintain the priority of said lien and security interest against all persons acquiring an interest in Oil and Gas Leases and Interests covered by this agreement, by, through and under such party. All parties acquiring an interest in Oil and Gas Leases and Oil and Gas Interests covered by this agreement, whether by assignment, merger, mortgage, operation of law, or otherwise, shall be deemed to have taken subject to the lien and security interest granted by this Article VII.B. as to all obligations attributable to such interest hereunder whether or not such obligations arise before or after such interest is acquired.

To the extent that parties have a security interest under the Uniform Commercial Code of the state in which the Contract Area is situated, they shall be entitled to exercise the rights and remedies of a secured party under the Code. The bringing of a suit and the obtaining of judgment by a party for the secured indebtedness shall not be deemed an election of remedies or otherwise affect the lien rights or security interest as security for the payment thereof. In addition, upon default by any party in the payment of its share of expenses, interests or fees, or upon the improper use of funds by the Operator, the other parties shall have the right, without prejudice to other rights or remedies, to collect from the purchaser the proceeds from the sale of such defaulting party's share of Oil and Gas until the amount owed by such party, plus interest as provided in Exhibit "C," has been received, and shall have the right to offset the amount owed against the proceeds from the sale of such defaulting party's share of Oil and Gas. All purchasers of production may rely on a notification of default from the non-defaulting party or parties stating the amount due as a result of the default, and all parties waive any recourse available against purchasers for releasing production proceeds as provided in this paragraph.

If any party fails to pay its share of cost within one hundred twenty (120) days after rendition of a statement therefor by Operator, the non-defaulting parties, including Operator, shall, upon request by Operator, pay the unpaid amount in the proportion that the interest of each such party bears to the interest of all such parties. The amount paid by each party so paying its share of the unpaid amount shall be secured by the liens and security rights described in Article VII.B., and each paying party may independently pursue any remedy available hereunder or otherwise.

If any party does not perform all of its obligations hereunder, and the failure to perform subjects such party to foreclosure or execution proceedings pursuant to the provisions of this agreement, to the extent allowed by governing law, the defaulting party waives any available right of redemption from and after the date of judgment, any required valuation or appraisement of the mortgaged or secured property prior to sale, any available right to stay execution or to require a marshalling of assets and any required bond in the event a receiver is appointed. In addition, to the extent permitted by applicable law, each party hereby grants to the other parties a power of sale as to any property that is subject to the lien and security rights granted hereunder, such power to be exercised in the manner provided by applicable law or otherwise in a commercially reasonable manner and upon reasonable notice.

Each party agrees that the other parties shall be entitled to utilize the provision of Oil and Gas lien law or other lien law of any state in which the Contract Area is situated to enforce the obligations of each party hereunder. Without limiting the generality of the foregoing, to the extent permitted by applicable law, Non-Operators agree that Operator may invoke or utilize the mechanics' or materialmen's lien law of the state in which the Contract Area is situated in order to secure the payment to Operator of any sum due hereunder for services performed or materials supplied by Operator.

C. Advances:

Operator, at its election, shall have the right from time to time to demand and receive from one or more of the other parties payment in advance of their respective shares of the estimated amount of the expense to be incurred in operations hereunder during the next succeeding month, which right may be exercised only by submission to each such party of an itemized statement of such estimated expense, together with an invoice for its share thereof. Each such statement and invoice for the payment in advance of estimated expense shall be submitted on or before the 20th day of the next preceding month. Each party shall pay to Operator its proportionate share of such estimate within fifteen (15) days after such estimate and invoice is received. If any party fails to pay its share of said estimate within said time, the amount due shall bear interest as provided in Exhibit "C" until paid. Proper adjustment shall be made monthly between advances and actual expense to the end that each party shall bear and pay its proportionate share of actual expenses incurred, and no more.

D. Defaults and Remedies:

If any party fails to discharge any financial obligation under this agreement, including without limitation the failure to make any advance under the preceding Article VII.C. or any other provision of this agreement, within the period required for such payment hereunder, then in addition to the remedies provided in Article VII.B. or elsewhere in this agreement, the following remedies shall be applicable. For purposes of this Article VII.D., all notices and elections shall be delivered only by the Operator, except that Operator shall deliver any such notice and election requested by a non-defaulting Non-Operator, and when the Operator is the party in default, the applicable notices and elections can be delivered by any Non-Operator. Election of any one or more of the following remedies shall not preclude the subsequent use of any other remedy specified below or otherwise available to a non-defaulting party.

1. Suspension of Rights: Any party may deliver to the party in default a Notice of Default, which shall specify the default, specify the action to be taken to cure the default, and specify that failure to take such action will result in the exercise of one or more of the remedies provided in this Article. If the default is not cured within thirty (30) days of the delivery of such Notice of Default, all of the rights of the defaulting party granted by this agreement shall be suspended until the default is cured, without prejudice to the right of the non-defaulting party or parties to continue to enforce the obligations of the defaulting party previously accrued or thereafter accruing under this agreement. If Operator is the party in default, the Non-Operators shall have in addition the right, by vote of Non-Operators owning a majority in interest in the Contract Area after excluding the voting interest of Operator, to appoint a new Operator effective immediately. The rights of a defaulting party that may be suspended hereunder at the election of the non-defaulting parties shall include, without limitation, the right to receive information as to any operation conducted hereunder during the period of such default, the right to elect to participate in an operation proposed under Article VI.B. of this agreement, the right to participate in an operation being conducted under this agreement even if the party has previously elected to participate in such operation, and the right to receive proceeds of

production from any well subject to this Agreement.

2. Suit for Damages: Non-defaulting parties or Operator for the benefit of non-defaulting parties may sue (at joint account expense) to collect the amounts in default, plus interest accruing on the amounts recovered from the date of default until the date of collection at the rate specified in Exhibit "C" attached hereto. Nothing herein shall prevent any party from suing any defaulting party to collect consequential damages accruing to such party as a result of the default.

3. Deemed Non-Consent: The non-defaulting party may deliver a written Notice of Non-Consent Election to the defaulting party at any time after the expiration of the thirty-day cure period following delivery of the Notice of Default, in which event if the billing is for the drilling of a new well or the Plugging Back, Sidetracking, Reworking or Deepening of a well which is to be or has been plugged as a dry hole, or for the Completion of any well, the defaulting party will be conclusively deemed to have elected not to participate in the operation and to be a Non-Consenting Party with respect thereto under Article VI.B. or VI.C., as the case may be, to the extent of the costs unpaid by such party, notwithstanding any election to participate theretofore made. If election is made to proceed under this provision, then the non-defaulting parties may not elect to sue for the unpaid amount pursuant to Article VII.D.2

Until the delivery of such Notice of Nonconsent Election to the defaulting party, such party shall have the right to cure its default by paying its unpaid share of costs plus interest at the rate set forth in Exhibit "C", provided, however, such payment shall not prejudice the rights of the non-defaulting parties to pursue remedies for damages incurred by the non-defaulting parties as a result of the default. Any interest relinquished pursuant to this Article VII.D.3. shall be offered to the non-defaulting parties in proportion to their interests, and the non-defaulting parties electing to participate in the ownership of such interest shall be required to contribute their shares of the defaulted amount upon their election to participate therein.

4. Advance Payment: If a default is not cured within thirty (30) days of the delivery of a Notice of Default, Operator, or the Non-Operators if the Operator is the defaulting party, may thereafter require advance payment from the defaulting party of such defaulting party's anticipated share of any item of expense for which the Operator, or Non-Operators, as the case may be, would be entitled to reimbursement under any provision of this agreement, whether or not such expense was the subject of the previous default. Such right includes, but is not limited to, the right to require advance payment for the estimated costs of drilling a well or Completion of a well as to which an election to participate in drilling or Completion has been made. If the defaulting party fails to pay the required advance payment, the non-defaulting parties may pursue any of the remedies provided in this Article VII.D. or any other default remedy provided elsewhere in this agreement. Any excess of funds advanced remaining when the operation is completed and all costs have been paid shall be promptly returned to the advancing party.

5. Costs and Attorneys' Fees: In the event any party is required to bring legal proceedings to enforce any financial obligation of a party hereunder, the prevailing party in such action shall be entitled to recover all court costs, costs of collection and a reasonable attorney's fee, which the lien provided for herein shall also secure.

E. Rentals, Shut-in Well Payments and Minimum Royalties:

Rentals, shut-in well payments and minimum royalties which may be required under the terms of any lease shall be paid by the party or parties who subjected such lease to this agreement at its or their expense. In the event two or more parties own and have contributed interests in the same lease to this agreement, such parties may designate one of such parties to make said payments for and on behalf of all such parties. Any party may request, and shall be entitled to receive, proper evidence of all such payments. In the event of failure to make proper payment of any rental, shut-in well payment or minimum royalty through mistake or oversight where such payment is required to continue the lease in force, any loss which results from such non-payment shall be borne in accordance with the provisions of Article IV.B.2.

Operator shall notify Non-Operators of the anticipated completion of a shut-in well, or the shutting in or return to production of a producing well, at least five (5) days (excluding Saturday, Sunday and legal holidays) prior to taking such action, or at the earliest opportunity permitted by circumstances, but assumes no liability for failure to do so. In the event of failure by Operator to so notify Non-Operators, the loss of any lease contributed hereto by Non-Operators for failure to make timely payments of any shut-in well payment shall be borne jointly by the parties hereto under the provisions of Article IV.B.3.

F. Taxes:

Beginning with the first calendar year after the effective date hereof, Operator shall render for ad valorem taxation all property subject to this agreement which by law should be rendered for such taxes, and it shall pay all such taxes assessed thereon before they become delinquent. Prior to the rendition date, each Non-Operator shall furnish Operator information as to burdens (to include, but not be limited to, royalties, overriding royalties and production payments) on Leases and Oil and Gas Interests contributed by such Non-Operator. If the assessed valuation of any Lease is reduced by reason of its being subject to outstanding excess royalties, overriding royalties or production payments, the reduction in ad valorem taxes resulting therefrom shall inure to the benefit of the owner or owners of such Lease, and Operator shall adjust the charge to such owner or owners so as to reflect the benefit of such reduction. If the ad valorem taxes are based in whole or in part upon separate valuations of each party's working interest, then notwithstanding anything to the contrary herein, charges to the joint account shall be made and paid by the parties hereto in accordance with the tax value generated by each party's working interest. Operator shall bill the other parties for their proportionate shares of all tax payments in the manner provided in Exhibit "C".

If Operator considers any tax assessment improper, Operator may, at its discretion, protest within the time and manner prescribed by law, and prosecute the protest to a final determination, unless all parties agree to abandon the protest prior to final determination. During the pendency of administrative or judicial proceedings, Operator may elect to pay, under protest, all such taxes and any interest and penalty. When any such protested assessment shall have been finally determined, Operator shall pay the tax for the joint account, together with any interest and penalty accrued, and the total cost shall then be assessed against the parties, and be paid by them, as provided in Exhibit "C".

Each party shall pay or cause to be paid all production, severance, excise, gathering and other taxes imposed upon or with respect to the production or handling of such party's share of Oil and Gas produced under the terms of this agreement.

ARTICLE VIII.
ACQUISITION, MAINTENANCE OR TRANSFER OF INTEREST

A. Surrender of Leases:

The Leases covered by this agreement, insofar as they embrace acreage in the Contract Area, shall not be surrendered in whole or in part unless all parties consent thereto.

However, should any party desire to surrender its interest in any Lease or in any portion thereof, such party shall give written notice of the proposed surrender to all parties, and the parties to whom such notice is delivered shall have thirty (30) days after delivery of the notice within which to notify the party proposing the surrender whether they elect to consent thereto. Failure of a party to whom such notice is delivered to reply within said 30-day period shall constitute a consent to the surrender of the Leases described in the notice. If all parties do not agree or consent thereto, the party desiring to surrender shall assign, without express or implied warranty of title, all of its interest in such Lease, or portion thereof, and any well, material and equipment which may be located thereon and any rights in production thereafter secured, to the parties not consenting to such surrender. If the interest of the assigning party is or includes an Oil and Gas Interest, the assigning party shall execute and deliver to the party or parties not consenting to such surrender an oil and gas lease covering such Oil and Gas Interest for a term of one (1) year and so long thereafter as Oil and/or Gas is produced from the land covered thereby, such lease to be on the form attached hereto as Exhibit "B". Upon such assignment or lease, the assigning party shall be relieved from all obligations thereafter accruing, but not theretofore accrued, with respect to the interest assigned or leased and the operation of any well attributable thereto, and the assigning party shall have no further interest in the assigned or leased premises and its equipment and production other than the royalties retained in any lease made under the terms of this Article. The party assignee or lessee shall pay to the party assignor or lessor the reasonable salvage value of the latter's interest in any well's salvable materials and equipment attributable to the assigned or leased acreage. The value of all salvable materials and equipment shall be determined in accordance with the provisions of Exhibit "C", less the estimated cost of salvaging and the estimated cost of plugging and abandoning and restoring the surface. If such value is less than such costs, then the party assignor or lessor shall pay to the party assignee or lessee the amount of such deficit. If the assignment or lease is in favor of more than one party, the interest shall be shared by such parties in the proportions that the interest of each bears to the total interest of all such parties. If the interest of the parties to whom the assignment is to be made varies according to depth, then the interest assigned shall similarly reflect such variances.

Any assignment, lease or surrender made under this provision shall not reduce or change the assignor's, lessor's or surrendering party's interest as it was immediately before the assignment, lease or surrender in the balance of the Contract Area; and the acreage assigned, leased or surrendered, and subsequent operations thereon, shall not thereafter be subject to the terms and provisions of this agreement but shall be deemed subject to an Operating Agreement in the form of this agreement.

B. Renewal or Extension of Leases:

If any party secures a renewal or replacement of an Oil and Gas Lease or Interest subject to this agreement, then all other parties shall be notified promptly upon such acquisition or, in the case of a replacement Lease taken before expiration of an existing Lease, promptly upon expiration of the existing Lease. The parties notified shall have the right for a period of thirty (30) days following delivery of such notice in which to elect to participate in the ownership of the renewal or replacement Lease, insofar as such Lease affects lands within the Contract Area, by paying to the party who acquired it their several proper proportionate shares of the acquisition cost allocated to that part of such Lease within the Contract Area, which shall be in proportion to the interests held at that time by the parties in the Contract Area. Each party who participates in the purchase of a renewal or replacement Lease shall be given an assignment of its proportionate interest therein by the acquiring party.

If some, but less than all, of the parties elect to participate in the purchase of a renewal or replacement Lease, it shall be owned by the parties who elect to participate therein, in a ratio based upon the relationship of their respective percentage of participation in the Contract Area to the aggregate of the percentages of participation in the Contract Area of all parties participating in the purchase of such renewal or replacement Lease. The acquisition of a renewal or replacement Lease by any or all of the parties hereto shall not cause a readjustment of the interests of the parties stated in Exhibit "A", but any renewal or replacement Lease in which less than all parties elect to participate shall not be subject to this agreement but shall be deemed subject to a separate Operating Agreement in the form of this agreement.

If the interests of the parties in the Contract Area vary according to depth, then their right to participate proportionately in renewal or replacement Leases and their right to receive an assignment of interest shall also reflect such depth variances.

The provisions of this Article shall apply to renewal or replacement Leases whether they are for the entire interest covered by the expiring Lease or cover only a portion of its area or an interest therein. Any renewal or replacement Lease taken before the expiration of its predecessor Lease, or taken or contracted for or becoming effective within six (6) months after the expiration of the existing Lease, shall be subject to this provision so long as this agreement is in effect at the time of such acquisition or at the time the renewal or replacement Lease become effective; but any Lease taken or contracted for more than six (6) months after the expiration of an existing Lease shall not be deemed a renewal or replacement Lease and shall not be subject to the provisions of this agreement.

The provisions in this Article shall also be applicable to extensions of Oil and Gas Leases.

C. Acreage or Cash Contributions:

While this agreement is in force, if any party contracts for a contribution of cash towards the drilling of a well or any other operation on the Contract Area, such contribution shall be paid to the party who conducted the drilling or other operation and shall be applied by it against the cost of such drilling or other operation. If the contribution be in the form of acreage, the party to whom the contribution is made shall promptly tender an assignment of the acreage, without warranty of title, to the Drilling Parties in the proportions said Drilling Parties shared the cost of drilling the well. Such acreage shall become a separate Contract Area and, to the extent possible, be governed by provisions identical to this agreement. Each party shall promptly notify all other parties of any acreage or cash contributions it may obtain in support of any well or any other operation on the Contract Area. The above provisions shall also be applicable to optional rights to earn acreage outside the Contract Area which are in support of a well drilled inside the Contract Area.

If any party contracts for any consideration relating to disposition of such party's share of substances produced hereunder, such consideration shall not be deemed a contribution as contemplated in this Article VIII.C.

