MSSP

Market Segment Specialization Program

# Oil and Gas Industry

The taxpayer names and addresses shown in this publication are hypothetical. They were chosen at random from a list of names of American colleges and universities as shown in Webster's Dictionary or from a list of names of counties in the United States as listed in the United States Government Printing Office Style Manual.

This material was designed specifically for training purposes only. Under no circumstances should the contents be used or cited as authority for setting or sustaining a technical position.

Department of the Treasury
Internal Revenue Service

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**Technical References**

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## INDEX TO EXHIBITS

| No. | Title | Explanation |
|---|---|---|
| 1-1 | Oil and Gas Lease and Mineral Deed | Petroleum companies obtain the rights to explore, drill, and produce subsurface minerals by entering into an oil and gas agreement or "lease" with the landowner. An oil and gas lease embodies the legal rights, privileges and duties pertaining to the lessor and lessee. The lessor is the mineral interest owner who transfers the working interest to the lessee who retains a royalty interest. The mineral lease is a very important legal document to the petroleum industry and provides the framework for all the activities that follow. It can be a useful auditing tool, because it provides a description of the property, identifies the royalty owner, and can give details of such items as delay rentals, lease bonus, unitizations, and primary terms. |
| 1-2 | Accounting Procedure Accompanying a Joint Operating Agreement | When a joint interest situation is created, the parties involved (i.e., the operator and nonoperators) generally execute an operating agreement. The normal form used for the operating agreement is AAPL Form 601. The joint operating agreement delineates the responsibilities and duties of the operator and nonoperators. It may cover only drilling operations, or it may cover both, exploration and production. |
| 1-3 | Division Order | Prior to the sale of oil or gas covered by a particular lease, a division order is prepared and signed by all interest owners. The division order is a necessary instrument in order for the operator to orderly and legally collect the oil and gas revenues and to pay the correct owners of the minerals. |
| 1-4 | Division of Interest | For accounting purposes, the information on the division order is usually condensed into a more usable format that can be put into the lease file for easy reference. Such a "division of interest" will be prepared for each property and shows each owner's name, identification number, and fractional interest. |
| 2-1 | Example of Tax Benefit for IDC with AMT | This exhibit shows the effect of the application of the tax benefit rule when computing the tax preference item for IDC when one has both the IDC preference and the depletion preference. |
| 3-1 | Texas Railroad Commission Forms | This exhibit provides explanations for various forms available from the Texas Railroad Commission. |

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# FOREWORD

The purpose of this Market Segment Specialization Program (MSSP) audit techniques guide is to provide examiners reference material relating to the oil and gas industry for General Program examinations. This guide is a compilation of various sources offering a quick reference guide to examiners. Its intent is to supplement the oil and gas training material published and taught in formal training. Reference is not made to all of the facets or issues of the oil and gas industry. However, this guide will enable one to become familiar with the basic operations and common terminology of the oil and gas industry, including brief references to royalty owners. Examiners are still encouraged to continue to use the specialized audit techniques handbook (IRM 4232.8, Techniques Handbook for Specialized Industries -- Oil and Gas) and consult petroleum engineers when necessary, as well as other outside reference material written on the oil and gas industry.

The Midstates Regional office "houses" the Petroleum Industry Program (PIP) which has specialists in the oil and gas industry. These specialists are "geared" mainly towards issues that affect CEP examinations. However, if an examiner identifies a complex issue in a General Program case and needs assistance, PIP could be consulted.

It has become common knowledge that the oil and gas industry has expanded their activities into financial products. This guide will introduce you to the vehicles that are being used to "hedge" and claim an ordinary loss versus a capital loss. The revised specialized audit techniques handbook mentioned above should be consulted for further guidance in this area.

Reference materials used in preparing this guide include the following:

1. Internal Revenue Code of 1986.

2. Income Tax Regulations.

3. *Oil and Gas Taxation*, by John P. Klingstedt, Horace R. Brock, and Richard S. Mark.

4. *Income Taxation of Natural Resources 1992*, by C.W. Russell, C.P.A.

5. Internal Revenue Manual 4232.8, Techniques Handbook for Specialized Industries - Oil and Gas.

6. Publication 641, Service 1 Basic Volume 1953-1990, Bulletin Index-Digest System, Volumes I and II.

7. Oil and Gas Units I and II, Texts (courses 3185 and 3186).

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# Chapter 1

# OIL AND GAS INDUSTRY

## OVERVIEW

The oil and gas industry has been in an economic slump since the mid-1980's. There have not been significant domestic explorations that have been successful. In 1992, a manufacturer of equipment related to drilling of oil and gas wells said it was closing its doors because the life of its product was 20 years and a new order had not been received domestically for 10 years. Also, there have been newspaper articles in the past 3 years expressing concerns from companies based in Oklahoma over the drop in the price of natural gas. However, this concern has been alleviated somewhat as the price of natural gas has steadily increased since then, to a new 5-year high in March 1993. In March 1994, an article in the *Dallas Morning News* provided some statistics that depicted an industry in distress. It stated the following:

1. Oil and gas industry employment in the United States slipped to 1.43 million last year, the lowest in more than 20 years.

2. U.S. oil production fell to 6.8 million barrels per day in 1993, the lowest since 1958.

3. U.S. oil imports continue to rise reaching 6.7 million barrels per day last year.

The Service expended extensive time and resources auditing the oil and gas industry and related businesses in the 1970's and early 1980's. With the passage of the Crude Oil Windfall Profit Tax Act of 1980, the Service expanded its resources to include the examination of this excise tax in conjunction with the income tax considerations of the oil and gas industry.

Since the mid-1970's, there have been regulations, legislation, and judicial decisions that have narrowed the gap with regard to differences of opinions in the interpretations of various sections of the law. The various interpretations related to Congress' intent as to how this particular area of law is to be applied.

What does the future hold for oil and gas? It appears that the basic oil and gas issues exist. There is no new wrinkle in the industry such as we saw in tax shelters involving computers, real estate, etc. However, there does appear to be an area that has good potential for auditing. Due to the declining oil and gas prices, there has been increased activity by natural resource companies in the financial markets, trading on the exchange and off exchange. Examiners should be cognizant of financial product transactions when examining oil and gas companies.

## GENERAL DESCRIPTION OF THE INDUSTRY

### Mineral Interests

To determine the proper tax treatment of oil and gas transactions, one needs to have a basic understanding of the various mineral interests. An operator may acquire the mineral rights in two ways. The first, and most common, method is to acquire the right to the minerals through a mineral lease. The other way is to acquire the mineral interest in fee.

### Acquisition Through Mineral Lease

The interest begins with the landowner. The landowner owns the land in fee, including the minerals on and below the surface, but does not possess the financial resources or technology required to drill a well. If the landowner does not want to sell the mineral rights outright, he or she can convey the rights to develop the minerals through a lease. (See Exhibit 1-1 for an example of a mineral lease.) The landowner typically leases the mineral interest and retains a royalty interest, usually between a one-eighth and three-eighths interest. After leasing the property and retaining a royalty interest, the landowner takes on a new posture in the field of oil and gas; he or she becomes a "fee royalty owner," as well as the landowner. It should be noted that the owner of the land in fee can dispose of all or part of the mineral rights and sell them to a third party. The third party which purchases the mineral rights would become a "mineral owner" without being a landowner. The landowner will have very few expenses associated with the mineral interest. If the property is producing, the landowner will have severance or production taxes, depletion, and, possibly, a small amount of overhead.

The royalty owner generally receives one-eighth of all the oil and gas produced from the lease as a result of retaining a royalty interest of the same percentage in this type of transaction. A royalty interest entitles its owner to share in the production from the mineral deposits, free of development and operating costs and extends over the productive life of the property leased. The lessee in the transaction usually acquires the balance of the mineral rights, less the percentage retained by the royalty owner, in the form of a working interest. A working interest not only entitles its owner to share in the production, but also requires the owner to bear their share of the developing and operating costs.

The working interest owner may not have the working capital necessary to drill the well or may want to share the risk. One may, subject to certain restrictions, sell or dispose of all or part of the working interest in the total production and in the process create additional subdivisions of it such as an overriding royalty interest, production payments, net profits interest, etc. If some of the working interest is sold to other investors, a joint venture is created. (See Exhibit 1-2 for an example of the Accounting Procedure accompanying a Joint Operating Agreement.) The venture may be a formal partnership with a return being filed, or it may elect out of the partnership filing requirements. It is not unusual for a lessee to be involved in working interests and have an overriding royalty interest in working interests.

A royalty interest can be acquired by purchase from the landowner, who may sell an entire interest or any fraction thereof. This usually occurs after a lease has been granted for the development of the property and there appears to be a prospect of future production. The purchase is usually made by an investor or royalty dealer.

As the taxpayer branches out from developing and operating the mineral interest to refining and retailing the minerals extracted, the return becomes more complex. A determination of whether the taxpayer is an independent producer or integrated oil company must be made; as the tax treatment is quite different for each. An independent producer, as defined by IRC section 613A(d), is a producer who does not have more than $5 million in retail sales of oil and gas in a year or one who does not refine more than 50,000 barrels of crude oil on any day during the year. A qualified independent producer will be denied a percentage depletion deduction on production volumes which exceed the average daily production of 1,000 barrels of crude oil. An integrated oil company is a producer which is also either a retailer, which sells more than $5 million of oil or gas in a year, or a refiner, which refines more than 50,000 barrels of oil on, any day during the year. However, it should be noted that the classification of an independent producer can be denied, even when the producer does not own a refinery, when an associated company refines more than 50,000 barrels in any day of the year. This is especially true when some of the producer's oil or gas is traced to the associated company's refinery, even through an exchange with a third party.

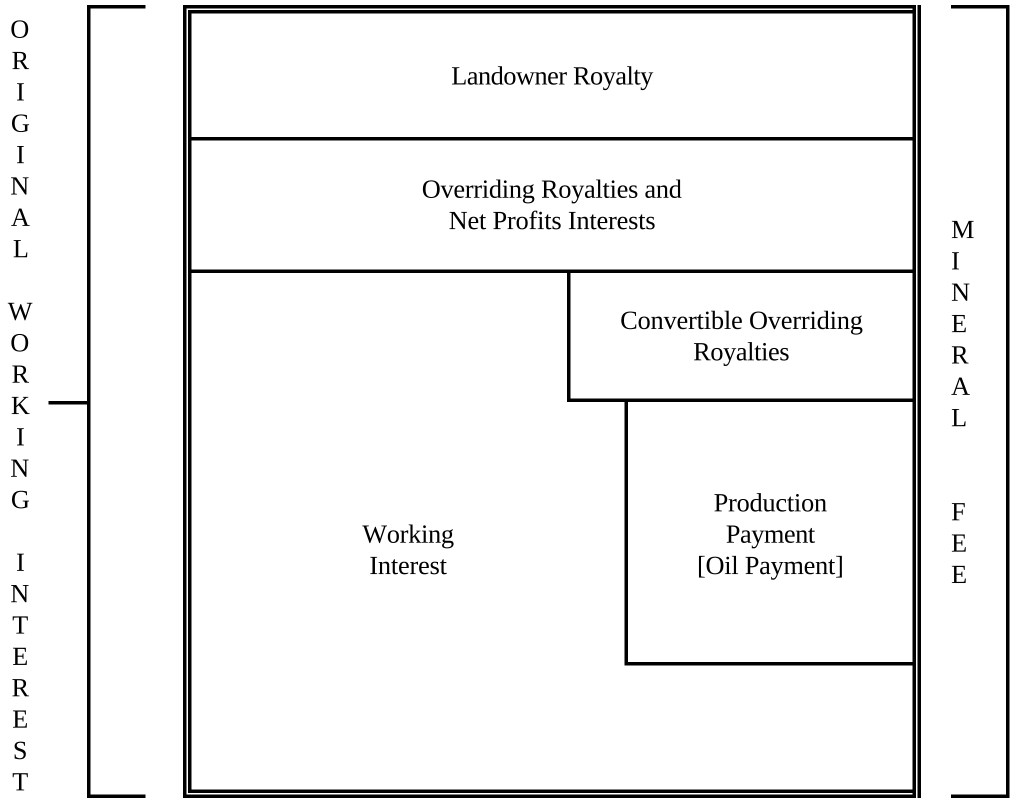
## **Acquisition in Fee**

When the operator acquires the mineral rights in fee, the operator will have the right to 100 percent of the income generated from the production. Also, 100 percent of the cost to drill and complete the wells on the property will be incurred. Such an interest is described as an 8/8s mineral interest or "working interest."