D. Assignment; Maintenance of Uniform Interest:

For the purpose of maintaining uniformity of ownership in the Contract Area in the Oil and Gas Lease, Oil and Gas Interests, wells, equipment and production covered by this agreement no party shall sell, encumber, transfer or make other disposition of its interest in the Oil and Gas Leases and Oil and Gas Interests embraced within the Contract Area or in wells, equipment and production unless such disposition covers either:

1. the entire interest of the party in all Oil and Gas Leases, Oil and Gas Interests, wells, equipment and production; or
2. an equal undivided percent of the party's present interest in all Oil and Gas Leases, Oil and Gas Interests, wells, equipment and production in the Contract Area.

Every sale, encumbrance, transfer or other disposition made by any party shall be made expressly subject to this agreement and shall be made without prejudice to the right of the other parties, and any transferee of any ownership interest in any Oil and Gas Lease or Interest shall be deemed a party to this agreement as to the interest conveyed from and after the effective date of the transfer of ownership; provided, however, that the other parties shall not be required to recognize any such sale, encumbrance, transfer or other disposition for any purpose hereunder until thirty (30) days after they have received a copy of the instrument of transfer or other satisfactory evidence thereof in writing from the transferor or transferee. No assignment or other disposition of interest by a party shall relieve such party of obligations previously incurred by such party hereunder with respect to the interest transferred, including without limitation the obligation of a party to pay all costs attributable to an operation conducted hereunder in which such party has agreed to participate prior to making such assignment, and the lien and security interest granted by Article VII.B. shall continue to burden the interest transferred to secure payment of any such obligations.

If, at any time the interest of any party is divided among and owned by four or more co-owners, Operator, at its discretion, may require such co-owners to appoint a single trustee or agent with full authority to receive notices, approve expenditures, receive billings for and approve and pay such party's share of the joint expenses, and to deal generally with, and with power to bind, the co-owners of such party's interest within the scope of the operations embraced in this agreement; however, all such co-owners shall have the right to enter into and execute all contracts or agreements for the disposition of their respective shares of the Oil and Gas produced from the Contract Area and they shall have the right to receive, separately, payment of the sale proceeds thereof.

E. Waiver of Rights to Partition:

If permitted by the laws of the state or states in which the property covered hereby is located, each party hereto owning an undivided interest in the Contract Area waives any and all rights it may have to partition and have set aside to it in severalty its undivided interest therein.

F. Preferential Right to Purchase:

☐ (Optional; Check if applicable.)

Should any party desire to sell all or any part of its interests under this agreement, or its rights and interests in the Contract Area, it shall promptly give written notice to the other parties, with full information concerning its proposed disposition, which shall include the name and address of the prospective transferee (who must be ready, willing and able to purchase), the purchase price, and all other terms of the offer. The other parties shall then have an optional prior right, for a period of ten (10) days after the notice is delivered, to purchase for the stated consideration on the same terms and conditions the interest which the other party proposes to sell; and, if this optional right is exercised, the purchasing parties shall share the purchased interest in the proportions that the interest of each bears to the total interest of all purchasing parties. However, there shall be no preferential right to purchase in those cases where any party wishes to mortgage its interests, or to transfer title to its interests to its mortgagee in lieu of or pursuant to foreclosure of a mortgage of its interests, or to dispose of its interests by merger, reorganization, consolidation, or by sale of all or substantially all of its Oil and Gas assets to any party, or by transfer of its interests to a subsidiary or parent company or to a subsidiary of a parent company, or to any company in which such party owns a majority of the stock.

ARTICLE IX.
INTERNAL REVENUE CODE ELECTION

If, for federal income tax purposes, this agreement and the operations hereunder are regarded as a partnership, and if the parties have not otherwise agreed to form a tax partnership pursuant to Exhibit "G" or other agreement between them, each party thereby affected elects to be excluded from the application of all of the provisions of Subchapter "K", Chapter 1, Subtitle "A", of the Internal Revenue Code of 1986, as amended ("Code"), as permitted and authorized by Section 761 of the Code and the regulations promulgated thereunder. Operator is authorized and directed to execute on behalf of each party hereby affected such evidence of this election as may be required by the Secretary of the Treasury of the United States or the Federal Internal Revenue Service, including specifically, but not by way of limitation, all of the returns, statements, and the data required by Treasury Regulations e 1.761. Should there by any requirement that each party hereby affected give further evidence of this election, each such party shall execute such documents and furnish such other evidence as may be required by the Federal Internal Revenue Service or as may be necessary to evidence this election. No such party shall give any notices or take any other action inconsistent with the election made hereby. If any present or future income tax laws of the state or states in which the Contract Area is located or any future income tax laws of the United States contain provisions similar to those in Subchapter "K", Chapter 1, Subtitle "A", of the Code under which an election similar to that provided by Section 761 of the Code is permitted, each party hereby affected shall make such election as may be permitted or required by such laws. In making the foregoing election, each such party states that the income derived by such party from operations hereunder can be adequately determined without the computation of partnership taxable income.

ARTICLE X.
CLAIMS AND LAWSUITS

Operator may settle any single uninsured third party damage claim or suit arising from operations hereunder if the expenditure does not exceed _________________Dollars ($__________) and if the payment is in complete settlement of such claim or suit. If the amount required for settlement exceeds the above amount, the parties hereto shall assume and take over the further handling of the claim or suit, unless such authority is delegated to Operator. All costs and expenses of handling, settling, or otherwise discharging such claim or suit shall be at the joint expense of the parties participating in the operation from which the claim or suit arises. If a claim is made against any party or if any party is sued on account of any matter arising from operations hereunder over which such individual has no control because of the rights given Operator by this agreement, such party shall immediately notify all other parties, and the claim or suit shall be treated as any other claim or suit involving operations hereunder.

ARTICLE XI.
FORCE MAJEURE

If any party is rendered unable, wholly or in part, by force majeure to carry out its obligations under this agreement, other than the obligation to indemnify or make money payments or furnish security, that party shall give to all other parties prompt written notice of the force majeure with reasonably full particulars concerning it; thereupon, the obligations of the party giving the notice, so far as they are affected by the force majeure, shall be suspended during, but no longer than, the continuance of the force majeure. The term "force majeure", as here employed, shall mean an act of God, strike, lockout, or other industrial disturbance, act of the public enemy, war, blockade, public riot, lightning, fire, storm, flood or other act of nature, explosion, governmental action, governmental delay, restraint or inaction, unavailability of equipment, and any other cause, whether of the kind specifically enumerated above or otherwise, which is not reasonably within the control of the party claiming suspension.

The affected party shall use all reasonable diligence to remove the force majeure situation as quickly as practicable. The requirement that any force majeure shall be remedied with all reasonable dispatch shall not require the settlement of strikes, lockouts, or other labor difficulty by the party involved, contrary to its wishes; how all such difficulties shall be handled shall be entirely within the discretion of the party concerned.

ARTICLE XII.
NOTICES

All notices authorized or required between the parties by any of the provisions of this agreement, unless otherwise specifically provided, shall be in writing and delivered in person or by United States mail, courier service, telegram, telex, telecopier or any other form of facsimile, postage or charges prepaid, and addressed to such parties at the addresses listed on Exhibit "A". All telephone or oral notices permitted by this agreement shall be confirmed immediately thereafter by written notice. The originating notice given under any provision hereof shall be deemed delivered only when received by the party to whom such notice is directed, and the time for such party to deliver any notice in response thereto shall run from the date the originating notice is received. "Receipt" for purposes of this agreement with respect to written notice delivered hereunder shall be actual delivery of the notice to the address of the party to be notified specified in accordance with this agreement, or to the telecopy, facsimile or telex machine of such party. The second or any responsive notice shall be deemed delivered when deposited in the United States mail or at the office of the courier or telegraph service, or upon transmittal by telex, telecopy or facsimile, or when personally delivered to the party to be notified, provided, that when response is required within 24 or 48 hours, such response shall be given orally or by telephone, telex, telecopy or other facsimile within such period. Each party shall have the right to change its address at any time, and from time to time, by giving written notice thereof to all other parties. If a party is not available to receive notice orally or by telephone when a party attempts to deliver a notice required to be delivered within 24 or 48 hours, the notice may be delivered in writing by any other method specified herein and shall be deemed delivered in the same manner provided above for any responsive notice.

ARTICLE XIII.
TERM OF AGREEMENT

This agreement shall remain in full force and effect as to the Oil and Gas Leases and/or Oil and Gas Interests subject hereto for the period of time selected below; provided, however, no party hereto shall ever be construed as having any right, title or interest in or to any Lease or Oil and Gas Interest contributed by any other party beyond the term of this agreement.

☐ Option No. 1: So long as any of the Oil and Gas Leases subject to this agreement remain or are continued in force as to any part of the Contract Area, whether by production, extension, renewal or otherwise.

☐ Option No. 2: In the event the well described in Article VI.A., or any subsequent well drilled under any provision of this agreement, results in the Completion of a well as a well capable of production of Oil and/or Gas in paying quantities, this agreement shall continue in force so long as any such well is capable of production, and for an additional period of ______ days thereafter; provided, however, if, prior to the expiration of such additional period, one or more of the parties hereto are engaged in drilling, Reworking, Deepening, Sidetracking, Plugging Back, testing or attempting to Complete or Recomplete a well or wells hereunder, this agreement shall continue in force until such operations have been completed and if production results therefrom, this agreement shall continue in force as provided herein. In the event the well described in Article VI.A., or any subsequent well drilled hereunder, results in a dry hole, and no other well is capable of producing Oil and/or Gas from the Contract Area this agreement shall terminate unless drilling, Deepening, Sidetracking, Completing, Recompleting, Plugging Back or Reworking operations are commenced within ________ days from the date of abandonment of said well. "Abandonment" for such purposes shall mean either (i) a decision by all parties not to conduct any further operations on the well or (ii) the elapse of 180 days from the conduct of any operations on the well, whichever first occurs.

The termination of this agreement shall not relieve any party hereto from any expense, liability or other obligation or any remedy therefore which has accrued or attached prior to the date of such termination.

Upon termination of this agreement and the satisfaction of all obligations hereunder, in the event a memorandum of this Operating Agreement has been filed of record, Operator is authorized to file of record in all necessary recording offices a notice of termination as to each Operator's interest upon request of Operator, if Operator has satisfied all its financial obligations.

ARTICLE XIV.
COMPLIANCE WITH LAWS AND REGULATIONS

A. Laws, Regulations and Orders:

This agreement shall be subject to the applicable laws of the state in which the Contract Area is located, to the valid rules, regulations, and orders of any duly constituted regulatory body of said state; and to all other applicable federal, state, and local laws, ordinances, rules, regulations and orders.

B. Governing Law:

This agreement and all matters pertaining hereto, including but not limited to matters of performance, non-performance, breach, remedies, procedures, rights, duties, and interpretation or construction, shall be governed and determined by the law of the state in which the Contract Area is located. If the Contract Area is in two or more states, the law of the state of ____________ shall govern.

C. Regulatory Agencies:

Nothing herein contained shall grant, or be construed to grant, Operator the right or authority to waive or release any rights, privileges, or obligations which Non-Operators may have under federal or state laws or under rules, regulations or orders promulgated under such laws in reference to oil, gas and mineral operations, including the location, operation, or production of wells, on tracts offsetting or adjacent to the Contract Area.

With respect to the operations hereunder, Operators agree to release Operator from any and all losses, damages, injuries, claims and causes of action arising out of, incident to or resulting directly or indirectly from Operator's interpretation or application of rules, rulings, regulations or orders of the Department of Energy or Federal Energy Regulatory Commission or predecessor or successor agencies to the extent such interpretation or application was made in good faith and does not constitute gross negligence. Each Non-Operator further agrees to reimburse Operator for such non-Operator's share of production or any refund, fine, levy or other governmental sanction that Operator may be required to pay as a result of such an incorrect interpretation or application, together with interest and penalties thereon owing by Operator as a result of such incorrect interpretation or application.

ARTICLE XV.
MISCELLANEOUS

A. Execution:

This agreement shall be binding upon each Non-Operator when this agreement or a counterpart thereof has been executed by such Non-Operator and Operator notwithstanding that this agreement is not then or thereafter executed by all of the parties to which it is tendered or which are listed on Exhibit "A" as owning an interest in the Contract Area or which own, in fact, an interest in the Contract Area. Operator may, however, by written notice to all Non-Operators who have become bound by this agreement as aforesaid, given at any time prior to the actual spud date of the Initial Well but in no event later than five days prior to the date specified in Article VI.A. for commencement of the Initial Well, terminate this agreement if Operator in its sole discretion determines that there is insufficient participation to justify commencement of drilling operations. In the event of such a termination by Operator, all further obligations of the parties hereunder shall cease as of such termination. In the event any Non-Operator has advanced or prepaid any share of drilling or other costs hereunder, all sums so advanced shall be returned to such Non-Operator without interest. In the event Operator proceeds with drilling operations for the Initial Well without the execution hereof by all persons listed on Exhibit "A" as having a current working interest in such well, Operator shall indemnify Non-Operators with respect to all costs incurred for the Initial Well which would have been charged to such person under this agreement if such person had executed the same and Operator shall receive all revenues which would have been received by such person under this agreement if such person had executed the same.

B. Successors and Assigns:

This agreement shall be binding upon and shall inure to the benefit of the parties hereto and to their respective heirs, devisees, legal representatives, successors and assigns, and the terms hereof shall be deemed to run with the Leases or Interests included within the Contract Area.

C. Counterparts:

This instrument may be executed in any number of counterparts, each of which shall be considered an original for all purposes.

D. Severability:

For the purposes of assuming or rejecting this agreement as an executory contract pursuant to federal bankruptcy laws, this agreement shall not be severable, but rather must be assumed or rejected in its entirety, and the failure of any party to this agreement to comply with all of its financial obligations provided herein shall be material default.

ARTICLE XVI.
OTHER PROVISIONS

IN WITNESS WHEREOF, this agreement shall be effective as of the _____ day of________, 19__.

ATTEST OR WITNESS: OPERATOR

______________________________ By ______________________________

______________________________ ______________________________
Type or print name

Title______________________________

Date______________________________

Tax ID or S.S. No.______________________

NON-OPERATORS

______________________________ By ______________________________
______________________________ ______________________________
Type or print name

Title______________________________

Date______________________________

Tax ID or S.S. No.______________________

______________________________ By ______________________________
______________________________ ______________________________
Type or print name

Title______________________________

Date______________________________

Tax ID or S.S. No.______________________

______________________________ By ______________________________
______________________________ ______________________________
Type or print name

Title______________________________

Date______________________________

Tax ID or S.S. No.______________________

ACKNOWLEDGMENTS

Note: The following forms of acknowledgment are the short forms approved by the Uniform Law on Notarial Acts. The validity and effect of these forms in any state will depend upon the statutes of that state.

Individual acknowledgment:

State of__________________________§
§ ss.

County of ______________________ §

This instrument was acknowledged before me on __________________________ by ___________________.

(Seal, if any) __________________________

Title (and Rank) _____________

My Commission expires: ______

Acknowledgment in representative capacity:

State of_________________________ §
§ ss.
County of ______________________ §

This instrument was acknowledged before me on _________________________ by _____________________ as ________________ of ______________________.

(Seal, if any) __________________________

Title (and Rank) _____________

My Commission expires: ______

MODEL FORM RECORDING SUPPLEMENT TO
OPERATING AGREEMENT AND FINANCING STATEMENT
(AAPL Form 610RS - 1989)

THIS AGREEMENT, entered into by and between__________________________ hereinafter referred to as "Operator", and the signatory party or parties other than Operator, hereinafter referred to individually as "Non-Operator", and collectively as "Non-Operators".

WHEREAS, the parties to this agreement are owners of Oil and Gas Leases and/or Oil and Gas Interests in the land identified in Exhibit "A" (said land, Leases and Interests being hereinafter called the "Contract Area"), and in any instance in which the Leases or Interests of a party are not of record, the record owner and the party hereto that owns the interest or rights therein are reflected on Exhibit "A";

WHEREAS, the parties hereto have executed an Operating Agreement dated_________(herein the "Operating Agreement"), covering the Contract Area for the purpose of exploring and developing such lands, Leases and Interests for Oil and Gas; and

WHEREAS, the parties hereto have executed this agreement for the purpose of imparting notice to all persons of the rights and obligations of the parties under the Operating Agreement and for the further purpose of perfecting those rights capable of perfection.

NOW, THEREFORE, in consideration of the mutual rights and obligations of the parties hereto, it is agreed as follows:

1. This agreement supplements the Operating Agreement, which Agreement in its entirety is incorporated herein by reference, and all terms used herein shall have the meaning ascribed to them in the Operating Agreement.

2. The parties do hereby agree that:

A. The Oil and Gas Leases and /or Oil and Gas Interests of the parties comprising the Contract Area shall be subject to and burdened with the terms and provisions of this agreement and the Operating Agreement, and the parties do hereby commit such Leases and Interests to the performance thereof.

B. The exploration and development of the Contract Area for Oil and Gas shall be governed by the terms and provisions of the Operating Agreement, as supplemented by this agreement.

C. All costs and liabilities incurred in operations under this agreement and the Operating Agreement shall be borne and paid, and all equipment and materials required in operations on the Contract Area shall be owned, by the parties hereto, as provided in the Operating Agreement.

D. Regardless of the record title ownership to the Oil and Gas Leases and/or Oil and Gas Interests identified on Exhibit "A", all production of Oil and Gas from the Contract Area shall be owned by the parties as provided in the Operating Agreement; provided nothing contained in this agreement shall be deemed an assignment or cross-assignment of interests covered hereby.

E. Each party shall pay or deliver, or cause to be paid or delivered all burdens on its share of the production from the Contract Area as provided in the Operating Agreement.

F. An overriding royalty, production payment net profits interest or other burden payable out of production hereafter created, assignments of production given as security for the payment of money and those overriding royalties, production payments and other burdens payable out of production heretofore created and defined as Subsequently Created Interests in the Operating Agreement shall be (i) borne solely by the party whose interest is burdened therewith, (ii) subject to suspension if a party is required to assign or relinquish to another party an interest which is subject to such burden, and (iii) subject to the lien and security interest hereinafter provided if the party subject to such burden fails to pay its share of expenses chargeable hereunder and under the Operating Agreement, all upon the terms and provisions and in the times and manner provided by the Operating Agreement.

G. The Oil and Gas Leases and/or Oil and Gas Interests which are subject hereto may not be assigned or transferred except in accordance with those terms, provisions and restrictions in the Operating Agreement regulating such transfers. This agreement and the Operating Agreement shall be binding upon and shall inure to the benefit of the parties hereto, and their respective heirs, devisees, legal representatives, and assigns, and the terms hereof shall be deemed to run with the leases or interests included within the lease Contract Area.

H. The parties shall have the right to acquire and interest in renewal, extension and replacement leases, leases proposed to be surrendered, wells proposed to be abandoned, and interests to be relinquished as a result of non-participation in subsequent operations, all in accordance with the terms and provisions of the Operating Agreement.

I. The rights and obligations of the parties and the adjustment of interests among them in the event of a failure or loss of title, each party's right to propose operations, obligations with respect to participation in operations on the Contract Area and the consequences of a failure to participate in operations, the rights and obligations of the parties regarding the marketing of production, and the rights and remedies of the parties for failure to comply with financial obligations shall be as provided in the Operating Agreement.

J. Each party's interest under this agreement and under the Operating Agreement shall be subject to relinquishment for its failure to participate in subsequent operations and each party's share of production and costs shall be reallocated on the basis of such relinquishment, all upon the terms and provisions provided in the Operating Agreement.

K. All other matters with respect to exploration and development of the Contract Area and the ownership and transfer of the Oil and Gas Leases and/or Oil and Gas Interest therein shall be governed by the terms and provisions of the Operating Agreement.

3. The parties hereby grant reciprocal liens and security interests as follows:

A. Each party grants to the other parties hereto a lien upon any interest it now owns or hereafter acquires in Oil and Gas Leases and Oil and Gas Interests in the Contract Area, and a security interest and/or purchase money security interest in any interest it now owns or hereafter acquires in the personal property and fixtures on or used or obtained for use in connection therewith, to secure performance of all of its obligations under this agreement and the Operating Agreement including but not limited to payment of expense, interest and fees, the proper disbursement of all monies paid under this agreement and the Operating Agreement, the assignment or relinquishment of interest in Oil and Gas Leases as required under this agreement and the Operating Agreement, and the proper performance of operations under this agreement and the Operating Agreement. Such lien and security interest granted by each party hereto shall include such party's leasehold interests, working interests, operating rights, and royalty and overriding royalty interests in the Contract Area now owned or hereafter acquired and in lands pooled or unitized therewith or otherwise becoming subject to this agreement and the Operating Agreement, the Oil and Gas when extracted therefrom and equipment situated thereon or used or obtained for use in connection therewith (including, without limitation, all wells, tools, and tubular goods), and accounts (including, without limitation, accounts arising from the sale of production at the wellhead), contract rights, inventory and general intangibles relating thereto or arising therefrom, and all proceeds and products of the foregoing.

B. Each party represents and warrants to the other parties hereto that the lien and security interest granted by such party to the other parties shall be a first and prior lien, and each party hereby agrees to maintain the priority of said lien and security interest against all persons acquiring an interest in Oil and Gas Leases and Interests covered by this agreement and the Operating Agreement by, through or under such party. All parties acquiring an interest in Oil and Gas Leases and Oil and Gas Interests covered by this agreement and the Operating Agreement, whether by assignment, merger, mortgage, operation of law, or otherwise, shall be deemed to have taken subject to the lien and security interest granted by the Operating Agreement and this instrument as to all obligations attributable to such interest under this agreement and the Operating Agreement whether or not such obligations arise before or after such interest is acquired.

C. To the extent that parties have a security interest under the Uniform Commercial Code of the state in which the Contract Area is situated, they shall be entitled to exercise the rights and remedies of a secured party under the Code. The bringing of a suit and the obtaining of judgment by a party for the secured indebtedness shall not be deemed an election of remedies or otherwise affect the lien rights or security interest as security for the payment thereof. In addition, upon default by any party in the payment of its share of expenses, interest or fees, or upon the improper use of funds by the Operator, the other parties shall have the right, without prejudice to other rights or remedies, to collect from the purchaser the proceeds from the sale of such defaulting party's share of Oil and Gas until the amount owed by such party, plus interest, has been received, and shall have the right to offset the amount owed against the proceeds from the sale of such defaulting party's share of Oil and Gas. All purchasers of production may rely on a notification of default from the non-defaulting party or parties stating the amount due as a result of the default, and all parties waive any recourse available against purchasers for releasing production proceeds as provided in this paragraph.

D. If any party fails to pay its share of expense within one hundred-twenty (120) days after rendition of a statement therefor by Operator the non-defaulting parties, including Operator, shall, upon request by Operator, pay the unpaid amount in the proportion that the interest of each such party bears to the interest of all such parties. The amount paid by each party so paying its share of the unpaid amount shall be secured by the liens and security rights described in this paragraph 3 and in the Operating Agreement, and each paying party may independently pursue any remedy available under the Operating Agreement or otherwise.

E. If any party does not perform all of its obligations under this agreement or the Operating Agreement, and the failure to perform subjects such party to foreclosure or execution proceedings pursuant to the provisions of this agreement or the Operating Agreement, to the extent allowed by governing law, the defaulting party waives any available right of redemption from and after the date of judgment, any required valuation or appraisement of the mortgaged or secured property prior to sale, any available right to stay execution or to require a marshalling of assets and any required bond in the event a receiver is appointed. In addition, to the extent permitted by applicable law, each party hereby grants to the other parties a power of sale as to any property that is subject to the lien and security rights granted hereunder or under the Operating Agreement, such power to be exercised in the manner provided by applicable law or otherwise in a commercially reasonable manner and upon reasonable notice.

F. The lien and security interest granted by this paragraph 3 supplements identical rights granted under the Operating Agreement.

G. To the extent permitted by applicable law, Non-Operators agree that Operator may invoke or utilize the mechanics' or materialmen's lien law of the state in which the Contract Area is situated in order to secure the payment to Operator of any sum due under this agreement and the Operating Agreement for services performed or materials supplied by Operator.

H. The above described security will be financed at the wellhead of the well or wells located on the Contract Area and this Recording Supplement may be filed in the land records in the County or Parish in which the Contract Area is located, and as a financing statement in all recording offices required under the Uniform Commercial Code or other applicable state statutes to perfect the above-described security interest, and any party hereto may file a continuation statement as necessary under the Uniform Commercial Code, or other state laws.

4. This agreement shall be effective as of the date of the Operating Agreement as above recited. Upon termination of this agreement and the Operating Agreement and the satisfaction of all obligations thereunder, Operator is authorized to file of record in all necessary recording offices a notice of termination, and each party hereto agrees to execute such a notice of termination as to the Operator's interest, upon the request of Operator, if Operator has complied with all of its financial obligations.

5. This agreement and the Operating Agreement shall be binding upon and shall inure to the benefit of the parties hereto and their respective heirs, devisees, legal representatives, successors and assigns. No sale, encumbrance, transfer or other disposition shall be made by any party of any interest in the Leases or Interests subject hereto except as expressly permitted under the Operating Agreement and, if permitted, shall be made expressly subject to this agreement and the Operating Agreement and without prejudice to the rights of the other parties. If the transfer is permitted, the assignee of an ownership interest in any Oil and Gas Lease shall be deemed a party to this agreement and the Operating Agreement as to the interest assigned from and after the effective date of the transfer of ownership; provided, however, that the other parties shall not be required to recognize any such sale, encumbrance, transfer or other disposition for any purpose hereunder until thirty (30) days after they have received a copy of the instrument of transfer or other satisfactory evidence thereof in writing from the transferor

or transferee. No assignment or other disposition of interest by a party shall relieve such party of obligations previously incurred by such party under this agreement or the Operating Agreement with respect to the interest transferred, including without limitation the obligation of a party to pay all costs attributable to an operation conducted under this agreement and the Operating Agreement in which such party has agreed to participate prior to making such assignment, and the lien and security interest granted by Article VII.B. of the Operating Agreement and hereby shall continue to burden the interest transferred to secure payment of any such obligations.

6. In the event of a conflict between the terms and provisions of this agreement and the terms and provision of the Operating Agreement, then, as between the parties, the terms and provisions of the Operating Agreement shall control.

7. This agreement shall be binding upon each Non-Operator when this agreement or a counterpart thereof has been executed by such Non-Operator and Operator not withstanding that this agreement is not then or thereafter executed by all of the parties to which it is tendered or which are listed on Exhibit "a" as owning an interest in the Contract Area or which own, in fact, an interest in the Contract Area. In the event that any provision herein is illegal or unenforceable, the remaining provisions shall not be affected, and shall be enforced as if the illegal or unenforceable provision did not appear herein.

8. Other provisions.

IN WITNESS WHEREOF, this agreement shall be effective as of the _____ day of _____________, 19___.

ATTEST OR WITNESS:	OPERATOR
	______________________
	______________________
______________________	By ______________________
	Type or print name
	Title:______________________
	Date:______________________
______________________	Address:______________________

ATTEST OR WITNESS:	NON-OPERATOR
	______________________
	______________________
______________________	By ______________________
	Type or print name
	Title:______________________
	Date:______________________
______________________	Address:______________________

ATTEST OR WITNESS:	
	______________________
	______________________
______________________	By ______________________
	Type or print name
	Title:______________________
	Date:______________________
______________________	Address:______________________

ATTEST OR WITNESS:	
	______________________
	______________________
______________________	By ______________________
	Type or print name
	Title:______________________
	Date:______________________
______________________	Address:______________________

ATTEST OR WITNESS:	
	______________________
	______________________
______________________	By ______________________
	Type or print name
	Title:______________________
	Date:______________________
______________________	Address:______________________

ACKNOWLEDGMENTS

NOTE:

The following forms of acknowledgment are the short forms approved by the Uniform Law on Notarial Acts. The validity and effect of these forms in any state will depend upon the statutes of that state.

Individual acknowledgment

State of__________________________ §
§ ss.
County of _______________________ §

This instrument was acknowledged before me on ______________________________ by ____________________.

(Seal, if any) ______________________________

Title (and Rank) ________________

My Commission expires: ________

Acknowledgment in representative capacity

State of__________________________ §
§ ss.
County of _______________________ §

This instrument was acknowledged before me on ______________________________ by ______________________ as _________________ of ________________________.

(Seal, if any) ______________________________

Title (and Rank) ________________

My Commission expires: ________

APPENDIX 10: COPAS ACCOUNTING PROCEDURE EXHIBIT

COPAS — 1995
Recommended by the Council
of Petroleum Accountants Societies

EXHIBIT " "

Attached to and made a part of ____

____

ACCOUNTING PROCEDURE
JOINT OPERATIONS[1]

I. GENERAL PROVISIONS

1. DEFINITIONS

"Joint Property" shall mean the real and personal property subject to the agreement to which this Accounting Procedure is attached.
"Joint Operations" shall mean activities required to handle specific operating conditions and problems for the exploration, development, production, protection, maintenance, abandonment, and restoration of the Joint Property.
"Joint Account" shall mean the account showing the charges paid and credits received in the conduct of the Joint Operations and that are to be shared by the Parties.
"Operator" shall mean the Party designated to conduct the Joint Operations.
"Non-Operators" shall mean the Parties to this agreement other than the Operator.
"Material" shall mean personal property, equipment, supplies, or consumables acquired or held for use on the Joint Property.
"Controllable Material" shall mean Material that at the time is so classified in the Material Classification Manual as most recently recommended by the Council of Petroleum Accountants Societies (COPAS).
"Parties" shall mean legal entities signatory to the agreement, or their successors or assigns, to which this Accounting Procedure is attached.
"Affiliate" shall mean, with respect to the Operator, any party directly or indirectly controlling, controlled by, or under common control with the Operator.

2. STATEMENTS AND BILLINGS

The Operator shall bill Non-Operators on or before the last day of the month for their proportionate share of the Joint Account for the preceding month. Such bills shall be accompanied by statements that identify the authority for expenditure, lease or facility, and all charges and credits summarized by appropriate categories of investment and expense. Controllable Material shall be summarized by major

Material classifications. Intangible drilling costs and audit exceptions shall be separately and clearly identified.

3. ADVANCES AND PAYMENTS BY NON-OPERATORS

A. If gross expenditures for the Joint Account are expected to exceed $_________ in the next succeeding month's operations, the Operator may require the Non-Operators to advance their share of the estimated cash outlay for the month's operations. Unless otherwise provided in the agreement, any billing for such advance shall be payable within 15 days after receipt of the advance request or by the first day of the month for which the advance is required, whichever is later. The Operator shall adjust each monthly billing to reflect advances received from the Non-Operators for such month.

B. Each Non-Operator shall pay its proportion of all bills within 15 days of receipt date. If payment is not made within such time, the unpaid balance shall bear interest compounded monthly using the U.S. Treasury three-month discount rate plus 3% in effect on the first day of the month for each month that the payment is delinquent or the maximum contract rate permitted by the applicable usury laws in the state in which the Joint Property is located, whichever is the lesser, plus attorney's fees, court costs, and other costs in connection with the collection of unpaid amounts. Interest shall begin accruing on the first day of the month in which the payment was due.

4. ADJUSTMENTS

A. Payment of any such bills shall not prejudice the right of any Non-Operator to protest or question the correctness thereof; however, all bills and statements (including payout status statements) related to expenditures rendered to Non-Operators by the Operator during any calendar year shall conclusively be presumed to be true and correct after 24 months following the end of any such calendar year, unless within the said period a Non-Operator takes specific detailed written exception thereto and makes claim on the Operator for adjustment.

B. All adjustments initiated by the Operator except those described in (1) through (4) below are limited to the 24-month period following the end of the calendar year in which the original charge appeared or should have appeared on the Joint Account statement or payout status statement. Adjustments made beyond the 24-month period are limited to the following:

(1) a physical inventory of Controllable Material as provided for in Section VII

(2) an offsetting entry (whether in whole or in part), which is the direct result of a specific joint interest audit exception granted by the Operator relating to another property

(3) a government/regulatory audit

(4) working interest ownership adjustments

5. EXPENDITURE AUDITS

A. A Non-Operator, upon notice in writing to the Operator and other Non-Operators, shall have the right to audit the Operator's accounts and records relating to the Joint Account for any calendar year within the 24-month period following the end of such calendar year; however, conducting an audit shall not extend the time for the taking of written exception to and the adjustment of accounts as provided for in Paragraph 4 of this Section I. Where there are two or more Non-Operators, the Non-Operators shall make every reasonable effort to conduct a joint audit in a manner that will result in a minimum of inconvenience to the Operator. The Operator shall bear no portion of the Non-Operators' audit cost incurred under this paragraph unless agreed to by the Operator. The audits shall not be conducted more than once each year without prior approval of the Operator, except upon the resignation or removal of the Operator, and shall be made at the expense of those Non-Operators approving such audit. The lead audit company's audit report shall be issued within 180 days after completion of the audit field work; however, the 180-day time period shall not extend the 24-month requirement for taking specific detailed written exception as required in Paragraph 4.A. above. All claims shall be supported with sufficient documentation. Failure to issue the report within the prescribed time will preclude the Non-Operator from taking exception to any charge billed within the time period audited.