The cost incurred to purchase the fee mineral interest should be capitalized and recovered through depletion. If the mineral owner drills a well, the intangible drilling costs (IDC) should be capitalized or deducted depending upon the taxpayer's election. Tangible costs should be capitalized and recovered through depreciation. Expenses incurred to operate the property would be an allowable ordinary and necessary business expense deduction.

### **Figure 1-1**

Below is an illustration of the various oil and gas property interests.


ORIGINAL WORKING INTEREST
Landowner Royalty
Overriding Royalties and
Net Profits Interests
Convertible Overriding
Royalties
Production
Payment
[Oil Payment]
Working
Interest
MINERAL FEE

The following, Scenarios A through E, illustrates how one property containing minerals can be carved up into various mineral interests.

Scenario A

Owner A holds the fee interest in minerals. A also owns all of the rights in perpetuity.

| |
|---|
| FEE OWNER A —<br>100 PERCENT INTEREST |

Scenario B

Owner A leases the mineral rights to B (the lessee), retaining a 1/5 (20 percent) basic (landowner's) royalty. The lease contract is for a primary term and as long thereafter as oil or gas is produced. A (the lessor) will receive 20 percent of all production proceeds and B will receive 80 percent (4/5) of production proceeds. If the primary term expires, or if oil or gas subsequently ceases, the lease expires and all rights revert to A, the mineral rights owner.

| INTEREST BEFORE SCENARIO B | INTEREST AFTER SCENARIO B |
|---|---|
| FEE OWNER A —<br>100 PERCENT INTEREST | A — 20 PERCENT FEE OWNER'S ROYALTY |
| | B — 80 PERCENT WORKING INTEREST |

Scenario C

B subleases the property to C, retaining a 1/10 (10 percent) overriding royalty (ORRI). The ORRI lasts only as long as the original lease contract between A and B is in force. Now A is entitled to 20 percent of the production, B is entitled to 10 percent, and C (the new working interest owner) is entitled to 70 percent.

| INTEREST BEFORE SCENARIO C |
|---|
| A — 20 PERCENT FEE OWNER'S ROYALTY |
| B — 80 PERCENT WORKING INTEREST |

| INTEREST AFTER SCENARIO C |
|---|
| A — 20 PERCENT FEE OWNER'S ROYALTY |
| B — 10 PERCENT (ORRI) |
| C — 70 PERCENT WORKING INTEREST |

## Scenario D

C carves out and sells to D a "production payment" that entitles D to receive 500,000 MCF of gas, payable out of 60 percent of the net working interests share of gas each month (60 percent of 70 percent = 42 percent of the total mineral interest). When the production payment has been satisfied, D will have no further interest in the minerals. C will receive 28 percent (40 percent of 70 percent) of production until the production payment is paid out. After the pay out is completed, C then will begin to receive 70 percent of the remainder of the productive life of the property.

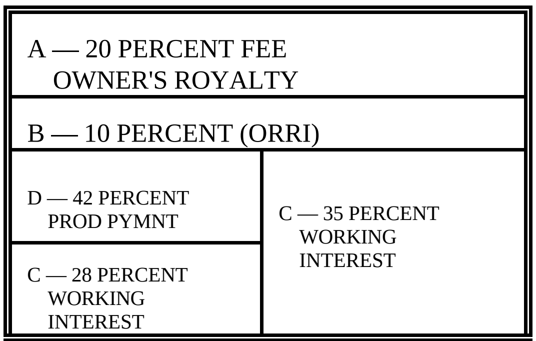
| INTEREST BEFORE SCENARIO D |
|---|
| A — 20 PERCENT FEE OWNER'S ROYALTY |
| B — 10 PERCENT (ORRI) |
| C — 70 PERCENT WORKING INTEREST |

<table>
<tr><th colspan="2">INTEREST AFTER SCENARIO D</th></tr>
<tr><td colspan="2">A — 20 PERCENT FEE OWNER'S ROYALTY</td></tr>
<tr><td colspan="2">B — 10 PERCENT (ORRI)</td></tr>
<tr><td>D — 42 PERCENT PROD PYMNT</td><td rowspan="2">C — 70 PERCENT WORKING INTEREST</td></tr>
<tr><td>C — 28 PERCENT WORKING INTEREST</td></tr>
</table>

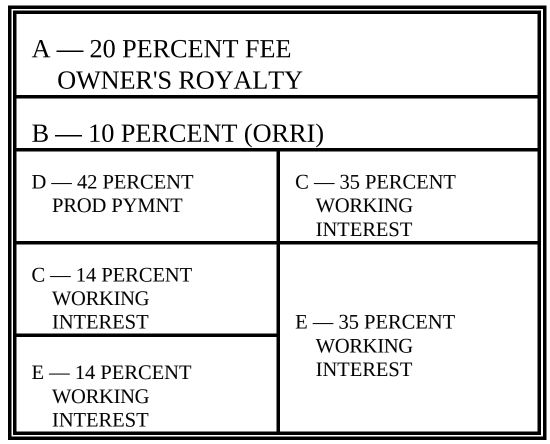
Scenario E

C sells one-half (50 percent) of the net working interest to E. C and E (now owners of undivided interests in the working interest) each will receive 14 percent (50 percent × 40 percent × 70 percent) of the production until the production payment to D is satisfied. After pay out of the production payment to D, C, and E will receive 35 percent (50 percent × 70 percent of the working interest) of production.

INTEREST BEFORE
SCENARIO E




INTEREST AFTER
SCENARIO E




## **Property Overview**

The mineral interests concept and knowing who the various parties are and their titles in the world of oil and gas are vital information to know when being introduced to oil and gas. Next one must become familiar with the "property concept." This concept is the basis for the use of the property unit as the tax entity for purposes of depletion, abandonment losses, recapture rules, etc. The property definition set forth in IRC section 614 emphasizes separateness, specifically, the separateness of different types of interests, geographic locations (surface), and oil and gas deposits (subsurface). IRC section 614(a) defines the term property to mean "*** each separate interest owned by the taxpayer in each mineral deposit in each separate tract or parcel of land."

The taxpayer might manipulate the definition of property to attempt to take larger deductions for depletion, to take a premature deduction for an abandonment, or to reduce its recapture potential. Many taxpayers will account for their income and expenses on a well-by-well basis for their accounting records. Others might segregate their income and expenses by prospect. Since their records are set up this way, they may not want to go through the inconvenience and cost to convert the records to reflect the property concept for tax purposes.

## TYPES OF OWNERSHIP INTEREST

Each different type of interest is treated as a separate property. For example, if a taxpayer owns a royalty interest and a working interest in the same tract of land, the taxpayer would have two separate tax properties. This position is set out in Rev. Rul. 77-176, 1977-1 C.B. 77.

### Tract or Parcel

A single lease may cover a number of separate tracts or parcels of land. The fact that several tracts are covered by a single lease does not mean that they are automatically one property. The deciding factor that determines whether or not two or more tracts of land will be considered one property is whether the tracts are contiguous or have a common side. Each separate tract refers to the physical area which is delineated by the legal description. Tracts which touch at a corner are adjacent, not contiguous, and would be treated as separate properties. All contiguous tracts or parcels of land obtained on the same day from the same person must be treated as one property in accordance with Treas. Reg. section 1.614-1(a)(3).

### Separate Deposits

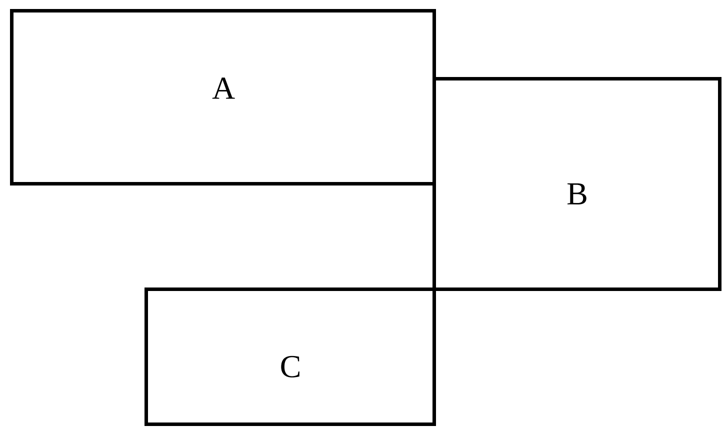
IRC section 614(a) states the general rule that each separate mineral deposit on each tract will be treated as a separate property. However, IRC section 614(b)(1) and (2) provide a special rule which allows operating mineral interests in oil and gas deposits in a tract or parcel to be treated as one property, unless an election is made to treat the deposits separately. When an election is made to treat the deposits as separate properties, production from the deposits must be accounted for separately.

### Unitization

To develop a reservoir more effectively, a number of different property owners may combine their properties into a single unit. Some states require unitization within each field or reservoir. Whether or not the unitization is voluntary or involuntary, the effect is the same. Several separate properties are combined within a unitization agreement. Thus, one property is created for the taxpayers.

Figure 1-2 below illustrates the difference between adjacent and contiguous areas.

**Figure 1-2**




1. A and B are contiguous properties, treated as one property, because they have a common side.

2. B and C are adjacent properties, treated as separate properties, because they only touch at a corner. They do not have a common side.

## ACCOUNTING METHODS

When auditing a taxpayer in the oil and gas industry, it is important to determine the method of accounting used for book and tax purposes. An individual landowner/lessor usually uses the cash method of accounting for income and expenses. The working interest owner/lessee will use either the cash or accrual method. In conjunction with either method, the taxpayer may also use the successful efforts (SE) method or the full cost (FC) method of accounting for financial statement purposes. Both methods, FC and SE, were developed by the oil and gas industry to account for its operations for financial purposes. Although neither method is used for tax purposes, it is important to understand the method the taxpayer uses for financial record keeping. This knowledge will help to understand the adjusting entries made at year-end to convert the books to income tax reporting and determine whether they are properly handled.