A timely filed audit report or any timely submitted response thereto shall suspend the running of any applicable statute of limitations regarding claims made in the audit report. While any audit claim is being resolved, the applicable statute of limitations will be suspended; however, the failure to comply with the deadlines provided herein shall cause the statute to commence running again.

B. The Operator shall allow or deny all exceptions in writing to an audit report within 180 days after receipt of such report. Denied exceptions should be accompanied by a substantive response. Failure to respond to an exception with substantive information on denials within the time provided will result in the Operator paying interest on that exception, if ultimately granted, from the date of the audit report. The interest charged shall be calculated in the same manner as used in Section I, Paragraph 3.B.

C. The lead audit company shall reply to the Operator's response to an audit report within 90 days of receipt, and the Operator shall reply to the lead audit company's follow-up response within 90 days of receipt. If the lead audit company does not provide a substantive response to an exception within 90 days, that unresolved audit exception will be disallowed. If the Operator does not provide a substantive response to the lead auditor's follow-up response within 90 days, that unresolved audit exception will be allowed and credit given the Joint Account.

D. The lead audit company or Operator may call an audit resolution conference for the purpose of resolving audit issues/exceptions that are outstanding at least 18 months after the date of the audit report. The meeting will require one month's written notice to the Operator and all audit participants, be held at the Operator's office or other mutually agreed upon location, and require the attendance of representatives of the Operator and each audit participant responsible for the area(s) in which the exceptions are based and who have authority to resolve issues on behalf of their company. Any Party who fails to attend the resolution conference shall be bound by any resolution reached at the conference. The lead audit company will coordinate the response/position of the Non-Operators and continue to maintain its traditional role throughout the audit resolution process.

Attendees will make good faith efforts to resolve outstanding issues, and each Party will be required to present substantive information supporting its position. An audit resolution conference may be held as often as agreed to by the Parties. Issues unresolved at one conference can be discussed at subsequent conferences until each such issue is resolved.

6. AFFILIATES

Charges to the Joint Account for any services or Materials provided by an Affiliate shall not exceed average commercial rates for such services or Materials.

Unless otherwise indicated below, Affiliates performing services or providing Materials for Joint Operations shall provide the Operator with written agreement to make their records relating to the work performed for the Joint Account available for audit upon request by a Non-Operator under this Accounting Procedure. These records shall include, but not be limited to, invoices, field work tickets, equipment use records, employee time reports, and payroll summaries relating to the work performed for the Joint Account. All audits will be conducted pursuant to Section I, Paragraph 5.

☐ The Parties agree that records relating to the work performed by Affiliates will **not** be made available for audit.

7. APPROVAL BY PARTIES

An affirmative vote of ______ or more Parties having a combined working interest of ________ percent (__%) shall be required for all items in this Accounting Procedure requiring approval by the Parties. This vote shall be taken in writing, in a meeting, or by telephone and results shall be binding on all Parties. All votes must be confirmed in writing by each Party to the Operator within two business days. The Operator shall give notice to all Parties of the results.

8. AMENDMENT OF RATES

All rates provided in Fixed Rate (Section II, Paragraph 1), Facilities (Section IV, Paragraph 1), and/or Overhead (Section V, Paragraph 1) shall be adjusted each year as of the first day of the production month of April following the effective date of the agreement to which this Accounting Procedure is attached. The adjustment shall be computed by multiplying the rate currently in use by the percentage increase or decrease recommended by COPAS each year. The adjusted rates shall be the rates currently in use, plus or minus the computed adjustment.

The Operator may, at intervals of at least two years, elect to review the costs associated with any fixed rate and calculate a new rate. At intervals of at least four years, Non-Operators with 50% or more of the Non-Operators' working interest may challenge any rate subject to this provision provided such challenge is supported by factual data. If a rate is so challenged, the Operator shall calculate a new rate. The calculation of any new rate shall be in accordance with COPAS recommendations or other procedures approved by the Parties. The new rate shall then be proposed for approval by the Parties.

II. METHOD OF CHARGES TO JOINT ACCOUNT

The Operator shall charge the Joint Account for the costs of Joint Operations in accordance with only one of the following options. The method of charges to the Joint Account may be changed if approved by the Parties in accordance with Section I, Paragraph 7.

1. ☐ FIXED RATE

A fixed rate of $_____ per month per active well

Active wells are those wells that qualify for a producing overhead charge as specified in Section V, Paragraph 1.A.(3) of this procedure.

The fixed rate will compensate the Operator for all costs applicable to Joint Operations except for royalties, ad valorem taxes, and production/severance taxes paid by the Operator for the Joint Operations and except downhole well work, Controllable Material, and all projects that qualify for drilling, construction, and/or catastrophe overhead as specified in Section V of this procedure. These exception costs shall be charged as specified in Sections III, IV, and V of this procedure.

2. ☐ COSTS

Costs as specified in Sections III, IV, and V of this procedure

III. COSTS INCURRED ON THE JOINT PROPERTY

The Operator shall charge the Joint Account for the following items less discounts taken, which are incurred on the Joint Property for Joint Operations. Employees and contract personnel who spend substantially all their time in offices that are not Joint Property are not chargeable under this Section while working in those offices.

1. RENTALS AND ROYALTIES

Lease rentals and royalties paid by the Operator

2. LABOR

Salaries and wages of the Operator's employees directly employed on the Joint Property in the conduct of Joint Operations or while in transit to/from the Joint Property, provided such costs are excluded from the calculation of overhead rates in Section V

Other expenses associated with these employees to the extent the employees' salaries and wages are chargeable are also chargeable as follows:

A. The Operator's cost of holiday, vacation, sickness, and disability benefits and other customary allowances available to all employees, but specifically excluding severance compensation programs and all employee relocation expenses

Such costs may be charged on a "when and as-paid basis" or by "percentage assessment" on the amount of salaries and wages chargeable to the Joint Account. If percentage assessment is used, the rate shall be based on the Operator's recent cost experience.

B. Expenditures or contributions made pursuant to assessments imposed by governmental authority incurred by the Operator associated with salaries, wages, and benefits charged to the Joint Account

C. Reimbursable travel, meals, and lodging of these employees

D. Government-mandated training

This training charge shall include the wages, salaries, training course cost, and reimbursable travel, meals, and lodging incurred during the training session. The cost of the training course will be limited to prevailing commercial rates.

E. The Operator's cost of established plans for employees' benefits as described in COPAS Interpretation No. 11 determined by applying the employee benefits percent most recently published by COPAS to the chargeable salaries and wages

3. MATERIAL

Materials purchased or furnished by the Operator for use on the Joint Property as provided under Section VI

Only such Materials shall be purchased for or transferred to the Joint Property as may be required for immediate use and are reasonably practical and consistent with efficient and economical operations. The accumulation of surplus stocks shall be avoided.

4. TRANSPORTATION

Transportation of company labor, contract personnel, and Material necessary for the Joint Operations but subject to the following limitations:

A. If Material is moved to the Joint Property from the Operator's warehouse or other properties, no charge shall be made to the Joint Account for a distance greater than the distance from the nearest supply store where like Material is normally available, or railway receiving point nearest the Joint Property, unless agreed to by the Parties.

B. If surplus Material is moved to the Operator's warehouse or other storage point, no charge shall be made to the Joint Account for a distance greater than the distance to the nearest supply store where like Material is normally available, or railway receiving point nearest the Joint Property unless agreed to by the Parties. No charge shall be made to the Joint Account for moving Material to other properties, unless agreed to by the Parties.

C. In the application of subparagraphs A and B above, the option to equalize or charge actual trucking costs is available when the actual charge is less than the amount most recently recommended by COPAS, excluding accessorial charges. Examples of accessorial charges are listed in Bulletin 21.

D. No charge shall be made for transportation costs associated with relocating employees, including the costs of moving their household goods and personal effects, unless agreed to by the Parties.

5. SERVICES

The cost of contract services, equipment, and utilities provided by sources other than the Operator.

6. EQUIPMENT FURNISHED BY THE OPERATOR

A. Equipment located on the Joint Property owned by the Operator shall be charged to the Joint Account at the average prevailing commercial rate for such equipment. If an average commercial rate is used to bill the Joint Account, the Operator shall adequately document and support such rate and shall periodically review and update the rate.

B. In lieu of charges in Paragraph 6.A. above, or if a prevailing commercial rate is not available, equipment owned by the Operator will be charged to the Joint Account at the Operator's actual cost. Such costs may include all expenses that would be chargeable pursuant to this Section III if such equipment were jointly owned, depreciation using straight line depreciation method, interest on investment (less gross accumulated depreciation) not to exceed ___% per annum, and an element of the estimated cost to dismantle and abandon the equipment. Charges for depreciation will no longer be allowable once the equipment has been fully depreciated. Actual cost shall not exceed the average prevailing commercial rate.

C. When applicable for Operator-owned or -leased motor vehicles, the Operator shall use rates published by the Petroleum Motor Transport Association or such other organization recognized by COPAS as the official source of such rates. When such rates are not available, the Operator shall comply with the provisions of Paragraph A or B above.

7. DAMAGES AND LOSSES TO JOINT PROPERTY

All costs or expenses necessary for the repair or replacement of Joint Property resulting from damages or losses incurred, except those resulting from the Operator's gross negligence or willful misconduct

8. TAXES AND PERMITS

All taxes and permits of every kind and nature, including penalties and interest, assessed or levied upon or in connection with the Joint Property, or the production therefrom, and which have been paid by the Operator for the benefit of the Parties

If ad valorem taxes paid by the Operator are based in whole or in part upon separate valuations of each Party's working interest, then notwithstanding any contrary provisions, the charges to Parties will be made in accordance with the tax value generated by each Party's working interest.

9. INSURANCE

Net premiums paid for insurance required to be carried for the protection of the Parties

If Joint Operations are conducted at locations where the Operator acts as self-insurer, the Operator shall charge the Joint Account manual rates as regulated by the state in which the Joint Property is located, or in the case of offshore operations, the adjacent state as adjusted for offshore operations by the U.S. Longshoreman and Harbor Workers (USL&H) or Jones Act surcharge, as appropriate.

10. COMMUNICATIONS

Cost of acquiring, leasing, installing, operating, repairing, and maintaining communication systems

11. ECOLOGICAL AND ENVIRONMENTAL

Costs of surveys as well as pollution containment, actual control, and resulting responsibilities as required by applicable laws or resulting from statutory regulations

12. ABANDONMENT AND RECLAMATION

Costs incurred for abandonment and reclamation of the Joint Property, including costs required by governmental or other regulatory authority

IV. COSTS INCURRED OFF THE JOINT PROPERTY

The Operator shall charge the Joint Account for the following items, which are incurred off the Joint Property for Joint Operations.

1. FACILITIES

A. PRODUCTION-HANDLING FACILITIES

(1) ALLOCATED

The Operator shall allocate charges to the Joint Account on an equitable and consistent basis for facilities that handle substances extracted from or injected into the real property subject to the agreement to which this Accounting Procedure is attached if such facilities are not listed in Paragraph (2) below or covered by a separate facility agreement. Allocable charges for such facilities that are leased or rented shall be at the Operator's cost. All allocable charges for such facilities owned by the Operator shall be operating costs as defined in Section III incurred on the facility site plus depreciation, interest on investment (less gross accumulated depreciation) not to exceed ____% per annum, and estimated dismantling and abandonment costs. Charges for depreciation will no longer be allowable once the equipment has been fully depreciated. Such rates shall not exceed average commercial rates prevailing in the area of the Joint Property.

In lieu of charges in Paragraph 1.A.(1) above for Operator-owned facilities, the Operator may elect to charge average commercial rates prevailing in the immediate area of the Joint Property. If average commercial rates are used, the Operator shall adequately document and support the rates.

(2) FIXED RATE
The Operator shall charge the Joint Account monthly for the following facilities based on the rates and units provided:

FACILITY TYPE (function performed)	**FIXED RATE**	**UNITS (Well, MCF, BOE, etc.)**
____________________	____________________	____________________
____________________	____________________	____________________
____________________	____________________	____________________
____________________	____________________	____________________

B. OTHER FACILITIES
The Operator shall charge the Joint Account for use of other facilities not covered by Section IV, Paragraph 1.A. (such as shore bases, field offices, telecommunication equipment, and computer equipment) as listed below or if subsequently approved by the Parties. (Choose and complete only one methodology for each facility type.)

FACILITY TYPE (function performed)	**AVG. COM-MERCIAL RATES**	**FIXED RATE BASIS**		**ACTUAL COST ALLOCATION**
		RATE	UNITS (Well, MCF, BOE, etc.)	BASIS
________________		_____	________________	____________
________________			_____	____________
________________		________________		____________
________________		_____	________________	____________
1 ________________		_____	________________	____________
_	1	1 _____	________________	1

If the Actual Cost Allocation method is chosen, all allocable charges for such facilities owned by the Operator shall be operating costs as defined in Section III incurred on the facility site plus depreciation, interest on investment (less gross accumulated depreciation) not to exceed ___% per annum, and estimated dismantling and abandonment costs. Charges for depreciation will no longer be allowable once the equipment has been fully depreciated. Such rates shall not exceed average commercial rates prevailing in the area of the Joint Property.

2. ECOLOGICAL AND ENVIRONMENTAL

Ecological and environmental costs are those that arise from compliance with governmental or regulatory requirements or prudent operations. These costs that are incurred off the Joint Property shall be

☐ allocated directly to the Joint Account
☐ included in the Overhead rates provided in Section V

3. LEGAL EXPENSE

The Operator may not charge for services of the Operator's legal staff or fees and expense of outside attorneys unless approved by the Parties in writing. Other expenses of handling, settling, or otherwise discharging litigation, claims, liens, title examinations, and curative work necessary to protect or recover the Joint Property shall be chargeable.

4. TRAINING

Training mandated by governmental authorities for those employees who would be chargeable to the Joint Account under Section III, Paragraph 2, of this Accounting Procedure if they were not attending the training shall be chargeable to the Joint Account. This training charge shall include costs as defined in Section III, Paragraph 2.D. but incurred off the Joint Property.

5. ENGINEERING, DESIGN, AND DRAFTING

Engineering, design, and drafting costs associated with major construction or catastrophes, as defined in Section V, Paragraph 2, of this Accounting Procedure, may be charged to the Joint Account only when the Operator elects to charge overhead for major construction or catastrophes per Section V, Paragraph 2.B. Such charges shall be determined in a manner consistent with those defined in Section III, Paragraphs 2 and 5.

V. OVERHEAD

The Operator shall be compensated for costs not chargeable in Section III (Costs Incurred On The Joint Property) or Section IV (Costs Incurred Off The Joint Property) that are incurred in connection with and in support of Joint Operations.

1. OVERHEAD—DRILLING AND PRODUCING OPERATIONS

As compensation for overhead in connection with drilling and producing operations, the Operator shall charge on either a
☐ Fixed Rate Basis, Paragraph 1.A., or
☐ Percentage Basis, Paragraph 1.B.

A. OVERHEAD—FIXED RATE BASIS

(1) The Operator shall charge the Joint Account at the following rates per well month:
Drilling well rate per month $_____________(Prorated for less than a full month)
Producing well rate per month $___________

(2) Application of overhead—drilling well rate shall be as follows:

(a) Charges for onshore drilling wells shall begin on spud date and terminate on the date the drilling or completion equipment is released, whichever occurs later. Charges for offshore drilling wells shall begin on the date drilling or completion equipment arrives on location and terminate on the date the drilling or completion equipment moves off location or the rig is released, whichever occurs first. No charge shall be made during suspension of drilling or completion operations for 15 or more consecutive calendar days.

(b) Charges for wells undergoing any type of workover, recompletion, or abandonment for a period of five consecutive work days or more shall be made at the drilling well rate. Such charges shall be applied for the period from the date workover operations, with the rig or other units used in workover, commence through the date of the rig or other unit release, except that no charges shall be made during suspension of operations for 15 or more consecutive calendar days.

(3) Application of overhead—producing well rate shall be as follows:

(a) An active well completion for any portion of the month shall qualify for a one-well charge for the entire month. An active completion is one that is
[1] produced,
[2] injected into for recovery or disposal, or
[3] used to obtain a water supply to support production operations.

(b) Each active completion in a multi-completed well in which production is not commingled downhole shall qualify for a one-well charge providing each completion is considered a separate well by the governing regulatory authority.

(c) A one-well charge shall be made for the month in which plugging and abandonment operations are completed on any well. This one-well charge shall be made whether or not the well has produced except when the drilling well rate applies.

(d) All wells not meeting the criteria set forth in this Paragraph A (3) (a), (b), or (c) shall not qualify for a producing overhead charge.

B. OVERHEAD—PERCENTAGE BASIS

(1) The Operator shall charge the Joint Account at the following rates:

(a) Development rate ____________ percent (___%) of the cost of development of the Joint Property exclusive of costs provided under Section IV, Paragraph 3 and all salvage credits.

(b) Operating rate _____________ percent (___%) of the cost of operating the Joint Property exclusive of costs provided under Section III, Paragraph 1 and Section IV, Paragraph 3; all salvage credits; the value of injected substances purchased for secondary recovery; and all taxes and assessments that are levied, assessed, and paid upon the mineral interest in and to the Joint Property

(2) Application of overhead—percentage basis shall be as follows:

(a) Development shall include all costs in connection with

[1] drilling, redrilling, plugging back, or deepening of any or all wells

[2] workover operations requiring a period of five consecutive work days or more on any or all wells

[3] preliminary expenditures necessary in preparation for drilling

[4] expenditures incurred in abandoning when the well is not completed as a producer

[5] original construction or installation of fixed assets, expansion of fixed assets, and any other project clearly discernible as a fixed asset, except major construction as defined in Section V, Paragraph 2

(b) Operating shall include all other costs in connection with Joint Operations except that catastrophe costs shall be assessed overhead as provided in Section V, Paragraph 2.

2. OVERHEAD—MAJOR CONSTRUCTION AND CATASTROPHES

Major construction is defined as any project in excess of $_____ required for the construction and installation of fixed assets, the expansion of fixed assets, or in the dismantling for abandonment of fixed assets as required for the development and operation of the Joint Property.

Catastrophe is defined as a calamitous event bringing damage, loss, or destruction resulting from a single occurrence requiring expenditures in excess of $_____ to restore the Joint Property to the equivalent condition that existed prior to the event causing the damage.

To compensate the Operator for overhead costs incurred in connection with major construction and catastrophes, the Operator shall either negotiate a rate prior to beginning the work or shall charge the Joint Account for overhead based on the following rates:

A. If the Operator absorbs engineering, design, and drafting costs related to the project, the overhead assessment will be _____% of total project costs.

B. If the Operator charges engineering, design, and drafting costs related to the project directly to the Joint Account, the overhead assessment will be _____% of total project costs.

For each project, the Operator shall provide advance notice to the Non-Operators in writing if option A or B above will be used for calculating construction or catastrophe overhead. For purposes of calculating overhead, the cost of drilling and workover wells shall be excluded and catastrophe expenditures to which these rates apply shall not be reduced by insurance recoveries. Overhead assessed under the construction and catastrophe provisions shall be in lieu of all other overhead provisions.

VI. MATERIAL PURCHASES, TRANSFERS, AND DISPOSITIONS

The Operator is responsible for Joint Account Material and shall make proper and timely charges and credits for direct purchases, transfers, and dispositions. The Operator normally provides all Material for use on the Joint Property but does not warrant the Material furnished. At the Operator's option, Material may be supplied by Non-Operators.

1. DIRECT PURCHASES

Direct purchases shall be charged to the Joint Account at the price paid by the Operator after deduction of all discounts received. A direct purchase is determined to occur when an agreement is made between an Operator and a third party for the acquisition of Materials for a specific well site or location. Material provided by the Operator under "vendor stocking programs," where the initial use is for a Joint Property and title of the Material does not pass from the vendor until usage, is considered a direct purchase. If Material is found to be defective or is returned to the vendor for any other reason, credit shall be passed to the Joint Account when adjustments have been received by the Operator from the manufacturer, distributor, or agent.

2. TRANSFERS

A transfer is determined to occur when the Operator furnishes Material from its storage facility or from another operated property. Additionally, the Operator has assumed liability for the storage costs and changes in value and has previously secured and held title to the transferred Material. Similarly, the removal of Material from a Joint Property to the Operator's facility or to another operated property is also considered a transfer. Material that is moved from the Joint

Property to a temporary storage location pending disposition may remain charged to the Joint Account and is not considered a transfer.

A. PRICING

The value of Material transferred to/from the Joint Property should generally reflect the market value on the date of transfer. Transfers of new Material will be priced using one of the following new Material bases:

(1) Published prices in effect on the date of movement as adjusted by the appropriate COPAS Historical Price Multiplier (HPM) or prices provided by the COPAS Computerized Equipment Pricing System (CEPS)

The HPMs and the associated date of published price to which they should be applied will be published by COPAS periodically.

(a) For oil country tubulars and line pipe, the published price shall be based upon eastern mill (Houston for special end) carload base prices effective as of the date of movement, plus transportation cost as defined in Section VI, Paragraph 2.B.

(b) For other Material, the published price shall be the published list price in effect at the date of movement, as listed by a supply store nearest the Joint Property or point of manufacture, plus transportation costs as defined in Section VI, Paragraph 2.B.

(2) A price quotation that reflects a current realistic acquisition cost may be obtained from a supplier/manufacturer.

(3) Historical purchase price may be used, providing it reflects a current realistic acquisition cost on the date of movement. Sufficient price documents should be available to Non-Operators for purposes of verifying Material transfer valuation.

(4) As agreed to by the Parties

B. FREIGHT

Transportation costs should be added to the Material transfer price based on one of the following:

(1) Transportation costs for oil country tubulars and line pipe shall be calculated using the distance from eastern mill to the railway receiving point nearest the Joint Property based on the carload weight basis as recommended by COPAS in Bulletin 21 and current interpretations.

(2) Transportation costs for special mill items shall be calculated from that mill's shipping point to the railway receiving point nearest the Joint Property. For transportation costs from other than eastern mills, the

30,000-pound Specialized Motor Carriers interstate truck rate shall be used. Transportation costs for macaroni tubing shall be calculated based on the Specialized Motor Carriers rate per weight of tubing transferred to the railway receiving point nearest the Joint Property.

(3) Transportation costs for special end tubular goods shall be calculated using the 30,000-pound Specialized Motor Carriers interstate truck rate from Houston, Texas, to the railway receiving point nearest the Joint Property.

(4) Transportation costs for Material other than that described in Section VI, Paragraphs 2.B(1) through (3), if applicable, shall be calculated from the supply store or point of manufacture, whichever is appropriate, to the railway receiving point nearest the Joint Property.

C. CONDITION

(1) Condition "A"—New and unused Material in sound and serviceable condition shall be charged at one hundred percent of the price as determined in Section VI, Paragraphs 2.A and B. Material transferred from the Joint Property that was not placed in service on the Joint Property shall be credited as charged without gain or loss. Any unused Material that was charged to the Joint Account through a direct purchase will be credited to the Joint Account at the original cost paid. All refurbishing costs necessary to correct handling or transportation damages and other related costs will be borne by the divesting property. The Joint Account is responsible for Material preparation, handling, and transportation costs for new and unused Material charged to the property either through a direct purchase or transfer. Any preparation costs performed, including any internal or external coating and wrapping, will be credited on new Material provided these costs were not repeated for the receiving property.

(2) Condition "B"—Used Material in sound and serviceable condition and suitable for reuse without reconditioning shall be priced at the condition percentage most recently recommended by COPAS times the price determined by the pricing guidelines in Section VI, Paragraphs 2.A and B. Any cost of reconditioning to return the Material to Condition B will be absorbed by the divesting property.

If the Material was originally charged to the Joint Account as used Material and placed in service on the Joint Property, the Material will be credited at the condition percentage most recently recommended by COPAS times the price as determined in Section VI, Paragraphs 2.A and B.

Used Material transferred from the Joint Property that was not placed in service on the property shall be credited as charged without gain or loss.

(3) Condition "C"—Material that is not in sound and serviceable condition and not suitable for its original function until after reconditioning shall be priced at the condition percentage most recently recommended by COPAS times the price determined in Section VI, Paragraphs 2.A and B. The cost of reconditioning shall be charged to the receiving property provided Condition C value, plus cost of reconditioning, does not exceed Condition B value.

(4) Condition "D"—Other Material that is no longer suitable for its original purpose but usable for some other purpose is considered Condition D Material. Included under Condition "D" is also obsolete items or Material that does not meet original specifications but still has value and can be used in other services as a substitute for items with different specifications. Due to the condition or value of other used and obsolete items, it is not possible to price these items under Section VI, Paragraph 2.A. The price used should result in the Joint Account being charged or credited with the value of the service rendered or use of the Material. In some instances, it may be necessary or desirable to have the Material specially priced as agreed to by the parties.

(5) Condition "E"—Junk shall be priced at prevailing scrap value prices.

D. OTHER PRICING PROVISIONS

(1) Preparations Costs

Costs incurred by the Operator in making Material serviceable including inspection, third party surveillance services, and other similar services will be charged to the Joint Account at prices reflective of the Operator's actual costs of the services. Documentation must be retained to support the cost of service. New coating and/or wrapping may be charged per Section VI, Paragraph 2.A.

(2) Loading and Unloading Costs

Loading and unloading costs related to the movement of the Material to the Joint Property shall be charged in accordance with the methods specified in COPAS Bulletin 21.

3. DISPOSITION OF SURPLUS

Surplus Material is that Material, whether new or used, that is no longer required for Joint Operations. The Operator may purchase, but shall be under no obligation to purchase, the interest of the Non-Operator in surplus Material.

Dispositions for the purpose of this procedure are considered to be the relinquishment of title of the Material from the Joint Property to either a third party, a Non-Operator, or to the Operator. To avoid the accumulation of surplus Materials, the Operator should make good faith efforts to dispose of surplus within 12 months through buy/sale agreements, trade, sale to a third party, division in-kind, or other dispositions as agreed to by the Parties.

An Operator may, through a sale to an unrelated third party or entity, dispose of surplus Material having a gross sale value that is less than or equal to the Operator's expenditure limit as set forth in the Operating Agreement to which this Accounting Procedure is attached without the prior approval of the Non-Operator. If the gross sale value exceeds the Operating Agreement expenditure limit, the disposal must be agreed to by the Parties.

The Operator may dispose of Condition D and E Material under procedures normally utilized by the Operator without prior approval.

4. SPECIAL PRICING PROVISIONS

A. PREMIUM PRICING

Whenever Material is not readily replaceable due to national emergencies, strikes, or other unusual causes over which the Operator has no control, the Operator may charge the Joint Account for the required Material at the Operator's actual cost incurred in providing such Material, in making it suitable for use, and in moving it to the Joint Property provided notice in writing is furnished to Non-Operators of the proposed charge prior to use and to billing Non-Operators for such Material. During premium pricing periods, each Non-Operator shall have the right to furnish in-kind all or part of his share of such Material suitable for use and acceptable to the Operator by so electing and notifying the Operator within ten days after receiving notice from the Operator.

B. SHOP-MADE ITEMS

Shop-made items may be priced using the value of the Material used to construct the item plus labor costs. If the Material is from a scrap or junk account, the Material may be priced at either 25% of the current price as determined in Section VI, Paragraph 2.A, or scrap value, whichever is higher, plus estimated labor costs to fabricate the item.

C. MILL REJECTS

Mill rejects purchased as "limited service" casing or tubing shall be priced at 80% of K-55/J-55 price as determined in Section VI, Paragraphs 2.A and B. Line pipe converted to casing or tubing with casing or tubing couplings attached shall be priced as K-55/J-55 casing or tubing at the nearest size and weight.

VII. INVENTORIES OF CONTROLLABLE MATERIAL

The Operator shall maintain records of Controllable Material charged to the Joint Account, as defined in the COPAS Material Classification Manual, with sufficient detail to perform the physical inventories requested unless directed otherwise by the Non-Operators.

Adjustments to the Joint Account by the Operator resulting from a physical inventory of jointly owned Controllable Material are limited to the six months following the taking of the inventory. Charges and credits for overages or shortages will be valued for the Joint Account based on Condition B prices in effect on the date of physical inventory and determined in accordance with Section VI, Paragraphs 2.A. and B, unless the inventorying Parties can prove another Material condition applies.

1. DIRECTED INVENTORIES

With an interval of not less than five years, physical inventories shall be performed by the Operator upon written request of a majority in working interests of the Non-Operators.

Expenses of directed inventories will be borne by the Joint Account and may include the following:

A. Audit per diem rate for each inventory person in line with the auditor rates determined, adjusted, and published each April by COPAS

The per diem should also be applied to a reasonable number of days for pre-inventory work and for report preparation. The amount of time required for this additional work may vary from inventory to inventory.

B. Actual travel including Operator-provided transportation and personal expenses for the inventory team

C. Reasonable charges for report typing and processing

The Operator is expected to exercise judgment in keeping expenses within reasonable limits. Unless otherwise agreed, costs associated with any post-report follow-up work in settling the inventory will be absorbed by the Non-Operator incurring such costs. Any anticipated disproportionate costs should be discussed and agreed upon prior to commencement of the inventory.

When directed inventories are performed, all Parties shall be governed by such inventory.

2. NON-DIRECTED INVENTORIES

A. OPERATOR INVENTORIES

Periodic physical inventories that are not requested by the Non-Operator may be performed by the Operator at the Operator's discretion. The expenses of conducting such Operator inventories shall not be charged to the Joint Account.

B. NON-OPERATOR INVENTORIES

Any Non-Operator(s) may conduct a physical inventory at reasonable times with prior notification to the Operator. Such inventories shall be conducted at the sole cost and risk of the participating Non-Operator(s).

C. OTHER INVENTORIES

Other physical inventories may be taken whenever there is any sale or change of interest. When possible, the selling Party should notify all other owners 30 days prior to the anticipated closing date. When there is a change in Operator of the Joint Property, an inventory by the former and new Operator should be taken. The expenses of conducting such other inventories shall be charged to the Joint Account.

APPENDIX 11: OTHER REFERENCE SOURCES

COPAS Publications and Videos. The Council of Petroleum Accountants Societies has available COPAS Bulletins, Interpretations, Research Papers, and Guidebooks, videos and other educational resources on petroleum accounting. Information on these resources is available at www.copas.org.

1999 PricewaterhouseCoopers Survey of U.S. Petroleum Accounting Practices. The survey summarizes accounting practices not typically disclosed in annual reports. The survey participants are categorized in three ways (1) Integrated vs Independent, (2) Successful Efforts vs Full Cost, and (3)Public vs Private. For copies of the latest survey, contact the Institute of Petroleum Accounting at www.unt.edu/ipa. Telephone: (940) 565-3170.

Petroleum Accounting and Financial Management Journal published by the Institute of Petroleum Accounting, University of North Texas (www.unt.edu/ipa). Begun in the Spring of 1982, the journal is published three times a year and periodically publishes a topical index, listing past articles. The issues contain articles on current developments in the extractive industries, generally the pronouncements and actions by the American Institute of Certified Public Accountants, the Financial Accounting Standards Board, the Securities and Exchange Commission, and other authoritative accounting and financial groups; an industry tax update; a section entitled *Accounting Forum* geared to answering questions that have a broad interest in this industry, and several articles on various timely domestic and international industry issues by well-known and respected authors in the industry.

Audit and Accounting Guide: Audits of Entities with Oil and Gas Producing Activities *by the American Institute of Certified Public Accountants (AICPA).* With conforming changes as of May 1, 1998, the Guide presents the 1986 recommendations of the AICPA's defunct Oil and Gas Committee on the application of generally accepted auditing standards to audits of financial statements. The guide offers descriptions of financial accounting and reporting principles and practices for entities with oil and gas producing activities. The Guide's Appendix A provides illustrative financial statements and supplemental information disclosures.

GLOSSARY

AAPL—American Association of Professional Landmen, formerly the American Association of Petroleum Landmen.

ABANDON—To discontinue attempts to produce oil or gas from a well or lease and to plug the reservoir in accordance with regulatory requirements and recover equipment.

ABSORBER—Field equipment, usually a tower, that removes liquid (oil or water) from gas stream using absorption (as opposed to adsorption). In absorption, the removed liquid changes by mixing with another liquid. In adsorption the removed liquid is unchanged but clinging to the surface of a solid adsorbent such as activated charcoal. A triethylene glycol (TEG) absorber removes water from a gas stream whereby wet gas enters at the bottom, passes through a TEG stream, and exits dry at the top. The *wet* glycol is dried in a reboiler to remove the water.

ACIDIZE—Increase the flow of oil from a well by introducing acid into a carbonate formation (such as limestone) to open passages through which oil can flow into the well bore. Acidizing may be called an *acid job*.

ACQUISITION WELL—A well drilled in exchange for a mineral interest in a property. This is also referred to as an obligation well.

ACRE-FOOT—A reservoir analysis measure of volume equaling 43,560 cubic feet or 7,758 barrels. One acre foot represents the volume that would cover one acre to a depth of one foot.

ACT or **LACT SYSTEM**—See **LACT UNIT**.

***AD VALOREM* TAXES—**Local taxes, such as county and school district taxes, paid and based on the individual property value.

ADSORPTION PLANT—Field equipment for removing liquid from a gas stream by adsorption (as opposed to absorption as explained above for the term **ABSORBER**).