### Successful Efforts (SE) Method

The Financial Accounting Standards Board (FASB) has issued FASB Statement No. 19 dealing with the successful efforts method. Under the SE method, costs incurred in searching for, acquiring, and developing oil and gas reserves are capitalized if they directly result in producing reserves. Costs which are attributable to activities that do not result in finding, acquiring, or developing specific reserves are charged to expense. The cost center for the SE method is a lease, field, or reservoir.

The various types of costs are treated under the SE method as follows:

1. Acquisition Costs: They are capitalized to unproven property until proved reserves are found or until the property is abandoned or impaired (a partial abandonment). If adequate reserves are discovered, the property is reclassified from unproven property to proven property. For tax purposes, acquisition costs are handled the same way except the cost cannot be partially written off as an impairment expense. The property must be abandoned before any cost may be written off.

2. Exploration Costs: They are recorded in two different ways, depending upon the type of costs incurred.

    a. Nondrilling Costs: Examples of these type of costs are geological and geophysical (G & G) costs, costs of carrying and retaining undeveloped properties, and dry hole and bottom hole contributions. These types of costs are expensed as they are incurred. For tax purposes, nondrilling costs are capitalized to the applicable property.

    b. Drilling Costs: They are treated differently depending on whether the well drilled is classified as an exploratory well or a developmental well. An exploratory well is a well drilled in an unproven area. A developmental well is a well drilled to produce from a proven reservoir.

        1) If an exploratory well is a dry hole, the costs incurred in drilling the well are expensed. If the exploratory well is successful, the costs incurred in drilling the well are capitalized to wells and related equipment and facilities.

        2) The costs incurred in drilling developmental wells are capitalized to related equipment and facilities even if a dry hole is drilled.

    For tax purposes, there is no distinction made between exploratory and developmental wells. Intangible drilling costs (IDC) for either type of well are capitalized unless an election is made to expense them in accordance with IRC section 263(c). It should be noted that only domestic IDC can be expensed. Foreign IDC is capitalized and amortized over a 10-year period. Integrated oil companies which elect to expense domestic IDC may only expense 70 percent of the IDC incurred. The remaining domestic IDC, 30 percent, must be capitalized and amortized over a 5-year period. Dry hole costs for either type of well may be expensed unless the taxpayer capitalizes IDC. If the taxpayer capitalizes IDC, then an election is required to expense dry hole costs in accordance with Treas. Reg. section 1.612-4(b)(4). Thus, an M-1 adjustment would be required for all IDC incurred unless the IDC is incurred on an exploratory dry hole.

    The costs associated with tangible well equipment and facilities are capitalized, regardless of the type of well drilled. For tax purposes, certain costs associated with such equipment are eligible for treatment as deductible IDC. Tax depreciation methods usually allow for a more accelerated rate of depreciation than book or financial depreciation. Also, book depreciation will be computed on the developmental dry holes and IDC which are capitalized for book purposes but expensed for tax purposes. Therefore, an M-1 adjustment will be required on the difference between the amount of book and tax depreciation.

3. Production Costs: These costs are expensed as incurred, which is the same treatment used for tax purposes. It should be noted, however, that many taxpayers erroneously expense overhead attributable to either acquisition or exploration activities as production costs. Overhead attributable to acquisition and exploration costs must be capitalized.

4. Depletion: This usually requires an M-1 adjustment. Although the cost depletion formula is the same for book and tax purposes, the amount for the basis used in the computation of cost depletion will vary due to the difference in capitalization. In addition, many taxpayers will be allowed to use a larger percentage depletion deduction.

## Full Cost (FC) Method

Under the FC method, all costs incurred in exploring, acquiring, and developing oil and gas reserves in a cost center are capitalized.

1. Geological and geophysical (G & G) studies, successful and unsuccessful, are capitalized for book and financial purposes. For tax purposes, successful G & G costs are capitalized and unsuccessful G & G costs are expensed. An M-1 adjustment is required for the amount of unsuccessful G & G costs expensed.

2. Delay rental costs are capitalized for book and financial purposes.

3. Exploratory dry hole costs are capitalized for book and financial purposes. For tax purposes, all dry hole costs (exploratory or developmental) are capitalized unless the taxpayer elects to expense them. Since most taxpayers expense these costs for tax purposes, an M-1 adjustment is required.

4. Impaired or abandoned property costs remain capitalized in the cost center for book and financial purposes. For tax purposes, no deduction is allowed unless a property is totally worthless. An M-1 adjustment is required only when an abandonment is claimed for tax purposes.

5. General and administrative costs which are not associated with acquisition, exploration, and development activities are expensed. However, overhead that can be associated with acquisition, exploration, and development activities is capitalized. The costs are handled the same way for tax purposes.

6. Depletion usually will require an M-1 adjustment. In many instances, taxpayers may be able to claim a larger percentage depletion deduction in lieu of cost depletion. Even where cost depletion is claimed for book and financial purposes

because of the different capitalization rules, the amount of cost depletion allowable will vary.

Figure 3-1 below provides a comparison of the three methods: Successful Efforts, Full Cost, and Tax.

**Figure 1-3**

| Comparison of the Successful Efforts Method, Full Cost Method, and Tax | | | |
|---|---|---|---|
| **Type of Cost** | **SE** | **FC** | **Tax** |
| Geological and Geophysical | E | C | C (Successful)<br>E (Unsuccessful) |
| Acquisition | C | C | C |
| Exploratory Dry Hole | E | C | E (IRC section 165 Loss) |
| Exploratory Well, Successful | C | C | E* |
| Developmental Dry Hole | C | C | E (IRC section 165 Loss) |
| Developmental Well, Successful | C | C | E* |
| Production | E | E | E |
| Amortization Cost Center | ** | *** | ** |

**Note:** E = Expense and C = Capitalize

* = Taxpayers may elect to expense IDC. Although IDC is capital in nature, most taxpayers elect to expense IDC. The tangible portion is capitalized and depreciated. The typical well is usually two-thirds IDC and one-third tangible well equipment and facilities.

** = Property, Field, or Reservoir

*** = Country

## ACCOUNTING RECORDS

The source documents available to verify income and expenses will depend on the type of interest the taxpayer owns, but some records are common to all interest holders. Each owner should have a copy of the lease, the division order or division of interest, and check stubs or remittance slips. The lease will show the royalty interest retained, the amount of delay rentals, and the primary term of the agreement. (See Exhibit 1-1 for a copy of the mineral lease.) The division order is a necessary instrument for the operator to orderly and legally collect the oil and gas revenues and pay the correct owners of the minerals. (See Exhibit 1-3 for an example of a division order.) For accounting purposes, the information on the division order is usually condensed into a more usable format that can be put into the lease file for easy reference. Such a division of interest is prepared for each property and shows each owner's name, identification number, and fractional interest. (See Exhibit 1-4 for an example of a division of interest.) The check stubs show the type and percentage of interest owned, the quantity of minerals sold, the severance taxes withheld, and the date and amount paid to the interest owner. (A sample standardize revenue check stub can be obtained from the Council of Petroleum Accountants Society (COPAS), Arlington, Texas.)

The royalty owner will have a copy of the lease and the remittance slips, along with possible correspondence about the property.

The nonoperating working interest owner will have the following:

1. Copy of the lease

2. Remittance slips

3. Possible correspondence about the property

4. Copy of the operating agreement

5. “Authorizations for Expenditures” or AFEs

6. Periodic statements from the operator showing expenses incurred with the classification of the expenses for tax purposes.

Operator statements should not be accepted prima facie. If costs appear to be out of line, further audit work should be performed.

A comparison should be made between the actual costs incurred in drilling the well and those shown on the AFE. An AFE is a budget that must be approved by the operator and all the other working interest owners. It is detailed enough for the nonoperating working interest owners to determine whether the budgeted amounts are reasonable. If the expenses deducted are not close to the budgeted amounts and no reasonable explanation is given, then the examining officer should ask the taxpayer to obtain the invoices and contracts necessary to substantiate the deductions from the operator. The costs should be allowed if the payments were made timely to the operator and they are in line with the AFE and appear reasonable and correctly classified on the operator's statement.

The operator oversees the development, drilling, completion, and day-to-day operation of a property. The operator is almost always a working interest owner as well as an operator. In addition to the records mentioned above, the operator will generally have all of the original source documents to verify income, expenses, and capital costs on the operated property. Further, the operator is responsible for filing state reports in relation to pluggings and abandonments, well completions, etc. and will have copies of these reports.

# OIL AND GAS LEASE
## OKLAHOMA--SUIT-IN ROYALTY, POOLING

THIS AGREEMENT, made and entered into this _____ day of __________, 19 ___, by and between ____________________ hereinafter called Lessor, and ____________________, hereinafter called Lessee.

WITNESSETH:

1. That Lessor, in consideration of the sum of ____________________ Dollars, ($__________) receipt of which is hereby acknowledged, other good and valuable considerations, and the mutual covenants and agreements contained herein, does hereby grant, bargain, lease and let unto the Lessee, the land described hereinafter, for the purpose of carrying on geological, geophysical and other exploratory work, including core drilling, the right to enter upon said lands for such purposes without any additional payments, and for the purpose of drilling, mining and operating for, producing, and saving all of the oil, gas, casehead gas, casehead gasoline and all other gases and their respective constituent vapors, and constructing roads, laying pipe lines, building tanks, storing oil, building power stations, telephone lines and other structures thereon necessary or convenient for the economical operation of said land, to produce, save, take care of, and manufacture all of such substances, and also for housing and boarding employees, said tract of land with any reversionary rights therein being situated in the County of ____________________ State of Oklahoma, and described as follows to wit:

containing ____________________ acres, more or less.

2. This Lease shall remain in full force and effect for a term of ______ years and as long thereafter as oil, gas, casinghead gas, casinghead gasoline or any of the products covered by this Lease is, or can be produced.

3. The Lessee shall deliver to Lessor as royalty, free of cost, on the lease, or into the pipe line to which Lessee may connect its wells the equal one-eighth part of all oil produced and saved from the leased premises, or at the Lessee's option may pay to the Lessor for such one-eighth royalty the market price for oil of like grade and gravity prevailing on the day such oil is run into the pipe line or into storage tanks.

4. The Lessee shall pay to Lessor for gas produced from any oil well and used by the Lessee for the manufacture of gasoline or any other product as royalty 1/8 of the market value of such gas at the mouth of the well; if such gas is sold by the Lessee, they as royalty 1/8 of the proceeds of the sale thereof at the mouth of the well. The Lessee shall pay Lessor as royalty 1/8 of the proceeds from the sale of gas as such at the mouth of the well where gas is found, and where such gas is not sold or used, Lessee shall pay or tender annually at the end of each yearly period during which such gas is not sold or used, as royalty, an amount equal to the delay rental provided for in paragraph 5 hereof, and while said shut-in royalty is so paid or tendered this Lease shall be held as a producing Lease under paragraph 2 hereof.