ADVANCE ROYALTY or ADVANCED ROYALTY—Generally, a royalty that must be paid regardless of production and revenue levels, such as a minimum royalty or a shut-in royalty, for which future production royalties may or may not be reduced. In a sense, the lease bonus is an advance royalty, but the term does not usually refer to the bonus.

AFE (AUTHORITY or AUTHORIZATION FOR EXPENDITURE)—A budgeting and approval form used during the planning process for a well about to be drilled (and also used for other projects). It includes an estimate of costs to be incurred in the IDC category and in the tangible equipment category. Costs are shown in total with accompanying breakdowns. The form represents a budget for the project against which actual expenditures are compared and a joint venture form for evidencing agreement by joint interest owners to participate in the budgeted project.

AIR DRILLING—The use of compressed air as a substitute for drilling mud in rotary drilling.

GLOSSARY

AIR/GAS LIFT—Method of raising oil from the formation by injecting air or gas directly into the fluid in the casing.

ALLOWABLE—The government regulated amount of oil or gas that a well or lease can produce during a given time period.

AMI—Area of mutual interest.

ANGLE OF DEFLECTION—In directional drilling, the angle expressed in degrees, at which a well is deflected from the vertical by means of a whipstock or other deflecting tool.

ANNULAR SPACE—The space surrounding a cylindrical object within a cylinder. The space around a pipe suspended in a wellbore is often termed the annulus, and its outer wall may be either the wall of the borehole or the casing.

ANTICLINES—Underground mountain-shaped strata covered with caprock or an impervious layer.

API—Abbreviation for American Petroleum Institute, established in 1920.

API GRAVITY or **°API—**A standard industry measure of gravity (i.e., density) of liquid petroleum product. The formula for API gravity in terms of specific gravity (g) is (141.5 ÷ g at 60°F) – 131.5. Very light crude oils and gasoline have API gravity in the range of 50° to 60°. Light crude oils' API gravity range from about 35° to 45°. Heavy (dense) crude oils API Gravity range from about 6° to 25°. Water has an API gravity of 10° and a specific gravity of 1.

API WELL NUMBER—A distinct twelve digit number assigned to a U.S. well. Digits 1 and 2 are state codes, digits 3 through 5 are county/parish or offshore codes, digits 6 through 10 identify the well, and digits 11 and 12 identify special well conditions such as a sidetracking.

APO—After Payout. Used with working interests and net revenue interests to indicate ownership after payout (see PAYOUT) versus BPO, before payout.

AREA OF INTEREST—A federal income tax term used in allocating GEOPHYSICAL AND GEOLOGICAL COSTS (q.v.) to certain properties. A large-scale geophysical survey may indicate several areas of interest. The costs of the survey must be allocated to each area of interest, and when leases are obtained therein, the geophysical costs become part of the basis of the property

AREA OF MUTUAL INTEREST—A term found in joint venture agreements designating a geographic area around the joint venture's leases. The agreement provides that any joint venture participant obtaining new property rights within the AMI must offer such rights to the joint venture.

GLOSSARY

ASSIGNEE—In law generally, a transferee; a recipient of an interest in property or a contract. In oil and gas law, the term commonly means, but is not limited to, the transferee of an oil and gas lease.

ASSIGNMENT—In law generally, a transfer. In oil and gas law, usually a transfer of a property interest or of a contract. The most common usage refers to the assignment of an oil and gas lease.

ASSIGNOR—In law generally, a transferor; the party who conveys a right, title or interest in property or a contract. In oil and gas law, the term commonly means, but is not limited to, the conveyor of an oil and gas lease.

ASSOCIATED GAS—Natural gas, occurring in the form of a gas cap, overlying an oil zone (as opposed to nonassociated gas [from a gas reservoir with no oil] and dissolved [or *casinghead* or *solution*] contained in the reservoir's crude oil gas).

AUTOMATIC CUSTODY TRANSFER SYSTEM —See **LACT UNIT.**

BACK-IN INTEREST—An ORRI or carried interest which converts to a working interest at a specific time or event, such as one year from well completion or completion of a payout provision (e.g., 300 percent payout).

BAFFLE—A device which changes the direction of flow of fluids.

BARREL (BBL)—A standard measure of volume for crude oil and liquid petroleum products. One barrel equals 42 U.S. gallons.

BASIC SEDIMENT & WATER (OR BS&W)—Impurities contained in produced oil. Purchasing companies will ordinarily not accept oil having more than one percent of BS&W. If the fluid as produced contains more than this proportion of foreign matter, some of the impurities such as sand and water may be removed from the crude by settling in the bottom of the lease storage. The impurities gradually settle and thicken in the bottom of the tank as an emulsion.

BATTERY—Group of lease storage tanks.

BBL—Bbl or bbl, the abbreviation for barrel.

BBL/D—Barrels per day.

BCF—Billion Cubic Feet.

BEAM WELL—A well from which oil is lifted by use of a walking beam pump unit.

BEHIND PIPE RESERVES—Oil or gas reserves (proved or unproved) that cannot be produced until future perforation of casing at the depth of that reservoir. Generally these are reserves in reservoir(s) above the currently producing zone.

GLOSSARY

BENCHMARK CRUDE—The oil for an area used to set the standard for quality and setting the price. For the United States, it is West Texas Intermediate used for instance, in crude oil futures contracts on the New York Mercantile Exchange. OPEC's benchmark is Saudi Arabian Light; Europe's benchmark is North Sea Brent.

BENCHMARK PRICING—An agreement between parties to sell and buy oil or gas in the future at a percentage or function of a future published oil or gas price routinely determined by another party. The benchmark might be another party's posted price for crude oil (or a published average spot gas price) at a specified location on the date of sale. One of four methods used to price gas or five methods for oil for Federal Royalty purposes. Generally used in processed gas sales.

BHP—Bottom Hole Pressure (or sometimes Brake Horse Power).

BIT—The cutting or boring element used in drilling oil and gas wells. Bits are designed on two basic and different principles: the cable tool bit, which moves up and down to pulverize; and the rotary bit, which revolves to grind.

BLEED—To drain off liquid or gas generally slowly, through a valve called a bleeder.

BLOW BY—The escape of gas with the liquid from a separator.

BLOWOUT OR BLOW OUT—A sudden, violent expulsion of oil, gas and mud (and sometimes water) from a drilling well, followed by an uncontrolled flow from the well. It occurs when high pressure gas is encountered in the hole and sufficient precautions, such as increasing the weight of the mud, have not been taken.

BLOWOUT PREVENTER—A heavy casinghead control filled with special gates or rams which can be closed around the drill pipe, or which completely close the top of the casing.

BLUE SKY LAW—A statute which regulates the issuance and sale of securities. The term is usually restricted to state statutes; the corresponding federal statute and regulations are the Federal Securities Act and the S.E.C. regulations.

BONUS—The consideration paid by the lessee to the lessor upon execution of an oil and gas lease.

BOPD—Barrels of Oil Per Day.

BOREHOLE—The wellbore; the hole made by drilling or boring a well.

BOTTOM-HOLE CONTRIBUTIONS—Money or property paid to an operator for use in drilling a well on property in which the payer has no property interest. The contributions are payable when the well reaches a predetermined depth, regardless of whether the well is productive or nonproductive. The payer may receive proprietary information on the well's potential productivity.

GLOSSARY

BOTTOM-HOLE LETTER OR CONTRACT—An agreement by which an operator contemplating the drilling of a well on his own land secures the promise of another to contribute to the cost of the well, usually in return for proprietary information on the well's potential productivity. In contrast to the dry hole letter, the bottom-hole letter requires payment upon drilling and testing the well at a specified depth or formation even if the well does not produce.

BOTTOM-HOLE PRESSURE—The reservoir or rock pressure at the bottom of the hole, whether measured under flowing conditions or not. If measured under flowing conditions, pressure readings are usually taken at different rates of flow in order to compute a theoretical value for maximum productivity. Decline in pressure furnishes a guide, in some reservoirs, to the amount of depletion from the reservoir and the amount of remaining proved reserves.

BPO—Before Payout. Used with working interests and net revenue interests to indicate ownership before payout (see **PAYOUT**) versus APO, after payout.

BRITISH THERMAL UNIT (BTU)—A measure of the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit. The energy values of petroleum products per barrel (million Btu/bbl) are approximately as follows: average U.S. crude petroleum--5.8; residual fuel oil--6.29; distillate fuel oil--5.83; gasoline--5.35; jet fuel (kerosene type)--5.67; jet fuel (naphtha type)--5.36; kerosene--5.67. Dry natural gas averages 1.03 mmBtu/mcf; wet natural gas 1.110 mmBtu/mcf. Natural gas in pipelines has from .95 to 1.05 mmBtu/mcf. An average oil barrel has the energy content of approximately 5.6 mcf dry natural gas of 1.03 mmBtu/mcf.

BS or **BS&W**—See **BASIC SEDIMENT AND WATER.**

BTU—See **BRITISH THERMAL UNIT**.

BULLET PERFORATOR—A perforator that fires bullets through the casing in order to provide holes through which the well fluids may enter.

BUTANE—A hydrocarbon gas (C_4H_{10}) extracted as a *natural gas liquid* from natural gas, and used as a gasoline ingredient increasing volatility and improving cold engine starts. Liquefied petroleum gas may contain some butane but is generally propane.

CABLE-TOOL DRILLING—Using a cable tool rig to drill a well by pounding the chisel-shaped bit up and down thereby pulverizing the rock. This original well drilling method is now largely replaced by rotary drilling where the drill bit rotates to grind, rather than pulverize, the rock.

CAPACITY—The maximum volume a well is capable of producing in a unit of time. Generally expressed per hour. Capacity may also refer to a maximum volume of fluid for a given container or reservoir.

CARRIED INTEREST AGREEMENT OR ARRANGEMENT—An agreement under which one party (carrying party) agrees to pay for a specified portion or for all of the development and operating costs of another party (carried party) on a property in which both own a portion of the working interest. The carrying party may be able to recover a specified amount of costs from the carried party's share of the revenue from the production of petroleum, if any, from the property.

CARRIED PARTY—The party for whom funds are advanced in a carried interest arrangement.

CARRYING PARTY—The party advancing funds in a carrying interest arrangement.

CARVED-OUT INTEREST—A non-operating interest, often an overriding royalty (ORRI) sometimes a production payment, carved-out of a working interest. For example the owner of a 20 percent working interest (WI) with a 15 percent net revenue interest (NRI) may carve out and convey to a key employee an ORRI with one percent NRI leaving the WI owner with a 20 percent share of well costs and a 14 percent share of revenues.

CASH BALANCING—The method of paying cash, in lieu of delivering gas, to eliminate a gas imbalance. Terms for cash balancing may be set out in a separate gas balancing agreement or in the joint operating agreement.

CASING—Steel pipe placed in an oil or gas well as drilling and completion progresses. The function of casing is to prevent the wall of the hole from caving in during drilling and to facilitate safe oil and gas production if the well is productive.

CASINGHEAD GAS—A wet gas produced along with crude oil from oil wells. The *dissolved gas* or *solution gas* is dissolved in the reservoir's crude oil but bubbles out of the oil when exposed to normal atmospheric pressures. Casinghead refers to the top of the well's casing.

CASING POINT—When well *drilling* operations cease and the well owners must decide whether well *completion* should begin or the well plugged and abandoned. At casing point the well has been drilled to the objective depth and well logs, drill stem tests, and other tests of productivity are analyzed to judge whether probable production is sufficient to economically justify completion costs including the installation of production casing. A joint venture owner that is *carried to casing point* does not pay drilling costs, only completion costs. Casing point may also refer to the depth to which casing is set in a well.

CEMENTING—Pumping cement slurry down the well bore to fill the space created between the rock walls and the casing. Various types of cementing jobs include primary, secondary, squeeze, plug-back or multistage.

CENTRIFUGE—Machine in which samples of oil are placed and whirled at high speed to break out sediment.

CHECKERBOARD ACREAGE—Mineral interests situated in a checkerboard pattern.

GLOSSARY

CHRISTMAS TREE—A term applied to the well-head, i.e., the valves and fittings assembled at the top of a well to control the flow of production.

CLEAN-OUT COSTS—Costs incurred to clean out a well in order to maintain its productive capacity or to restore it to original capacity.

CLEARING ACCOUNTS—Accounts used to accumulate expenses during a period, with the balance allocated to other accounts on some predetermined basis at the end of the period.

COALBED METHANE—A high-methane natural gas adsorbed to underground coal and not substantially produced until the late 1980s when special federal income tax credits (IRC Section 29 tax credits) sparked a drilling boom.

COMPLETION—Refers to the work performed and the installation of permanent equipment for the production of oil or gas from a recently drilled well.

COMPRESSOR—Equipment on a gas pipeline to raise gas pressure to keep gas flowing.

CONDENSATE—A light hydrocarbon liquid, generally natural gasolines (C5 to C10), that condenses to a liquid (i.e., falls out of wet gas) as the wet gas is sent through a mechanical separator near the well.

CONNATE WATER—Water in the producing formation.

CONTIGUOUS LEASES—Leases which have a common boundary line.

CONTINUING INTEREST—Any interest in mineral property that lasts for the entire period of the lease contract with which it is associated.

CONVEYANCE—The assignment or transfer of mineral rights to another person.

COPAS—Council of Petroleum Accountants Societies.

COPAS EXHIBIT—The Operating Agreement's exhibit that establishes joint venture accounting practices using one of several standard forms developed by COPAS and found in various COPAS Accounting Bulletins.

CORE—A cylindrical sample of rock taken from a formation during drilling for purposes of determining the formation's permeability, porosity, hydrocarbon saturation, and other characteristics of petroleum productivity.

CORE ANALYSIS—A study of the core in a laboratory to determine the following properties of the formation from which the core was taken: porosity, permeability, fluid content, angle of dip, geological age, lithology, and probable productivity.

COST CEILING—The limit placed on the *carrying value* of oil and gas property in a cost center pursuant to FASB Standards or SEC Rule 4-10(i).

COST CENTER—The geological, geographical, or legal unit by which cost and revenues are identified and accumulated. Examples are the lease, the field, and the country.

CROSS-SECTION MAPPING—Maps of cross-section of underground formation.

CRUDE OIL—Liquid petroleum as it comes out of the ground, as distinguished from refined oils manufactured from it. Also called, simply, *crude*. Crude oil varies radically in its properties, viz, specific gravity and viscosity. Depending on the chemical nature of its chief constituents, crude oil is classified as paraffin base, asphaltic base, or mixed base.

CYCLING—A primary recovery method by which condensate is recovered from gas produced from a condensate gas reservoir, i.e., rich in condensate, and the residue gas is compressed and returned to the reservoir from which it was originally produced. The return of the residue gas serves to maintain the reservoir pressure so that the condensate remains in a gaseous state in the reservoir. If reservoir pressure dropped low enough for the condensate to liquefy in the reservoir, substantially less condensate could be recovered.

DAILY DRILLING REPORT—Twenty-four hour on-site report indicating all important events which occurred in drilling a well.

DAMAGE PAYMENTS—Payments made to the surface landowner by the oil or gas operator for damages to the surface, to growing crops, to streams, or to other assets of the landowner.

DAY RATE CONTRACT—An agreement between a drilling rig contractor and an operator wherein an agreed upon amount of money per day will be paid to the drilling contractor until a well is drilled to an agreed upon depth.

DEAD MAN—A buried anchor to which guy wires are tied to steady the derrick, boiler stacks, etc.

DECLINE CURVE—The plot of oil and/or gas production over length of time. Used to extrapolate the expected future production of a well as a basis for estimating proved reserves.

DEFERRED BONUS—A lease bonus payable in installments over a period of years. The deferred bonus is distinguishable from delay rentals because the deferred bonus payments are due even if the lease is dropped, whereas delay rentals are discontinued with the dropping of the lease.

DEHYDRATION—The process of removing water content from a gas stream to reduce the formation of hydrates (solid, crystalline compounds of water [90%] and hydrocarbons

[10%] that can disrupt natural gas movement). Usually performed at the wellsite(s) by use of a dehydrator which may treat commingled gas from several wells.

DELAY RENTAL—Amounts paid to the lessor (subsequent to the payment of any bonus) for the privilege of deferring the commencement of a well or the commencement of commercial production on the lease. Normally, rentals are paid prospectively on an annual basis.

DELINEATION WELL—A well to define, or delineate, the boundaries of the reservoir.

DELIVERY—The actual flow of gas or oil through a meter.

DELIVERY PRESSURE—The pressure of the gas from a well to be delivered into a pipeline. This is set out in the sales contract and stated in PSI.

DEPLETION—Amortization of capitalized costs of a mineral property. The deduction is based upon minerals produced. For federal income tax purposes, depletion may be based in part on the amount of gross income from the property.

DEPRECIATION—A tax deduction for tangible (equipment) costs whereby part of the purchase price is deducted every year until an amount equal to the cost of the item has been deducted.