5. If operations for the drilling of a well for oil or gas are not commenced on said land on or before the _____ day of _________________, 19___, this Lease shall terminate as to both parties, unless the Lessee shall on or before said date pay or tender to the Lessor, or for the Lessor's credit in the ____________________ Bank at ____________________, or its successors, which Bank and its successors shall be the Lessor's agent and shall continue as the depository of any and all sums payable under this Lease regardless of change of ownership in said land, or in the oil and gas or in the rentals to accrue hereunder, the sum of $_______, which shall operate as a rental and cover the privilege of deferring the commencement of operations for drilling for a period of one year. In like manner and upon like payments or tenders the commencement of operations for drilling may be further deferred for like periods successively. All payments or tenders may be made by check or draft of Lessee, mailed or delivered on or before the rental paying date, either direct to the Lessor, or to said depository Bank, and it is understood and agreed that the consideration first recited herein, the down payment, covers not only the privileges granted to the date when said first rental is payable as aforesaid, but also the Lessee's option of extending that period as aforesaid and any and all other rights conferred herein. Notwithstanding the death of the Lessor, the payment or tender of rentals in the manner above provided for shall be binding on the heirs, devisees, executors, administrators, and legal representatives of such persons.

6. If at any time prior to the discovery of oil or gas on this land and during the term of this Lease, the Lessee shall drill a dry hole, or holes on this land, this Lease shall not terminate, provided operations for the drilling of a well are commenced by the next ensuing rental paying date, or provided the Lessee begins or resumes payment of rentals in the manner and amount herein above provided for, and in this event the preceding paragraphs hereof governing the payment of rentals and the manner and effect thereof shall continue in full force.

7. In case said Lessor owes a lessor interest in the above described land than the entire and undivided fee simple estate therein, then the rentals and royalties herein provided for shall be paid to said Lessor only in the proportion that his interest bears to the whole and undivided fee. There shall be no relationship whatsoever between royalties and rentals insofar as the paragraph is concerned in determining the amount of royalties to be paid to the Lessor as provided for herein above. Should the interest of the Lessor in the above described lands increase during the term hereof by reason of any reversionary interest then the rental shall be increased at the next succeeding rental anniversary after such reversion.

8. The Lessee shall have the right to use, free of cost, gas, oil and water found on this land for its operations thereon, except water from the wells of the Lessor. When required by the Lessor, the Lessee shall bury its pipe lines below plow depth and shall pay for damage caused by its operations to growing crops on said land. No well shall be drilled nearer than 200 feet to the house or barn on said premises as of the date of the Lease without the written consent of the Lessor. Lessee shall have the right at any time during, or after the expiration of this Lease to remove all machinery, fixtures, houses, buildings and other structures placed on said premises, including the right to draw and remove all casing, but Lessee shall be under no obligation to do so, nor shall Lessee be under any obligation to restore the surface to its original condition, where any alterations or changes were due to operations reasonably necessary under the terms of this Lease.

9. If the estate of either party hereto is assigned, and the privilege of resigning in whole or in part is expressly allowed, the covenants hereof shall extend to the heirs, devisees, executors, administrators, successors, and assigns, but no change of ownership in the land, or in the rentals, or in the royalties or in any sum due under this Lease shall be binding on the Lessee until it has been furnished with either the original recorded instrument of conveyance, or a duly certified copy thereof, or a certified copy of the will of any deceased owner and of the probate thereof, or a certified copy of the proceedings showing the appointment of an administrator or executor for the estate of any deceased owner, whichever is appropriate, together with all recorded instruments of conveyance, or duly certified copies thereof necessary in showing a complete chain of title out of the Lessor to the full interest claimed and all advance payment of rentals made hereunder before receipt of such documents shall be binding on any direct or indirect assignee, grantee, devisee, administrator, executor or heir of Lessor.

10. If the leased premises are now or shall hereafter be owned in severalty or in separate tracts, the premises shall nevertheless be developed and operated as one Lease and there shall be no obligation on the part of the Lessee to offset wells on separate tracts into which the land covered by this Lease may hereafter be divided by sale, devise, descent, or otherwise, or to furnish separate measuring or receiving tanks. It is hereby agreed that in the event this Lease shall be assigned as to a part or as to parts of the above described land and the holder or owner of any such part or parts shall make default in the payment of the proportionate part of the rent due from him or them, such default shall not operate to defeat or affect this Lease insofar as it covers a part of said land upon which the Lessee or any assignee hereof shall make due payment of said rentals.

11. Lessor hereby warrants and agrees to defend the title to the land herein described and agrees that the Lessee, at its option may pay and discharge, in whole or in part any taxes, mortgages, or other liens existing, levied, or assessed on or against the above described lands, and in the event it exercises such option, it shall be subrogated to the rights of any holder or holders thereof and may reimburse itself by applying to the discharge of any such mortgage, tax, or other lien, any royalty or rental accruing hereunder.

12. Notwithstanding anything in this Lease to the contrary, it is expressly agreed that if the Lessee shall commence operations for the drilling of a well at any time while this Lease is in force, this Lease shall remain in full force and effect and its terms shall continue so long as such operations are prosecuted, and if production results therefrom, then as long as such production continues.

13. If within the primary terms of this Lease, production on the leased premises shall cease from any cause, this Lease shall not terminate provided operations for drilling of a well shall be commenced before or on the next ensuring rental paying date; or provided Lessee begins or resumes the payment of rentals in the manner and amount herein above provided for. If after the expiration of the primary term of this Lease, production on the leased premises shall cease from any cause, this Lease shall not terminate provided Lessee resumes operations for drilling a well within 60 days from such cessation, and this Lease shall remain in force during the prosecution of such operations, and, if production results therefrom, then as long as production continues.

14. Lessee may at any time surrender or cancel this Lease in whole or in part by delivering or mailing such release to the Lessor, or by placing the release of record in the County where said land is situated. In this Lease is surrendered or canceled as to only a portion of the acreage covered hereby, then all payments and liabilities thereafter accruing under the terms of this Lease as to the portion canceled, shall cease and terminate and any rentals thereafter paid may be apportioned on an acreage basis, but as to the portion of the acreage not released the terms and provisions of this Lease shall continue and remain in full force and effect for all purposes.

15. All provisions hereof, express or implied, shall be subject to all federal and state laws, and the orders, rules, or regulations of all governmental agencies administering the same, and this Lease shall not be in any way terminated wholly or partially, nor shall the Lessee be liable in damages for failure to comply with any of the express or implied provisions hereof if such failure accords with any such laws, orders, rules or regulations. If Lessee shall be prevented during the last year of the primary term hereof from drilling a well hereunder by the order of any constituted authority having jurisdiction, or if the Lessee shall be unable during said period to drill a well hereunder due to the equipment necessary in the drilling thereof not being available on account of any cause, the primary term of this Lease shall continue until one year after said order is suspended and/or said equipment is available, but the Lessee shall continue to pay delay rentals in the manner herein above provided for during such extended term.

16. Lessee, at its option, is hereby given the right and power to voluntarily pool or combine the acreage covered by this Lease, or any portion thereof, with other lands, 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 leased premises so as to promote the conservation of oil and gas for other hydrocarbons in and under, or that may be produced from said premises, such pooling to consist of tracts contiguous to one another and to be into a unit or units not exceeding 80 acres each in the event of an oil well, or into a unit or units not exceeding 640 acres each in the event of a gas well. Lessee shall execute in writing and record in the county records of the county in which the land herein leased is situated, 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, the Lessor shall receive on production from a unit so pooled only such portion of the royalty stipulated herein above 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.

17. This Lease together with all its terms, conditions, stipulations and provisions shall extend to and be binding on all successors whatsoever of said Lessor or Lessee.

IN WITNESS WHEREOF, this instrument is executed on the day and year first set out herein above,

| Name | Social Security No. |
|---|---|

# Mineral Deed

*(For Filing Only)*

**Know All Men By These Presents:**

**That** ______________________________________________________

______________________________________________________

______________________________________________________

of _________________________ hereinafter called Grantor, (whether one or more) for and in consideration of
*(Give exact Post Office Address)*

the sum of______________________ Dollars, ($_______) cash in hand paid and other good and valuable

considerations, the receipt of which is hereby acknowledged, do ___________________, hereby grant, bargain,

sell, convey, transfer, assign and deliver unto ___________________ of _________________________,
*(Give exact post office address)*

hereinafter called Grantee (whether one or more) an undivided _______________________________________

interest in and to all of the oil, gas and other minerals in and under and that may be produced from the following

described lands situated in ___________________ County, State of ___________________ to-wit:

containing ___________________acres, more or less, together with the right of ingress and egress at all times for the purpose of mining, drilling. exploring, operating and developing said lands for oil, gas, and other minerals, and storing, handling, transporting and marketing the same therefrom with the right to remove from said land all of Grantees property and improvements.

This sale is made subject to any rights now existing to any lessee or assigns under any valid and subsisting oil and gas lease of record heretofore executed; it being understood and agreed that said Grantee shall have, receive, and enjoy the herein granted undivided interest in and to all bonuses, rents, royalties and other benefits which may accrue under the terms of said lease insofar as it covers the above described land from and after the date hereof precisely as if the Grantee herein had been at the date of the making of said lease the owner of a similar undivided interest in and to the lands described and Grantee one of the lessors therein.

Grantor agrees to execute such further assurances as may be requisite for the full and complete enjoyment of the rights herein granted and likewise agrees that Grantee herein shall have the right at any time to redeem for said Grantor by payment, any mortgage, taxes, or other liens on the above described land, upon default in payment by the Grantor, and be subrogated to the rights of the holder thereof.

TO HAVE AND TO HOLD The above described property and easement with all and singular the rights, privileges, appurtenances thereunto or in any wise belonging to said Grantee herein, ___________________ heirs, successors, personal representatives, administrators, executors, and assigns forever, and Grantor does hereby warrant said title to Grantee ___________________ heirs, executors, administrators, personal representatives, successors and assigns forever, and does hereby agree to defend all and singular the said property unto the said Grantee herein ____________ heirs, successors, executives, personal representatives, and assigns against all and every person or persons whomsoever lawfully claiming or to claim the same, or any part thereof.

WITNESS Grantors, hand this _____ day of _____________________, 19___.

______________________________ ________________________________________

Kraftbilt 601-95 P.O. Box 800
Tulsa, OK

COPAS — 1995
Recommended by the Council of Petroleum
Accountants Society

# Sample

## EXHIBIT “ ”

Attached and made a part of ______________________________________________
_______________________________________________________________
_______________________________________________________________
_______________________________________________________________

# ACCOUNTING PROCEDURE
# JOINT OPERATIONS

## 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 it 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 deny or 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, to 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 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 in the Joint Account. All audits will be conducted pursuant to Section I, Paragraph 5.

☐ The Parties agree that the 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 the results shall be binding on all Parties. All votes must be confirmed 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 I), 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 those 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-needed 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, means, 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 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. 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. Longshoremen and Harbor Workers (ULS&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, telecommunications 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 |
| ____________ | ☐ | ☐ ___ | ____________________ | ☐ ____________ |
| ____________ | ☐ | ☐ ___ | ____________________ | ☐ ____________ |
| ____________ | ☐ | ☐ ___ | ____________________ | ☐ ____________ |
| ____________ | ☐ | ☐ ___ | ____________________ | ☐ ____________ |
| ____________ | ☐ | ☐ ___ | ____________________ | ☐ ____________ |

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 collection 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 work over, 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 work over operations, with the rig or other units used in work over, 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 is 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 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 interests 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] work over 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 above will be used for calculating construction or catastrophe overhead. For purposes of calculating overhead, the cost of drilling and work over 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 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 on 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 costing 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 IV, 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

(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 costing 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 providing 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.