DETAILED SURVEY—An intensive geological and geophysical exploration of an area of interest.

DEVELOPED PROPERTY—One on which wells have been drilled and production equipment has been installed

DEVELOPED RESERVES (or **DRILLED RESERVES)—**Crude oil or gas reserves which can be produced from existing facilities. (See definition of proved developed oil and gas reserves on App. 1-4.)

DEVELOPMENT COSTS—(See financial accounting definition starting on page App. 1-6.)

DEVELOPMENT WELL—A well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive. (See page 199 for an illustrative example.)

DEVIATED WELL—A well drilled at an angle from the vertical.

DIRECTIONAL DRILLING—Intentionally drilling a well at an angle from the vertical

DISCOVERY WELL—An exploratory well which discovers a new oil field.

DISPOSAL WELL—A well through which salt water is pumped to subsurface reservoirs to dispose of salt water produced with oil and gas.

DISSOLVED GAS—Natural gas mixed with crude oil in a producing formation.

DIVISION ORDER—A contract between all of the owners of an oil and gas property and the company purchasing production from the property. The contract sets forth the interest of each owner and serves as the basis on which the purchasing company pays each owner's respective share of the proceeds of the oil and gas purchased.

DOGHOUSE—A small house on the rig floor used for keeping records, storage, etc.

DOUBLE—Two lengths or joints of drill or other pipe joined together.

DRILLING PERMIT—A permit issued by a governmental body (usually a state) which gives permission to drill on a specified location to a specified depth, and which commits the operator to conform to all other requirements of the state regulations on drilling.

DRILLING RIG—The derrick, drawworks and attendant surface equipment of a drilling or workover unit.

DRY GAS—Natural gas composed of over 90 percent (some say 95 percent) methane and suitable for use by customers of local gas distribution companies.

DRY HOLE—An exploratory or development well that does not produce oil or gas in commercial quantities.

DRY HOLE CONTRIBUTIONS—Money or property paid by adjoining property owners to another operator drilling a well on property in which the payers have no property interest. Such contributions are payable only in the event the well reaches an agreed depth and is found to be dry. The payers may be entitled to proprietary information on the well.

DUAL COMPLETION—A well that simultaneously drains two reservoirs of oil or gas at different depths, with the production from each zone separated from the other by some type of tubing installation.

ECONOMIC INTEREST—An interest in mineral(s) in place which the owner has acquired by investment, and secures income derived from the extraction of the mineral(s) to which the owner must look for a return on capital.

EDQ—Equal daily quantities. An average daily volume used for pricing crude oil, by allocating volumes from multiple run tickets in a month.

EFFECTIVE DATE—The date a lease, acquisition or assignment is first in force. The balance sheet date for which a reserve estimate or ceiling test applies.

ENHANCED RECOVERY—Any method used to drive oil from reservoirs into a well in excess of that which may be produced through natural reservoir pressure, energy, or drive (primary recovery). (See SECONDARY and TERTIARY RECOVERY.) Pumping units that lift crude oil up the well are not enhanced recovery.

EXEMPT OWNER—An owner whose interest is exempt when calculating production, severance, or *ad valorem* taxes. Usually a government interest is exempt.

EXPLOITATION ENGINEERING—Engineering related to subsurface geology, the recovery of fluids from reservoirs, and the drilling and development of oil and gas reserves.

EXPLORATION COSTS—Costs incurred in identifying areas that may warrant examination, and in examining specific areas, including drilling exploratory wells and exploratory stratigraphic type test wells. (See App. 1-6 for the full financial accounting definition.)

EXPLORATION RIGHTS—Permission granted by landowners allowing others to enter upon their property for the purposes of conducting geological and geophysical surveys.

EXPLORATORY WELL—A well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be productive in another reservoir, or to extend a known reservoir. (See App. 1-5 for the full financial accounting definition.)

FARMOUT—Transfer of all or part of the operating rights from the working interest owner to an assignee, who assumes all or some of the burden of development, in return for an interest in the property. The assignor usually retains an overriding royalty but may retain any type of interest.

FASB—Financial Accounting Standards Board (discussed on page 58).

FAULTS—Oil and gas traps formed by the breaking and shearing of strata resulting from significant moving or shifting of the earth's surface.

FEE INTEREST—The ownership of both surface and mineral rights.

FERC—Federal Energy Regulatory Commission.

FIELD—An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geologic structural feature and/or stratigraphic feature.

FIELD EXPLORATORY WELL—A well drilled just outside the proved limits of a reservoir. Also known as a delineation well.

FIELD FACILITY—Oil and gas production equipment serving more than one lease, e.g., separator, extraction unit, etc.

FIELD PROCESSING—Treating oil or gas before it is delivered to a gas plant or refinery.

GLOSSARY

FIRE WALL—An earthen dike built around an oil tank to contain the petroleum if the tank ruptures.

FISH—Any object accidentally dropped or stuck in the wellbore during drilling, completion or workover operations. Operations to recover the object are called *fishing*.

FLARE—To burn unmarketable gas from a lease.

FLASH GAS—High BTU content gas which is vented from a low-pressure separator.

FLOW CHART— (1) a circular paper chart that records metered gas differential pressure and static pressure, used to determine gas volume flowing through the meter (see page 279) or (2) a schematic of how gas flows from point to point (see page 282).

FLOW LINES—Pipes carrying produced emulsion (oil, gas, or water) from wells to lease treatment and storage facilities.

FLOW TANK—The tank into which oil *is* stored after being produced.

FLOW TREATER—A piece of equipment which separates oil and gas, heats oil, and treats oil and water.

FLOWING WELL—A well which lifts oil and gas to the surface with natural reservoir pressure.

FLUID INJECTION—Inducing gas or liquids into a reservoir to move oil toward the well bore.

FLUSH PRODUCTION—The large flow of production initially made by a well immediately after being drilled.

FOOTAGE DRILLING CONTRACT—A well drilling contract which provides for payment at a specified price per foot for drilling to a certain depth.

FORCE MAJEURE CLAUSE—A lease or contract provision whereby the lessee is not in violation of the lease or contract in the event the lessee is incapable of fulfilling the lease or contract terms due to conditions or events beyond the lessee's control.

FORMATION—A bed or deposit composed substantially of the same minerals throughout.

FORMATION PRESSURE—Bottom hole pressure of a shut-in well.

FORMATION TESTING—The testing of a formation to determine its potential productivity before installing casing in a well.

FRACTURING—A procedure (*fracing* or *frac job*) to stimulate production by forcing under high pressure a mixture of fluid (usually diesel oil or water) and proppant (usually sand) into the formation. Fracing creates artificial fractures in the reservoir rock to increase permeability and porosity. The size of the frac job is expressed in terms of the pounds of proppant used (which might range from 20,000 to 1,000,000 pounds of sand).

FREE-WELL AGREEMENT—A form of sharing arrangement in which one party drills one or more wells completely free of costs to a second party in return for some type of economic interest in property.

FULL COST—The full cost method of accounting described in Reg. S-X Rule 4-10(c). A concept under which all costs incurred in searching for, acquiring, and developing oil and gas reserves are capitalized.

G&G (GEOLOGICAL AND GEOPHYSICAL) COSTS—Exploratory costs of surveys of a topographical, geological, and geophysical nature along with the costs incurred to obtain the rights to make these surveys, and salaries and other expenses of the personnel required to carry out the surveys.

GAS CAP—The free gas phase overlying an oil zone, occurring within the same producing formation as oil. (See **RESERVOIR**.)

GAS CHROMATOGRAPH—An analytical instrument that separates gases from each other. The gases are carried by a carrier, an inert gas that is usually nitrogen or helium, through a column filled with either a solid or liquid that is called the stationary phase or packing. This separates the gases into individual components depending on their affinity for the stationary phase. The more volatile, lighter, less polar compounds pass through the column fastest. A gas chromatograph is composed of (a) sample preparation, (b) sample valve, (c) column, (d) detector, and (e) signal recorder. The sample is introduced into the gas chromatograph with a syringe where it is immediately vaporized by heat. The separated compounds are identified by flame ionization or by a thermal conductivity detector and are recorded on gas chromatogram. Packed columns contain solid porous material that is coated with organic polymers, whereas the more common capillary columns have no solid support and the polymer coats the column walls.

GAS LIFT—Artificial means of extracting oil . Gas is injected down hole between casing and production tubing. The injected gas then aerates the liquid and *floats* up the tubing to the surface. Commonly used on off-shore wells.

GAS-OIL RATIO—A measure of the volume of gas produced along with oil from the same well.

GAS PAYMENT—A production payment payable out of gas produced.

GAS PLANT PRODUCTS—Natural gas liquids removed from natural gas in gas processing plants or in field facilities.

GLOSSARY

GAS SETTLEMENT STATEMENT—Statement provided to record the amount of gas transferred from well to pipeline. Statements generally include purchaser and seller identification, well identification, volume accepted, BTU content, pressure base, water content (i.e.. saturated or dry), and gross value due seller.

GAS WELL—A well producing primarily natural gas.

GATHERING SYSTEM—A group of small pipelines which moves the oil (or gas) from several wells into a major pipeline (or in the case of oil, a single tank battery).

GAUGE TICKET—A form on which the measurement of oil in lease tanks is recorded.

GAUGER—The individual responsible for the measurement of quantity and quality of oil and gas on a lease.

GBA—Gas Balancing Agreement.

GEOLOGICAL AND GEOPHYSICAL STUDIES—Processes which seek surface or subterranean indications of earth structure or formation of a type where experience has shown the possibility of mineral deposits exists.

GEOLOGICAL SURVEY—An exploratory program directed to examination of rock and sediments obtained by boring or drilling, or by inspection of surface outcroppings.

GEOPHYSICAL SURVEY—A study of the configuration of the earth's crust in a given area, as determined by the use of seismic, gravity, magnetic and geochemical procedures.

GEOPHYSICS—The study of the physics of the earth.

GPM—NGL gallons per one mcf of gas. Also an abbreviation for gallons per minute.

GRAVITY—A short for API gravity which expresses the density of a given petroleum fluid.

GRAVITY METER—An instrument measuring the variations in the gravitational pull.

GROSS WELLS—The total number of wells participated in, regardless of amount of interest. For example, a company owning a ten percent interest in each of 20 wells is said to have 20 gross wells and two net wells.

HOLE—The wellbore. Mouse hole and rat hole are shallow bores under the derrick in which the kelly joint and joints of pipe are temporarily suspended while making a connection.

HORIZON—An underground geological formation which is the portion of the larger formation which has sufficient porosity and permeability to constitute *a* reservoir

GLOSSARY

HORIZONTAL ASSIGNMENT—An assignment of an interest in the minerals above or below or between specified depths, or in a given stratum or horizon.

HORIZONTAL DRILLING—Deviation drilling that ultimately is horizontal or near horizontal to increase the length of the well bore penetrating the target formation as illustrated in Figure 8-6.

HYDROCARBON—An organic compound of hydrogen and carbon.

IDC (INTANGIBLE DRILLING COST)—A term used in income tax determination that refers to any cost which in itself has no salvage value and is necessary for and incident to the drilling of wells and getting them ready for production. IDC can also occur when deepening or plugging back a previously drilled oil or gas well, or an abandoned well, to a different formation.

IGNEOUS ROCK—Rock that is formed directly from the molten state.

IN SlTU COMBUSTION—The setting afire of some oil in the reservoir to create a burning front of gases which will drive oil ahead of it to the well bore.

INDEPENDENT PRODUCER—An oil company that engages in exploration, drilling and/or producing, but does not engage in transportation, refining or retail sales. Independent producers may process natural gas and market natural gas to gas consumers using third party pipelines to transport the gas. The original definition was one that applied to any company outside the Standard Oil Group.

INITIAL PRODUCTION—The figure given to a well indicating its capability to produce. May be the first full day's production, or a fraction thereof, multiplied to the equivalent of a day (*initial potential*). Abbreviated IP.

INJECTION OR INPUT WELLS—A well used to inject gas, water, or LPG under high pressure into a producing formation to maintain sufficient pressure to produce the recoverable reserves.

INSTALLMENT BONUS—See **DEFERRED BONUS**.

INTEGRATED OIL COMPANY—A petroleum company which engages in exploration, production and some significant refining, transportation, or retail operations in the petroleum industry.

INTERMEDIATE CASING STRING—The string of casing set in a well after the surface casing and before production casing. It serves to protect the well bore as the well is deepened and to seal off problem formations such as high pressure areas.

INTERRUPTIBLE GAS—Gas sold or transported without the pipeline's prior guarantee to move the gas.

IPAA—Independent Petroleum Association of America.

GLOSSARY

ISOPACH MAPS—Maps showing variations in the thickness of a particular sedimentary bed and the interval or spacing between one sedimentary bed and another.

JOINT—A single length of drill pipe, casing, etc., usually from 20 to 30 feet in length.

JOINT INTEREST OR JOINT VENTURE—An association of two or more persons or companies to drill, develop, and operate jointly owned property(ies). Each owner has an undivided interest in the property(ies).

JOINT OPERATING AGREEMENT—An agreement between two or more lease owners providing for the operation of a lease in which one operates the lease with all owners sharing in the cost.

KEEP-WHOLE AGREEMENT—A processing agreement where the producer receives 100 percent of the attributable residue gas and consideration for the attributable plant volume reduction (PVR). The payment for the PVR can be either equivalent BTU's of additional residue gas or a cash payment. The processor will generally keep 100 percent of the liquids extracted as payment for processing.

KELLY—The heavy square or hexagonal steel member which is suspended from the swivel through the rotary table and connected to the drill pipe to turn the drill string.

KILL A WELL—To stop formation fluids (usually under dangerous high pressure) from coming up a well. The stopping process uses mud (sometimes water) rather than closing well-head valves.

LACT UNIT (LEASE AUTOMATIC CUSTODY TRANSFER UNIT)—An automatic device for moving and measuring oil from lease storage to the pipeline. This requires a pump, an oil meter, and a BS&W measuring device.

LANDPERSON (OR LANDMAN)—A person employed by an E&P company responsible for identifying, negotiating, acquiring, retaining, or disposing of oil and gas leases and managing the company's land department. The term also refers to an independent broker for identifying, negotiating, and acquiring leases. The term Landman, whether referring to a male or female, continues to be more commonly used than the term Landperson.

LEASE—(1) A contract in which the owner of minerals gives an E&P company temporary and limited rights to explore for, develop, and produce minerals from the property. (2) Any transfer where the owner of a mineral interest assigns all or a part of the operating rights to another party but retains a continuing nonoperating interest in production from the property.

LEASE AND WELL EQUIPMENT—Capital investment in items of equipment having a potential salvage value and used in a well or on a lease. Such items include the cost of casing, tubing, well head assemblies, pumping units, lease tanks, treaters and separators.

GLOSSARY

LEASE CONDENSATE—See **CONDENSATE**.

LEASE OPERATING EXPENSES—The expenses, usually recurring, which pay for operating the wells and equipment on a producing lease.

LEASEHOLD INTEREST—Synonymous with working interest.

LEASE USE—Gas or natural gasoline used at the well site to operate production equipment.

LESSEE—A person entitled under an oil or gas lease to exploit the mineral deposits.

LESSOR—The owner of the mineral rights who has executed a lease.

LIFTING COSTS—Costs of operating wells for the production of oil and gas (producing costs).

LOCATION—The site for a well to be drilled or at which a well has been drilled.

LOGGING—The taking and recording of physical measurements about formations being drilled.

MAGNETIC METER—An instrument measuring the magnetic fields of the earth.

MAKE UP GAS—Gas taken in a later period that was paid for previously under a Take-or-Pay contract.

MAKING A TRIP—Consists of hoisting the drilling string out of and returning it into the wellbore.

MARGINAL WELL—A well whose production is so limited that it is marginally profitable to operate.

MASS SPECTROMETER—An instrument that is used to determine molecular weights and relative abundances of isotopes in a substance. The molecular components are ionized and disassociated by electronic bombardment. The positive ions are then accelerated in an electric field and separated magnetically by mass. A mass spectrometer is often used for gas analysis because it is fast and accurate. It can determine the amount of methane, ethane, propane, isobutane, N-butane, pentanes, hexanes, heptanes, and heavier hydrocarbons along with carbon dioxide, hydrogen sulfide, nitrogen, and helium content. The mass spectrometer can be used to calculate the Btu content of the gas.

MCF—The standard measure of volume for natural gas; i.e., 1,000 cubic feet.

METAMORPHIC ROCKS—Rocks developed as a result of sedimentary rocks subjected to heat and pressure.

GLOSSARY

MINERAL INTEREST—Economic interest in underground minerals (such as a **Mineral Right**, **Working Interest**, or **ORRI**).

MINERAL RIGHTS—Rights of ownership, conveyed by deed, of gas, oil, and other minerals beneath the surface.