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 interests. 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.

**DIVISION ORDER**

**Number 321**

**Effective with Date of First Production**

TO: LAKELAND PETROLEUM CO.
429 3rd Ave. E.
Delta, Montana 10961

This division order applies to oil, gas condensate and/or distillate or the proceeds from the sale there of produced from the following described well and land, to wit:

LAKELAND PETROLEUM CO. PBY VG RV A: COLT #1 UNIT WELL, comprising 320 acres, more or less, being the South Half (572) of Section 8, Township 35 North, Range 6 West, Falcon County, Montana.

Each of the undersigned certifies and guarantees the interest set out on Exhibit "A", attached hereto and made a part hereof, opposite the name of the undersigned is the interest owned by the undersigned in the oil, gas, condensate and/or distillate or proceeds from the sale thereof from the above described property, and you will give credit for such interest shown on Exhibit "A" according to the following directions:

1. Until further written notice, you or your assignees, nominees or vendees are authorized to purchase or to deliver to other purchasers for the account of the undersigned and to receive the proceeds thereof, the oil, gas, condensate and/or distillate from the above described property.

2. For all gas taken hereunder, the undersigned will be paid the price received by Lakeland Petroleum Co. for such gas, under any presently existing or any future contracts for the sale of gas, at the delivery point, less costs incurred in making delivery of such gas from the wellhead including, but not by way of limitation, the costs of gathering, dehydrating, compressing, treating, and transporting the gas.

3. For all oil, condensate, distillate or other liquid hydrocarbons taken hereunder, the price therefore shall be the same price received by Lakeland Petroleum Co. therefore at the well, after deducting therefrom a reasonable sum to cover the costs and expenses of treating and marketing such product. If, in order to market such products, it is necessary to transport same by truck or barge to a marketing point, then, in that event,

Lakeland Petroleum Co. is authorized to deduct from the proceeds for such products the trucking or barging charges. Proper deductions will be made for water, dirt, sediment, and other impurities and corrections for temperature will be made in accordance with established rules prevailing at the time and place of delivery.

4. In the event the price received by Lakeland Petroleum Co. and paid to the undersigned for the oil, gas, condensate and/or distillate from the above described property is in excess of the maximum legal price that may be collected and paid, then the undersigned agrees to refund to you such excess with interest as determined under the applicable Federal or State Laws, rules, and regulations.

5. The undersigned agrees to indemnify you and hold you harmless from any liabilities for any tax imposed or assessed against the undersigned's interest hereunder and hereby authorizes you to deduct and pay such tax or taxes.

6. If the proceeds accruing to any interest hereunder should amount to less than Five Dollars ($5.00) per month, you are hereby authorized to withhold payment until such accruals amount to $5.00 or to account for such proceeds on an annual basis, at your election.

7. Each of the undersigned warrants the title to the particular interest credited to the undersigned herein but, without impairment of such warranty, agrees that in case of any adverse claim of title, the undersigned will furnish a bond satisfactory to you, executed by a surety company as indemnity against such claim and further agrees that you may retain the purchase (or sales) price of the oil, gas, condensate and/or distillate without any obligations to pay interest thereon until such bond be furnished, or until the dispute as to ownership be settled in a manner satisfactory to you. Each of the undersigned hereby ratifies and confirms the oil and gas lease or leases and assignments and/or subleases pertaining thereto covering the tract or tracts as to which the undersigned is credited with an interest, and recognizes said agreements to be presently valid and subsisting in accordance with its or their terms, and the consideration for the execution of this ratification is the proceeds from production obtained and to be obtained from the unit well.

8. The undersigned agrees to notify you in writing of any change in ownership or of interest and to furnish you with a certified copy of instrument evidencing such change. Any transfer, assignment or conveyance of any interest in said oil or gas shall be made subject to this division order and effective at seven o'clock A.M. on the first day of the calendar month following receipt of such certified copy of instrument by you.

9. You are hereby relieved of any responsibility for determining when any of the interest shown on Exhibit "A" shall increase, diminish, be extinguished, or revert to others as a result of payments from said interests or as a result of the increase or decrease in production, and you are hereby authorized to continue to remit, pursuant to the division of interest set forth on Exhibit "A" attached hereto until you receive notice in writing to the contrary by mail addressed to you at the address shown above, together with a certified copy of the instrument evidencing such change.

10. With respect to any interest in the statement of ownership and order of division which is credited to a married woman, the husband of such woman joins herein and becomes a party hereto and authorizes and directs Lakeland Petroleum Co., its successors and assigns, to receive and market production under the terms hereof and to pay the value thereof to his wife in the proportion set forth on Exhibit "A," which such payment shall be in full and complete discharge of all obligations hereunder, in the same manner as though such payment had been made directly to him or to him and his wife jointly. Each interest owner warrants and represents that his or her marital status has remained constant subsequent to his or her acquisition of interest in the lands described.

11. Each owner of a working interest in the land described above warrants that the royalties or overriding royalties applicable to the working interest owned by such owner are correctly set out and owned as shown on this division order. Each such owner of a working interest hereby authorizes and directs you to make payment for all royalties or overriding royalties that may become due and attributable to the working interest of the undersigned in accordance with this division order. Each such owner of a working interest in said land agrees that you will be free of any liability for payment made in accordance with this division order.

12. This division order shall be effective as to each party signing same irrespective of whether or not any other party whose name appears in Exhibit "A" attached hereto executes this instrument or any other instrument of similar import.

13. This division order shall insure to the benefit of Lakeland Petroleum Co. and the undersigned, their heirs, successors, and assigns; and, the undersigned, and each of them, by executing this division order, hereby agree that the persons, partnerships, corporations, or firms to whom you may sell or market all, or any part, of the production produced from or allocated to the lands described above may make payment to you for all such production purchased from the undersigned; that they will look solely

to you for payment of their interest in such production which is being purchased from them hereunder; and that, insofar as concerns and to the extent of their interest owned hereunder, that they will hold harmless, protect and indemnify all purchasers from you against any and all claims, damages, and expenses of whatsoever nature in connection with the purchase of such production by said purchaser and the payment to you for same.

| WITNESSES: | SIGNATURE OF OWNER: | DATE: |
|---|---|---|
| ATTEST: | CASPER DEVELOPMENT INC. | |
| __________ | ______________________ | ________ |
| __________ | | |
| | ADDRESS: 300 Sixth Street<br>Citation, TX 80853 | |
| | EMPLOYER IDENTIFICATION: 32-1234567 | |

| WITNESSES: | SIGNATURE OF OWNER: | DATE: |
|---|---|---|
| ATTEST: | CASPER DEVELOPMENT INC. | |
| __________ | ______________________ | ________ |
| __________ | ADDRESS: ______________________ | |
| | ______________________ | |

FPC - Colt #1 Monte Carlo Field
Falcon County, Montana

**EXHIBIT A**

| OWNER NAME AND ADDRESS | DECIMAL INTEREST |
|---|---|
| Helen Mary Allen, First Street, Delta, Montana 10456 | .03668162 RI |
| Charles Gary Bates, 426 Ada, Courier, Montana 10455 | .00156666 RI |
| Mary Joyce Cottey, 65631 Fifth Ave. N.Y. City 00010 | .00013682 RI |
| Delta Industrial Development Corporation, Incorp.<br>426 3rd Ave. W. Delta, Montana 10456 | .01563219 RI |
| Jack C. Coker, Jr., Second St., Delta, Montana 10454 | .02368542 RI |
| Roger P. Tyler, Jr., Third St., Gran Prairie, TX 70855 | .05425169 RI |
| Charles G. Regis, Fourth St., Delta, Montana 10454 | .00443594 ORRI |
| Katherine C. Hood, Fifth St,, Delta, Montana 10456 | .02752420 ORRI |
| Martha B. Mills, 346 Scott, Delta, Montana 10456 | .01240234 ORRI |
| Casper Development Inc.<br>Sixth Street, Citation, TX 80853 | .06218417 ORRI |
| Jack C. Elon, Seventh St., Delta, Montana 10454 | .03430456 ORRI |
| Roger P. Coker, 4236 Vance, Gran Prairie, TX 70855 | .00295729 ORRI |
| Horace A. Keene, Eighth Street, Delta, Montana 10455 | .04936223 WI |
| Frank K. Loras, Ninth Street, Delta, Montana 10455 | .62368091 WI |
| Jake Marin, Tenth Street, Gran Prairie, TX 70855 | .04231047 WI |
| Suspense | .00888349 |
| TOTAL | 1.00000000 |

**Note:** The interests of Jasper and Katherine C. Hood have the option to convert to a WI after payout. If payout occurs, additional calculations will be necessary.

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**Exhibit 1-4**

## Division of Interest Breakdown

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                         DIVISION OF INTEREST BREAKDOWN                ** K10 **
                                   FOR PROPERTY

DATE   JANUARY 29, 1983                                        ERYAV122  PAGE 001

LEASE NUMBER         BACK

BASE  WL Z PROD DISB RUN                                 LEASE NAME

00640 04 0   1    7                                      J. XYZ    SO ALV CAD WF


T A/C OWNER P PART  MISC OWNER NAME              SUSP REFERENCE    DECIMAL    REVERTING    EFF.

/      NO.  / CODE  PROD                         CODE                OF        INTEREST    DATE
I           P       PMT                                            INTEREST

1 521 62000 0            A OWNER                      G2102204     .8193711                1081
2 521 14314 0            B OWNER                      G7110119     .0761719
2 521 15859 0            C OWNER                      G1040606     .0761719

3 521 44257 0            D OWNER                      G7110119     .0127148
3 521 57891 0            E OWNER                      G7110119     .0127148
3 521 59237 0            F OWNER                      G2102204     .0028555                1081

                                                                  1.0000000    .0000000
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## Chapter 2

## OIL AND GAS INDUSTRY ISSUES

### ISSUES RELATED TO AN OIL AND GAS ENTITY AND ACTIVITY -- OVERVIEW

When an examining officer receives a tax return that is in the business of oil and gas or has related oil and gas business activities, one needs to scrutinize the return carefully to determine its potential for examination. There are many different areas that could generate an issue or issues that need to be looked at during the examination. This section of the MSSP audit techniques guide discusses specific areas that are typical to an oil and gas entity or activity and audit techniques that can be of use to ensure proper coverage of the specific areas.

North Texas District conducted audits on activity codes 219 and 215 corporations related to the oil and gas industry. It was discovered that some items which appeared productive on the face of the return were in fact not productive for this industry. However, items that appeared reasonable upon the first inspection of the tax return were in fact productive.

### Unproductive Issues

Cost of goods sold on oil and gas working interest returns commonly runs 80 to 90 percent of gross receipts. The great majority of the cost is lease operating expenses (LOE), a "catch-all" classification for all direct costs connected with running a productive oil and gas well. It was discovered that LOE was virtually unproductive in our examinations. Other major components of cost of goods sold, IDC and dry hole costs were more productive.

The oil and gas industry is highly "capital-intensive." This is due to the enormous cost of developing properties and the low probability of success. Consequently, retained earnings of oil and gas companies are frequently in the tens of millions of dollars. Retained earnings was found to be unproductive. The taxpayers, as a general rule, maintained detailed plans for acquisition and development of properties which would cost in the tens of millions and upwards to the hundreds of millions of dollars.

### Productive Issues

Geological and geophysical (G & G) costs are frequently expensed on all properties, whether they were leased or not. If the taxpayer has acquired part or all of the areas surveyed, the G & G expenses are part of the leasehold cost. They are part of the basis for cost depletion and for computing gain or loss at the date of disposition, but they are not a current expense.

Depletion includes cost depletion as well as percentage depletion. One should secure a detailed depletion schedule to determine which properties have percentage depletion rather than cost. Also determine how close the cost depletion available is to the percentage depletion. Your adjustment will probably only be the difference between cost depletion and percentage depletion. To examine cost depletion, the services of a petroleum engineer is required. The engineer will evaluate the reserve computation. However, one should take caution if an adjustment is made to percentage depletion. Regular income tax will be increased but alternative minimum tax could be affected, if applicable, through the depletion tax preference. The alternative minimum tax preference item for excess depletion was repealed by the Energy Policy Act of 1992 for taxable years beginning after December 31, 1992, for independent producers. Thus, examining officers should not be concerned with the effect of making an adjustment to percentage depletion on alternative minimum tax after the calendar year of 1992. However, the issue is still viable in a fiscal year that straddles 1992 and 1993.

Percentage depletion can be a very productive issue, particularly when the taxpayer has obtained proven property with low basis. Overhead allocation for depletion can produce major changes to the 50 percent of net income per property limitation. The taxpayer is required to be consistent in allocating overhead, and to have a reasonable basis for the allocation of costs. If a change in percentage depletion would have a material effect on the tax liability, the methods used by the taxpayer in allocating overhead should be scrutinized.

IRC section 29 provides a tax credit for the production of fuel from nonconventional sources. The Revenue Reconciliation Act of 1990 redesignated "old" IRC section 29(b)(5) as section 29(b)(6) and added "new" IRC section 29(b)(5). The new section modified the energy incentive credit. This modification is covered in depth in the audit techniques handbook, IRM 4232.8:800. If this issue is encountered in the course of an examination, PIP should be contacted. Also, examiners should make a referral to the Engineering program utilizing the services of an engineer.

## Unique Issues

### Alternative Minimum Tax -- Excess Depletion Preference

In *Hill v. United States*, 21 Cl. Ct. 713 (1990), the court held that adjusted basis referred to in IRC section 57(a)(8) -- currently IRC section 57(a)(1) -- includes unrecovered depreciable tangible costs. As a result, taxpayers filed claims for refunds increasing the adjusted basis in the property when computing the excess percentage depletion to be reported as a tax preference item subject to alternative minimum tax.

The Supreme Court, reversing the lower court, held in *United States v. Hill*, 113 S.Ct. 941 (1993), that the adjusted basis does not include depreciable drilling and development costs in mineral deposits for determining the tax preference item of depletion for alternative minimum tax purposes. This decision was rendered on January 25, 1993, during the filing season for 1992 income tax returns.

Even though the issue "dies out" on 1991 claims or original returns, examining officers should pay particular attention to the adjusted basis of property for alternative minimum tax purposes in 1992. Even though taxpayers are not computing excess depletion in accordance with the Hill decision, they may not have adjusted the basis "back" to the amount of basis computed without reference to Hill.

This issue will not be of concern after 1992. The Energy Policy Act of 1992 eliminated the excess depletion as an alternative minimum tax preference item. The change in law applies to independent producers and royalty owners, not integrated oil companies, and is effective for taxable years beginning after December 31, 1992.

## Intangible Drilling Costs Preference - Tax Benefit Rule

The preference for IDC equals the amount by which excess IDC for the tax year exceeds 65 percent of the net income from oil and gas properties for that year. Net income from oil and gas properties is the excess of the aggregate amount of gross income, within the meaning of IRC section 613(a), from all oil and gas properties of the taxpayer received or accrued by the taxpayer during the tax year, over the amount of any deductions allocable to such properties (including percentage depletion) reduced by the excess IDC.

One oil and gas publication, *Income Taxation of Natural Resources 1992*, C.W. Russell, takes the position that the tax benefit rule under IRC section 59(g) can be applied in instances where a taxpayer is subject to both the IDC preference and the depletion preference. According to Russell, the rule applies because each dollar of depletion preference generates two dollars of preferences because the depletion also decreases net income from oil and gas.

See Exhibit 2-2 for an illustration of how the tax benefit rule applies in this situation.

There is no published position on this situation at this time. If an examining officer encounters this issue, technical advice should be requested.

This potential issue will not be of concern with regard to independent producers and royalty owners after 1992. The Energy Policy Act of 1992 repealed the alternative minimum tax IDC preference item for independent producers and royalty owners, not integrated oil companies. The repeal is effective for taxable years beginning after December 31, 1992.

## Uniform Capitalization Rules

Final regulations were adopted in August 1993 (TD 8482, August 6, 1993). The final regulations made several changes to the temporary regulations but still leave some issues unresolved. Still some in the oil and gas industry advocates that the uniform capitalization rules of IRC section 263A do not offer sufficient guidance as to the application of the rules to the oil and gas industry.

### Capitalization of Delay Rentals

It is the position of the industry that delay rentals are pre-production period costs which were not intended to be affected by IRC section 263A. This issue is not specifically addressed in any regulations or IRS notices.

Prior to the effective date of the final regulations, the Service's position was that delay rentals should be capitalized as an indirect expense incurred in improving or developing an oil and gas leasehold, citing Temp. Treas. Reg. section 1.263A-1T(b)(2)(iii). Pre-production costs are addressed in the final regulations, Treas. Reg. section 1.263A-2(a)(3)(ii). However, neither the temporary nor final regulations specifically address delay rentals because guidelines for specific industries are not included in them. Thus, if an examiner has a delay rental issue, PIP should be consulted and technical advice should be requested.

### Capitalization of Interest Expense

The final regulations under section 1.263A(f), as a general rule, require owners of oil and gas properties to capitalize any interest expense associated with the production of designated property as defined in the regulations. The interest expense to be capitalized is that which is incurred during the production period that could have been avoided if the production expenditures had been used to repay or reduce the owner's outstanding indebtedness. This method is referred to as the "avoided cost" method. It assumes that debt of the owner would have been repaid or reduced if the production expenditures had not been incurred, without regard to the owner's actual subjective intentions or to restrictions against repayment or use of the debt proceeds.

The industry has raised concerns over the definition of real property for the interest rules. The final regulations define real property as including permanent structures which include foundations, oil and gas pipelines, derricks, and storage equipment.

## Assistance in IRC Section 263A

If one encounters a uniform capitalization issue with regard to the oil and gas industry, one of the following should be considered:

1. Consult the PIP team in Midstates Region to determine if there is an ISP issue on your concern.

2. Request technical assistance through the technical section of Quality Measurement Staff or the staff that directs technical assistance to District Counsel.

3. Request technical advice from National Office.

## General Issues (Non-Oil and Gas)

Due to hard times in the oil and gas industry, bad debts and liquidations of subsidiaries have become common. These two areas, bad debts from subsidiaries and worthless stock of subsidiaries, have been very productive issues. When a controlled group files a consolidated return, they are generally barred from claiming any losses on transactions within the related group even if the subsidiary is liquidated, or the property is disposed of outside the group. Treas. Reg. section 1.1502-20 generally disallows a deduction for any loss recognized by a member of a consolidated group with respect to the disposition of the stock of a subsidiary.

Unrecognized income from forgiveness of indebtedness of a subsidiary has been productive when the taxpayers have property related to the forgiven debt and have not adjusted the tax attributes of the property in computing the gain or loss. Generally, they excluded the income from the forgiveness and then claimed a loss or reported a lesser gain than they should have on the disposition. They are usually entitled to the exclusion, but they are required to reduce their NOL carryover, or the basis of the property, or other tax attributes.

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**Exhibit 2-1**

# TAXPAYERS SUBJECT TO BOTH DEPLETION PREFERENCE AND IDC PREFERENCE

COMPARISON OF TAX PREFERENCE CALCULATION:

| | (1) | (2) |
|---|---|---|
| Net Oil and Gas Income | $146,643 | $146,643 |
| Add: Depletion Preference | N/A | $32,990 |
| Adjusted Net Oil and Gas Income | $146,643 | $179,633 |
| Excess IDC | $261,092 | $261,092 |
| Less: 65 Percent of Net Oil and Gas Income | $95,318 | $116,761 |
| IDC Preference | $165,774 | $144,330 |

1. Net income from oil and gas properties computed according to IRC section 57(a)(2)(C). The excess intangible drilling costs tax preference is according to IRC section 57(a)(2)(A) and (B). No tax benefit reduction is allowed under IRC section 59(g) in this calculation.

2. Net income from oil and gas properties computed according to IRC section 57(a)(2)(C), but it is adjusted to give effect to a purported tax benefit. The "so called" tax benefit calculation is based on an interpretation of IRC section 59(g).

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## Chapter 3

## OIL AND GAS AUDIT TECHNIQUES

### EXAMINATION OF AN OIL AND GAS ENTITY AND ACTIVITY

Once an examiner receives a tax return for examination, a precontact analysis of the return should be conducted. Below are some suggestions that are applicable to oil and gas returns when preplanning an examination.

Analyze the M-1 carefully for the book to tax return differences. The following items can usually be found relating to an operator: percentage depletion; impairment of unproven properties; abandonments; and intangible drilling costs (IDC). Differences in depreciation and timing issues are similar to those in other industries.

Analyze the detailed depletion schedule for cost depletion versus percentage depletion, and ratio of expenses to income on each property. Decide whether there is any potential in examining percentage depletion. It you are going to examine it, decide which properties you will examine; it is not an all or nothing proposition. A sample of the universe of depletable properties is usually selected for examination.

Inspect "Other Deductions" carefully. This is usually where you'll find such items as geological and geophysical (G & G) expenses, professional fees, and consultants. Accounts of this nature should be examined, if they are material in amount, for capital expenditures treated as current expenses.

The balance sheet should be analyzed for changes in depreciable and depletable assets. They can indicate acquisitions and/or dispositions of properties. Also analyze the depreciation schedule, Schedule D, and Form 4797 for confirmation of the changes.

Loans to and from shareholders reflected on the balance sheet should be scrutinized closely. This can lead you to capital contributions being treated as a loan to qualify for tax-free return of capital to the shareholder and an interest deduction to the company, or to forgiveness of indebtedness to the shareholder. Scrutinize the eliminations column of the consolidated balance sheet for loans within the consolidated group. Treating capital investment in subsidiaries as loans seems to be fairly common in medium to large sized companies.

### Engineering Referral

Examiners should determine as early as possible in the audit if the assistance of an engineer is needed. Engineering referrals are not mandatory in all cases. An engineer can still be used to assist in the examination even though a case does not meet the mandatory referral criteria.