MINIMUM ROYALTY—An obligation of a lessee to periodically pay the lessor a fee sum of money after production occurs, regardless of the amount of production. Such minimum royalty may or may not be chargeable against the royalty owner's share of future production.

MISCIBLE FLOOD—A tertiary recovery process similar to a water flood but involving the injection of a solvent that mixes with crude oil.

MMCF—The abbreviation for 1,000,000 cubic feet of gas; used to measure large quantities.

MOBILE DRILLING RIG—Either (1) a small land rig mounted on a truck (used for shallow wells) or (2) a drilling rig used offshore that can be floated from one drill site to another. Drill ships, jack-ups, and semi-submersibles are mobile rigs.

MOUSE HOLE—A hole drilled under the derrick floor and temporarily cased in which a length of drill pipe is temporarily suspended for later connection to the drill string.

MUD—Drilling fluid circulated through the drill pipe and back to the surface during rotary drilling and workovers.

MULTIPLE COMPLETION WELL—A well producing oil and/or gas from different zones at different depths in the same well bore with separate tubing strings for each zone. This is different from a commingled well which uses just one tubing string.

NATURAL GAS—Hydrocarbons that exist in the gaseous phase under certain atmospheric and temperature conditions.

NATURAL GAS LIQUIDS—Hydrocarbons (primarily ethane, propane, butane, and natural gasolines) which can be extracted from wet natural gas and become liquid under various combinations of increasing pressure and lower temperature.

NET-BACK PRICING—The method of pricing oil or gas by subtracting transportation costs (and sometimes processing and refining costs) from the downstream price received for the oil or gas.

NET-BACK SALE—The sale of produced wet natural gas for a price determined in part by proceeds from sale of extracted NGL.

NET PROFITS INTEREST—An interest in production created from the working interest and measured by a certain percentage of the net profits (as defined in the contract) from the operation of the property.

NET REVENUE—For the full cost ceiling, the proceeds of an oil or gas sale less the production and severance taxes, marketing and transportation cost, royalties and overriding royalties, and operating expenses.

NET WELLS—The aggregate of fractional interests an owner has in more than one well. (See **GROSS WELLS**.)

NEW FIELD WILDCAT—A well drilled in an area where previously there had been no production of oil or gas.

NOMINATION—The anticipated volume a producer expects to produce into a pipeline in the next month as communicated to the pipeline company for confirmation. Nominations are changed and confirmed as necessary.

NONASSOCIATED GAS—Natural gas (usually dry) not in contact with crude oil in a reservoir.

NONCONTINUING INTEREST—An interest in a mineral property whose life is limited in terms of dollars, units of product, or time.

NONOPERATING INTEREST—An interest in minerals for which the holder does not have the responsibility to bear the cost of developing and producing the minerals. Examples are royalties, overriding royalties, and volume production payments.

NONOPERATOR—An E&P joint venture participant that is not the operator managing the joint venture.

OFFSET WELL—(1) Well drilled on a well spacing unit adjacent to a producing well spacing unit. (2) Well drilled on a lease to minimize drainage of reserves by well(s) on an adjacent lease.

OIL POOL—An underground reservoir containing oil in the sedimentary rocks.

OIL SAND—Any porous reservoir containing oil, generally referring to a sandstone reservoir. The term *oil sands* may refer to formations close to the surface containing heavy hydrocarbons whereby the sands are mined and processed to produce synthetic crude oil. Oil sands mining is largely conducted in northeastern Alberta.

OIL SEEP—Areas where tiny amounts of petroleum have migrated to the surface.

OIL WELL—A well which can and does produce crude oil with minimal natural gas. Usually state regulations would classify a well as an oil well (as opposed to being a gas well) if it produced less than 15 mcf per barrel of oil.

OIL-WELL GAS—See **CASINGHEAD GAS**.

OPERATING AGREEMENT—An instrument defining the rights and obligations of the co-owners of the working interest of a lease in connection with the joint development and operation of the lease.

OPERATOR—An E&P joint venture participant that manages the joint venture, pays venture costs and bills the venture's non-operators for their share of venture costs.

ORIFICE METER—An instrument commonly used to measure the volume of flowing natural gas in a pipe.

OUTPOST WELL—A well drilled outside well locations offsetting a producing well but within the possible or probable extent of the reservoir. (See **STEP-OUT WELL**.)

OVERRIDING ROYALTY INTEREST (ORRI)—A royalty interest that is created out of the operating or working interest. Its term is coextensive with that of the operating interest from which it was created.

PAY—Oil or gas saturated rock capable of producing oil or gas.

PAYOUT—The condition at which the revenues to a given interest in a well equal all land, acquisition, drilling, completing and operating costs allocated to that interest.

PERCENTAGE DEPLETION—A deduction for Federal income tax purposes based on the gross income from mineral properties. Percentage depletion is in lieu of cost depletion. Also known as statutory depletion.

PERMEABILITY—The measure of the ease with which oil can move through a reservoir.

PETROLEUM—Oil or gas obtained from the rocks of the earth, usually by drilling down into a reservoir rock and producing them to the surface. (See Chapter One.)

PIG—A scraping instrument for cleaning a pipeline.

PLUG AND ABANDON—An expression, often abbreviated *P&A*, describing the act of placing plugs in a dry hole, then abandonment.

PLUG BACK—To seal off a lower formation in a well bore in order to produce from a higher formation.

POOL—An underground reservoir having a common accumulation of oil or gas.

POOLING—The joining of tracts to form a drilling unit.

POROSITY—The relative volume of the pore space compared to the total bulk volume of the reservoir.

POSTED FIELD PRICE—The published price that a crude oil purchaser will to pay for a specific grade of crude at the point that it is delivered by the seller and accepted by the purchaser on or after a stated date.

PRESSURE MAINTENANCE—Injection of gas, water, etc., to repressure an oil field.

PRESSURE REGULATOR—An instrument for maintaining pressure in a pipeline, downstream from the valve.

PRICE BULLETIN—A posting of the price per barrel the purchaser will pay for each grade of crude oil in a geographic area.

PRIMARY RECOVERY—Oil which is forced into the well bore by natural reservoir pressure, energy, or drive.

PRODUCTION PAYMENT—A production payment is an obligation of its grantor and a right of its holder for the grantor to pay the holder a specified portion of production proceeds or to deliver a specified portion of specified production before the production is expected to cease.

PRODUCTION STRING—The last and deepest string of casing set in a well through which oil or gas will be produced.

PRODUCTION TAXES—Taxes levied by state governments on mineral production based on the value and/or quantity of production. Also called severance taxes.

PRODUCTIVITY TEST—A test of the maximum or other rates at which a well can produce.

PROJECT AREA—A large territory that the taxpayer determines can be explored advantageously in a single integrated operation.

PROPERTY—For financial accounting, property refers to the aggregate economic interests owned through a lease or acquisition of a mineral interest. For income tax reporting, property refers to each separate interest owned by a taxpayer in each mineral deposit in each separate tract or parcel of land. Certain interests for tax purposes may be combined to form a property.

PRORATION—A system of allocating production from a well permitted to be produced during a period of time.

PROVED DEVELOPED RESERVES—Reserves which can be expected to be recovered through existing wells with existing equipment and operating methods. (See full definition on App. 1-4.)

PROVED RESERVES—Quantities of reserves that, based on geologic and engineering data, appear with reasonable certainty to be recoverable in the future from known oil and gas reserves under existing economic and operating conditions. (See full definition on App. 1-3 and 1-4.)

PROVED UNDEVELOPED RESERVES—Reserves which are expect- ed to be recovered from new well(s) on undrilled proved acreage, or from existing wells where a relatively major expenditure is required for completion. (See full definition on App. 1-4 and 1-5.)

PROVEN PROPERTIES—For federal income tax purposes, a property whose principal value has been demonstrated by exploration, discovery, or development. For financial accounting purposes, a property containing proved reserves.

PUMPER—The individual responsible for all equipment contained on the lease.

QUARTER SECTION—A one fourth section of land. Measures 1/2 mile on a side and equals 160 acres (a full section being 640 acres, one mile wide).

RABBIT—Line cleaning instrument. A small plug which is run through a line.

RAT HOLE—A hole from 30 to 35 feet deep, with casing that projects above the derrick floor, into which the kelly is placed when hoisting operations are in progress.

RECOMPLETION—As defined in the AAPL model form operating agreement, App. 9-6, recompletion is "an operation whereby a completion in one zone is abandoned in order to attempt a completion in a different zone within the existing wellbore." (See **WORKOVER**.)

RESERVOIR—A porous and permeable underground formation containing a natural accumulation of producible oil or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

RESIDUE GAS—The gas produced at the tail gate of a gas processing plant after all natural gas liquids and natural gas liquid products have been removed.

RETAINED INTEREST—The interest kept by the grantor when selling or assigning interest to another.

REVERSIONARY INTEREST—A portion of an economic interest that will be returned to its former owner after a predetermined amount of production or income has been produced.

ROYALTY or ROYALTY INTEREST—The land owner's (lessor's) share of oil or gas production (typically 1/8, 1/6, or 1/4) free of cost, but subject to severance taxes unless the lessor is a government.

RUN TICKET—A record of the quantity of oil removed out of a stock tank into a pipeline or tank truck. A run ticket will generally have opening and closing volumes, observed gravity and temperature, BS&W, and date and time of delivery. It is usually made in triplicate and filled out by the gauger employed by the purchaser and sometimes witnessed by the pumper as subcontractor or employee of the E&P company operating the well.

SECONDARY RECOVERY—Now refers to water flooding. Used to refer to any process of injecting water, gas, etc., into a formation to build up pressure in order to produce additional oil otherwise unobtainable by primary recovery.

SECONDARY RESERVES—Reserves recoverable by secondary recovery.

SEISMIC—An exploration method of sending energy waves or sound waves into the earth and recording the wave reflections to indicate the type, size, shape, and depth of subsurface rock formations. 2D seismic gives two dimensional information. 3D seismic provides three dimensional pictures. 4D seismic provides 3D pictures over time, used to indicate fluid movement in producing reservoirs.

SEISMOGRAPH—A device for detecting vibrations in the earth. It is used in prospecting for probable oil-bearing structures.

SEPARATOR—A cylindrical or spherical device located at the well site to separate commingled oil and gas through gravity and centrifugal force. The oil will drop out and the gas will rise and escape through separate outlets.

SHOOTING—Shooting seismic. Exploding nitroglycerin or other high explosives in a hole to shatter the rock and increase the flow of oil.
SHUT-IN WELL—A well which is capable of producing oil or gas but which is not on production.

SLIM HOLE—A small diameter well, generally drilled to achieve less expensive exploration or limited development. A slim hole development well cannot generally be recompleted and cannot be as easily repaired as a normal diameter well. Should a producing slim hole well have behind-pipe reserves, a second well normally must be drilled to produce such reserves.

SMOG—A FAS 69 disclosure called the standardized measure of discounted future net cash flows relating to proved oil and gas reserves. (See Chapter Twenty-Nine.)

SOUR OIL or **SOUR GAS—**Oil or gas with a high sulfur content.

SPACING—The regulation of the number of wells which can be drilled on a given area of land. Depending on the depth of the reservoir, this may be one well on 5 to 640 acres. Typical spacing is 40 acres for oil wells and 640 acres for gas wells. However, spacing for tight sands gas production may be 20 acres.

SPLIT CONNECTION—One gas well being connected to more than one pipeline. This is caused by two or more working interest owners selling to different pipelines.

SPUD—To commence actual drilling operations.

STEP-OUT WELL—A well drilled outside well locations offsetting a producing well but within the possible or probable extent of the reservoir. (See **OUTPOST WELL**.)

STIMULATION—A mechanical process (such as *fracing*) or a chemical process (such as *acidizing*) to change the characteristics of the reservoir portion near a well to increase well production. (See **ACIDIZE, FRACTURING**, and **WORKOVER**.)

STRATIGRAPHIC TEST WELL—A well drilled to obtain information about geologic conditions. (See financial accounting definition on App. 1-5.)

STRIP A WELL—To pull both the rods and tubing from a well simultaneously.

STRIPPER WELL—A well with marginally economic production. For income tax percentage depletion on marginal production after 1990, a stripper well is one on a property that produces a daily average of 15 boe or less of oil or gas per producing well for the calendar year in which the taxpayer's tax year begins. Traditionally, a stripper well had an average production of ten barrels of oil or 60 mcf of gas per day. Considering that the average U.S. oil well produced ten barrels of oil per day in 1999 (Figure 2-2), a large number of U.S. oil wells may be called stripper wells.

STRUCTURAL MAPS—Maps that indicate the contours of the subsurface.

SUCCESSFUL EFFORTS ACCOUNTING METHOD—A financial reporting accounting method under which costs incurred in searching for, acquiring, and developing oil and gas reserves should be capitalized if they result directly in acquiring, finding, or developing proved reserves. All other costs are expensed as incurred.

SWAB—A device that fits tightly inside the tubing; when pulled through the tubing, it lifts fluid.

SWEET OIL or **SWEET GAS**—Oil or gas containing a relatively small amount of sulfur.

TAKE-OR-PAY CONTRACT—An agreement in which the purchaser of gas agrees to take a minimum quantity of gas per year if he is not prevented from doing so by circumstances beyond his control and if the gas is available for delivery to him. If the purchaser does not take the minimum quantity, he is required to pay for that minimum quantity at the contract price; normally, he may make up deficiency amounts in future years if he purchases in excess of minimum amounts. New take-or-pay contracts became rare in the 1990s, after gas purchasers suffered substantial losses in older contracts when gas prices unexpectedly declined.

TANGIBLE COSTS—The cost of assets that in themselves have a salvage value.

TANK BATTERY—A group of storage tanks to which crude oil flows from producing oil wells.

GLOSSARY

TANK STRAPPER—The individual who measures a tank and prepares a tank table.

TANK TABLE—A table showing the volume of a tank at various levels based on one-fourth-inch intervals.

TD—Abbreviation for *total depth,* the bottom of the well.

TEMPORARILY ABANDONED WELL—A well, which is deemed nonproductive, but which is not permanently plugged as there is intent to use it for some other purpose or to reestablish production if economics improve.

TERTIARY RECOVERY—The use of sophisticated techniques such as flooding the reservoir with steam to increase the production of oil or gas.

THIEF—A device for extracting oil samples from a tank.

TIGHT HOLE—A drilling or completed well on which the operator refuses to release information.

TOP LEASES—The granting of a new oil or gas lease prior to the termination of an existing lease, the new lease becoming effective upon expiration of the old lease.

TRUNCATION TRAPS—Traps associated with unconformities or discontinuities in the strata.

TUBING—Small diameter pipe suspended in a well through which gas or oil is produced.

TURNKEY WELL—A completed, producing well, drilled and equipped by a contractor for a fixed price.

UNDEVELOPED PROPERTY—One which has not been drilled or equipped for production.

UNITIZATION—An agreement under which two or more persons owning operating mineral properties agree to have the properties operated on a unified basis and further agree to share in production from all the unitized properties on a stipulated percentage or fractional basis regardless of which property the oil or gas is produced from. All owners of economic interests in the properties should be involved in the agreement.

UNIT-OF-PRODUCTION METHOD—A method of computing depreciation or depletion provisions based on quantities produced in relation to reserves. (See Chapters Seventeen and Nineteen for examples and formulas of the Unit-of-Production Method.)

VALVE—A device used to control the rate of flow in a line, to open or shut off a line completely, or to serve as an automatic or semiautomatic safety device.

VISCOSITY—The ability of a fluid to flow as a result of its physical characteristics.

WATER WELL—A well drilled to obtain a supply of water for drilling or operating use.

WATERFLOODING—The secondary recovery method in which water is forced down injection wells laid out in various patterns around the producing wells. The water injected displaces the oil and forces it to the producing wells.

WELL—A hole drilled in the ground to obtain geological information, find and produce oil or gas, or provide service to the operation of an oil or gas property.

WELLHEAD—The equipment used to maintain surface control of a well.

WET GAS—Gas that contains a large quantity of liquids.

WILDCAT—An exploratory well that is particularly risky, e.g., not having seismic data or nearby producing fields to support the prospect.

WORKING INTEREST—The interest in the oil and gas in place which is burdened with the cost of development and operation of the property. Also called the operating interest.

WORKOVER—A major remedial operation on a completed well to restore, maintain, or improve the well's production. Workovers use *workover rigs* and can take many forms such as *acidizing* or *fracing* the well or removal of sand or paraffin buildup. Workover costs to restore or maintain production are expensed as incurred. The term workover is also used for deepening an existing well or plugging back to produce from a shallower formation. Costs to explore to an unproved formation are exploration costs. Costs to access a proved formation are development costs. The term workover excludes minor repairs or well servicing such as repair or replacement of downhole equipment.

ZONE—A stratigraphic interval containing one or more reservoirs.

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