District or regional directives and Internal Revenue Manual 42(16)0 should be consulted for information on the engineering program and assistance that is available to revenue agents. For example, North Texas District examining officers should consult Regional Commissioner Memorandum 42-24, Rev. 5, Engineering Program, dated May 4, 1984.

There are certain cases that meet the criteria for a mandatory referral to the engineering program. Internal Revenue Manual section 42(16)2.2 sets out the types of returns that are mandatory referrals. They are the following:

1. All corporate returns, including Form 1120S, with assets of $10,000,000 and over. Returns of banks, trust companies, insurance carriers or agents, credit agencies, and security brokers are excluded and ordinarily will not be referred for engineering assistance.

2. All partnerships and joint venture returns with annual gross receipts or total deductions of $1,000,000 and over.

3. All returns with a fair market value issue of $500,000 and over.

## INITIAL INTERVIEW QUESTIONS

The following questions are suggested additions to normal initial interview questions for any income tax examination. They should be adapted to the particular circumstances of the taxpayer under examination.

- Have there been any assignments of income (royalties, production payments, etc.)? If so, to whom and for what purpose?

- Are you an operator, working interest holder, royalty interest holder, or a combination of these (that is, operator and working interest holder)?

- If you are an operator, how is your fee computed and were you audited by any governmental (federal or state) regulatory agency?

- If you are not the operator, who is the operator of each property? What records do you get from the operator?

- Are contracts with leaseholders and operators, etc. available? If not, when will they be?

- Are the division orders for your well participations available?

- Are you responsible for preparing or filing any state regulatory reports? For example, reports are filed in the State of Texas with the Texas Railroad Commission. (See Exhibits 3-1, for descriptions of forms required to be filed with the State of Texas.) The types of reports required to be filed with other states may differ. The state regulatory agency needs to be consulted.

- Have any audits been performed on any of the operators by the joint interest holders?

- Do you capitalize or expense IDC? Have there been any changes in your treatment of IDC since the inception of your business?

- Did you buy or sell any leases, or make any other conveyances during this year? If there was a sale, did you recapture IDC? Did you enter into any sharing agreements, such as poolings or unitizations?

- How did you compute depletion on the return?

- Are there any carry-overs of depletion?

- Did you receive or pay for any test well contributions this year (that is, dry hole or bottom hole contributions)?

- Is there any coding within your accounting system that identifies operated working interest properties from non-operated properties?

- For financial purposes do you periodically evaluate your unimproved properties to determine whether they have been impaired (partially worthless)? If so, how do you account for impaired leases?

- How are you allocating overhead expenses among properties for the percentage depletion limitation computation (that is, gross income, direct expenses, etc.)?

- Was the income from each property reduced by the bonus exclusion for the percentage depletion computation?

- If you are the operator, do you have an in-house geologist or engineers that provide you information and data to develop properties or purchase already producing properties?

## INITIAL INFORMATION DOCUMENT REQUEST

Certain records are necessary to begin an examination of an oil and gas activity. These should be requested in the first Information Document Request (IDR), Form 4564, sent to the taxpayer. Also, the taxpayer should be requested to be present at the very beginning of the audit.

The following list of items, which should be requested on the initial IDR, cover only oil and gas issues. Not all items will fit all taxpayers and should be adjusted to fit the particular taxpayer under examination. The basic records needed are as follows:

1. Charts of cost centers, lease names, and numbers.

2. Detailed depletion schedules related to the tax return.

3. For leaseholds abandoned during this tax year, records to show the expiration or release of the lease.

The following should also be identified in the initial IDR. This information should be requested to be made available, within a reasonable time period, for specific properties which will be identified later:

1. Joint venture/operator agreements in effect during 19___.

2. Reports of any joint interest or operator audits.

3. Copies of division orders.

4. Whether or not you are the operator on all properties, operator's reports (joint interest billings), and Authorization for Expenditures (AFEs).

5. Plug and abandonment reports for dry holes claimed for 19___.

## ACCOUNTING METHODS

Before probing into specific accounts and items, ascertain what accounting method the taxpayer is using. Below are some suggested questions and audit techniques for use in making this determination.

1. Ask the taxpayer what method of accounting they use for financial purposes. Is the method successful efforts (SE) or full cost (FC) and cash or accrual?

2. Obtain the adjusting entries which convert book and financial income to taxable income.

3. Look for M-1 adjustments in the following areas:

    a. SE Method

        1) Items deducted on the books as an expense that should not be included on the tax return:

            a) Impairments.

b) Dry-hole and bottom-hole contributions.

2) Items deducted on the tax return that should not be included on the books as an expense:

a) IDC.

b) Dry holes [developmental wells].

3) Items deducted as an expense on both the books and the return, but the amounts may vary:

a) G & G costs.

b) Depletion.

c) Abandonments.

d) Depreciation.

b. FC Method

1) All items deducted as expenses on the books are the same on the tax return.

2) Items deducted on the tax return that should not be included on the books as an expense:

a) IDC.

b) Dry holes [developmental wells].

c) G & G costs.

3) Items deducted as expense on both the books and the return, but the amounts may vary:

a) Depletion.

b) Depreciation.

## PROPERTY DEFINITION

The definition of property was previously discussed Chapter 1 in the section entitled "General Description of the Industry." Below are audit steps that should be followed only if the examiner determines that a material distortion in the property definition is likely.

1. Ask the taxpayer what definition they use for property in computing depletion (that is, well, prospect, lease, etc.).

2. Compare this definition to the IRS definition, set out in IRC section 614, to determine if a material distortion has occurred. If the taxpayer states that it uses the well or prospect, it has an incorrect property definition for income tax purposes.

3. Request copies of the taxpayer's depletion schedules for the current, prior, and subsequent years. If the taxpayer has the well account numbers on the schedules, compare the groupings of these account numbers between years to see if the taxpayer is changing the property definition each year to obtain the best deduction.

4. If you wish to test some properties to determine whether the definition has been complied with, the following steps should be followed:

    a. Select a sample of properties.

    b. Request the lease file on each property.

    c. Review the lease and determine what tracts make up the lease and what types of interest were owned on each lease.

    d. Have the taxpayer provide you with a map or plat that outlines the tracts that make up the property as it was used for claiming deductions on the tax return.

    e. Compare the taxpayer's definition to the IRS definition of property.

        1) Each different type of interest (working interest, royalty interest, etc.) is treated as a separate property.

        2) The tracts or parcels of land must be contiguous (that is, having a common side) and acquired from the same person on the same day. See the illustration in Chapter 1.

        3) Separate oil and gas deposits on each tract will be treated as one property, unless an election is made to treat them as separate properties. To qualify for separate property treatment, the taxpayer must account for the production from each deposit separately.

    f. If an incorrect definition was used by the taxpayer, determine whether a clear and convincing basis exists to make the change.

1) If there is not a clear and convincing basis, the property definition will be accepted as established by the taxpayer pursuant to Rev. Proc. 64-23, 1964-1 (Part 1) C.B. 689.

2) If a clear and convincing basis exists occurred, correct the deduction claimed using the correct property definition. Increase the sample size to correct the property definition on any properties that would cause a material distortion of the tax deduction in question.

**Unitization**

1. Ask the taxpayer if any new unitizations or pooling agreements were entered into during the year under audit.

   a. If so, ask the taxpayer if any payments were to be paid or received as equalization payments.

   b. If payments were made or received, determine if the taxpayer handled them correctly.

2. Compare the depletion computation for the prior and subsequent years with the year under examination. The addition of a property with the word "unit" in its name might indicate a current unitization. The deletion of one or more properties, which appeared to be making a profit, and the addition of another might indicate current unitization.

3. Check unitized properties for matching of income and expenses. The taxpayer may shift the expenses from a producing property to a nonproducing or marginal property. Legal expenses incurred relating to the formation of a unit have been held as a deductible expense in *Fields v. Commissioner*, 229 F.2d 197 (5th Cir. 1956), 48 A.F.T.R. 859, 56-1 U.S.T.C. 54,470. However, it has recently been held in *INDOPCO, Inc. v. Commissioner*, 112 S. Ct. 1039 (1992), that legal expenses incurred by a target corporation in a friendly takeover were nondeductible capital expenditures.

   a. Request the lease file on each property.

   b. Review the lease and determine what tracts make up the lease and what types of interest were owned on each lease.

   c. Obtain from the taxpayer a map or plat that outlines the tracts that make up the property as it was used for claiming deductions on the tax return.

   d. Compare the taxpayer's definition to the IRS definition of property.

      1) Each different type of interest (working interest, royalty interest, etc.) is treated as a separate property.

2) The tracts or parcels of land must be contiguous (that is having a common side) and acquired from the same person on the same day.

3) Separate oil and gas deposits on each tract will be treated as one property, unless an election is made to treat them as separate properties. To qualify for separate property treatment, the taxpayer must account for the production from each deposit separately.

e. If an incorrect definition was used by the taxpayer, determine whether a clear and convincing basis exists to make the change.

1) If there is not a clear and convincing basis, the property definition will be accepted as established by the taxpayer pursuant to Rev. Proc. 64-23, 1964-1 (Part 1) C.B. 689.

2) If a clear and convincing basis exists occurred, correct the deduction claimed using the correct property definition. Increase the sample size to correct the property definition on any properties that would cause a material distortion of the tax deduction in question.

## AREAS TYPICAL OF AN OIL AND GAS ENTITY

### Gross Income

Entities in the oil and gas industry receive gross income from various sources. Below is a discussion of the various sources and suggested audit techniques to use when performing an income probe.

#### Oil and Gas Sales

When a well becomes productive, the operator of the well enters into a contract to sell the oil and gas, and a division order is created. The division order describes the economic interest, the owners of a property and the types of interest owned. (Exhibit 1-3 in Chapter 1 provides an example of a division order.) The division order accounts for 100 percent of the revenue ownership of the property. The purchaser uses the division order as the basis for paying revenues to the economic interest owners after paying the applicable severance taxes. The interests in the division order are stated in decimals. The division order may direct the purchaser to pay all of the interest holders directly, but usually it directs the purchaser to pay only the royalty owners directly and remit the receipts payable to the working interest holders to the operator. Purchasers of gas usually will remit 100 percent of the proceeds, less severance taxes, to the operator. The operator prefers to distribute the receipts to the working interest holders ensuring that other working interest owners pay their share of the well operation costs. The operator's payments to the other working interest holders are also based on the division order. Secure a copy of the division order and lease to compare the ownership percentages designated to the taxpayer with the percentage interest used to calculate the amount actually paid per the remittance slip.

Gross revenue from oil sales is determined by multiplying the barrels of oil delivered by the price per barrel of the particular grade of oil. The price of the oil may be the posted field price (price published and circulated between buyers and sellers in a particular field) or a spot price (short term negotiated price between buyer and seller). The oil produced from a well usually is held in a tank battery waiting for sale. When enough oil is accumulated, it is sold. It can be transported from the property by truck or pipeline. A run ticket is prepared at the point of transfer which records the gravity, temperature, impurities, and quantity of oil delivered. The amount of payment for the oil is based upon information contained in the run ticket. It is a reliable third party source document for verifying the volume of oil leaving the property. (A sample of a run ticket can be obtained from the Council of Petroleum Accountants Societies (COPAS), Arlington, Texas.)

Gross revenue from gas sales is determined by multiplying the cubic feet sold, according to the gas settlement statement, by the contract price. Natural gas is gathered through a pipeline system; it is not stored on the leased property prior to sale. Meters are put on the line to measure the amount of gas removed from a well or property. Gas is measured in cubic feet (CF) and is usually stated in MCF (thousands of cubic feet) or MMCF (millions of cubic feet).

Oil and gas from the lease are sometimes used on the property for lease operations (for example, oil may be spread on lease roads, oil and gas may be burned as boiler or generator fuel, or gas may be used for gas injection or lift). If the oil or gas is used for lease operations, it should not be included in gross income. If it is used on an adjacent lease or used for the lessor's personal use, then it should be included in the gross income of the property.

## Disappearance of a Particular Property

Examiners should compare the royalties reported by property for the current year with the prior and subsequent years. If they are not clearly identifiable on the return, copies of the depletion schedules should be requested. If a particular property disappears, or its income is reduced substantially, the taxpayer might have assigned his or her interest to a bank or third party as payment on a loan. Question the taxpayer about this and inspect new loan agreements; one can see how the repayment is structured. If production from a well is substantially reduced there may be correspondence between the operator and the royalty owner, which would explain the reduction.

## Working Interest Owner

Below are suggested audit techniques with regard to conducting an income probe on a "working interest owner."

1. Compare the properties per the detailed depletion schedules for the current year with the prior and subsequent years. Look for properties that:

    a. Continue to operate at a loss and no drilling or development is being done;

    b. Report income out of line with the expenses being claimed;

    c. Disappear from one year to the next, but no sale of the property is reported; and/or

    d. Incur large amounts of IDC but just before production the property is transferred to a third party or other family member.

2. In items 1. a, b, or c above, the taxpayer may be paying expenses of another interest owner or may have assigned a portion of the revenue interest to a third party for payment on a loan, etc. if questions arise under these items above, a reallocation of income and expenses under IRC section 482 should be considered. The following additional audit steps are recommended:

    a. Inspect the division order to determine the interest the taxpayer should receive. Compare this to the joint interest billings or remit slips. The interest that the taxpayer actually received should be reconciled to the interest reported.

    b. Inspect the lease agreement and amendments, if any, to determine the taxpayer's interest in the expenses. Compare this interest to the amount allocated on the joint interest billings and the amount claimed as a deduction on the return.

    c. Inspect the lease file to determine if there is any special problem with the property. There may be letters, or other correspondence, detailing problems on the property which would confirm any explanations made by the taxpayer.

    d. Obtain Securities and Exchange Commission's Form 10-K, if required to be filed. Form 10-K should disclose production payments and their nature.

    e. Inquire if a joint interest audit has been performed. If so, request results of the audit.

**<u>Lease Bonus</u>**

A bonus is paid for the execution of an oil and gas lease and is regarded as ordinary income to the lessor. It is usually computed on a per-acre basis. Inspect a copy of the lease agreement to determine the terms of the payments. If the lease agreement specifies that certain annual payments are to be made for a fixed number of years regardless of production, they are not recouped from future production. It is not important to establish that the payments were in fact a lease bonus. Prior to the Tax Reform Act of 1986, there was a question as to whether percentage depletion was allowable on lease bonuses. IRC section 613A(d)(5), as amended by the Tax Reform Act of 1986, clarified this controversy. The amendment provides that bonuses, advance royalties and similar items received or accrued after August 16, 1986, in taxable years ending after that date are not eligible for percentage depletion.

If the lessee is unable to avoid such payments by production or by terminating the lease, then the annual payments are regarded as an installment lease bonus. Payments received from an obligation that is not salable or freely transferable are income in the years the payments are received. However, if the rights to the bonus payments are freely transferable and readily salable, the total amount of the lease bonus is includible in income at the time the lease is executed even though the bonus is payable in installments. (Rev. Rul. 68-606, 1968-2 C.B. 42.)

Examining officers should inspect a copy of the check or checks received to verify the amount of the lease bonus payment. Reconcile the checks to the lease agreement.

## Delay Rentals

Delay rentals are amounts paid to the lessor for the privilege of deferring the commencement of a well on the lease. Delay rentals are reportable by the lessor as ordinary income. Since they are in the nature of rent, the payments for delay rentals are not subject to depletion. Inspect a copy of the lease agreement. The stated amount reflected in the lease should be compared to the amount received by the taxpayer. If it is different, ask the taxpayer why the amounts do not agree. If a smaller amount was paid, an amendment to the lease was probably made to keep the lease in force. Secure a copy of the amendment and inspect it.

For discussion of the capitalization of delay rentals, see Chapter 2.

## Royalty Income

A royalty interest entitles the owner to a specific fraction (in kind or in value) of the total production of oil and gas free of development and operating expenses. The lease agreement specifies the royalty retained by the landowner. Examiners should also inspect the check stubs and remittance slips to verify the amount of royalty received. Royalty income is ordinary income to the lessor.

## Advance Royalties

Advance royalties result from lease provisions that require the operating interest owner to pay a specified royalty regardless of whether any oil or gas is extracted during the period. The specified royalty is a fixed amount or an amount based on royalties due at a specified production level. Advance royalties are reportable as ordinary income.

## Minimum Royalties

Advanced royalties that result from a minimum royalty provision may, at the option of the payor, be deducted in the year paid or accrued. A minimum royalty provision requires that a substantially uniform amount of royalties be paid at least annually, either over the life of the lease or for a period of at least 20 years in the absence of mineral production requiring payment of aggregate royalties in a greater amount. For leases entered into prior to October 29, 1976, the option to deduct in the year paid or accrued was available for all advanced royalties. The option, however, is a one time election for the taxpayer. Once it is chosen, the election cannot be changed.

## Shut in Royalties

Most lease documents provide for payments to be made to the royalty owners when a well is shut in. A well is "shut in" when it is turned off because of lack of market or marketing facilities. Shut in royalties are paid to the lessor when the well, which is capable of producing in commercial quantities, is shut in. The lessee is entitled to deduct the shut in royalty payment and the lessor must take the payment into income.

## Production Payments

A production payment is a right to oil, gas, or other minerals in place that entitles its owner to a specified fraction of production until a specified amount of money or minerals has been received. For example, a typical production payment might require that 80 percent of production be paid to the holder until $50,000 plus 11 percent interest is received. A production payment is payable only out of the working interests' share of production.

There are two basic types of production payments. The first is a retained production payment. This is created when an owner of an interest in a mineral property assigns the interest and retains a production payment. The payment is payable out of future production from the property interest assigned. The other is a carved out production payment. It is created when an owner of any interest in a mineral property assigns a production payment to another person but retains the interest in the property from which the production payment is assigned.

Generally, a production payment is treated as a mortgage loan on the property and does not qualify as an economic interest in the mineral property. There is an exception where the consideration given for the production payment is pledged for development of the property, or if the production payment is retained upon the lease of the mineral property. In such situations, the payment will qualify as an economic interest and the payments made to the holder pursuant to the production payment agreement is treated as ordinary income (IRC section 636(c)). In some cases, the transaction should be treated as a sale of an overriding royalty interest. As an example, even when the production payment is pledged for exploration and development of the property, if the lease is undeveloped and mineral reserves have not been established and proven in sufficient quantities to generate enough income to retire the production payment (including interest) prior to the time that the lease is abandoned, the payment is not classified as either a loan or as a production payment pledged for development. Treas. Reg. section 1.636-3 requires that the life of the production payment must be shorter than the life of the property. Therefore, for an unexplored (wildcat) property, if no minerals are discovered or the reserves are in such small quantities that they will never pay off the production payment, the production payment's life will exist until the lease is abandoned. Once the lease is abandoned the transaction must be classified by the payor as a purchase of an overriding royalty interest, capitalized by the payor and treated as capital gain income by the payee.

The burden of proof is on the taxpayer that the production payment will be retired prior to the time the lease is abandoned. Before a producing well has been drilled on the lease, proof is almost impossible.

## Damages

When a taxpayer drills a well, the surface area of the land can be damaged. The owner of the surface rights is entitled to reimbursement for damages. The contract and/or supporting documents should be inspected to determine what type of damage payment is being made. The amount representing compensatory damages due to loss of profit is taxable as ordinary income. For example, payments made specifically for crop damage are taxable as ordinary income to the recipient. The amount representing damages for destruction of business and goodwill is nontaxable to the extent it does not exceed cost or other unrecoverable basis, and it is taxable as IRC section 1231 gain where there is no recoverable basis or the recoverable basis is exceeded. (Rev. Rul. 53-271, 1953-2 C.B. 36; modified by Rev. Rul. 83-49, 1983-1 C.B. 191)

Amounts paid for expected damages, but where no damage was done, do not qualify for treatment as return of capital. It was held in *Gilbertz v. United States*, 808 F.2d 1374 (10th Cir. 1987), rev'g 574 F. Supp. 177 (D Wyo. 1984), that payments for anticipated damages are ordinary income and not return of capital.

## Shooting Rights

An operator may not want to incur the costs of entering into a lease on a property. In most cases, the taxpayer is attempting to avoid the high costs of lease bonuses. Accordingly, the operator will enter into a contract with the landowner to pay a smaller amount under a contract which gives the operator the right to enter onto the property and conduct exploration activities, but grants no drilling or production rights.

These limited rights are referred to as shooting rights.  The amounts received by the landowner in exchange for the shooting rights are ordinary income.  Examiners should inspect the "shooting rights contract" and compare the sum stated to what was reported.

Figure 3-1 is a chart illustrating the tax treatment of payments under an oil and gas lease.

**Tax Treatment of Payments Under an Oil and Gas Lease**

| Type | Payor or Lessee | Payee or Lessor |
|---|---|---|
| BONUS<br><br>Basic consideration for executing lease. | Capitalize<br><br>Treas. Reg. section 1.612-3(a)(3) | Ordinary Income<br><br>Percentage deletion allowed to August 17, 1986. Only cost depl. after August 17, 1986. Treas. Reg. 1.612-3(a)(1) |
| INSTALLMENT BONUS<br><br>Also consideration for granting a lease; advance payment for oil; each installment is usually larger than normal delay rental. | Capitalize | Ordinary Income<br><br>Rev. Rul. 68-606, total amount includible at time of signing lease if right to income is transferable. Gener-ally, this treatment is the same as for lease bonus. |
| DELAY RENTAL<br><br>Pure rent; a payment to defer development rather than a payment for oil. | Before capitalize Delay Rental consult PIP for the current position under IRC section 263A. | Ordinary Income<br><br>No depletion.<br>Treas. Reg. section 1.612-3(C)(2) |
| ROYALTY<br><br>Payment for oil or gas. | Deductible<br><br>See Rev. Rul. 72-165 when ad valorem taxes are involved. | Ordinary Income<br><br>Subject to depletion (percentage or cost); percentage depletion is allowed if payee qualifies under IRC section 613A. |
| ADVANCE ROYALTY<br><br>Royalty payment made before production of minerals. | Deductible<br><br>See Rev. Rul. 72-165 when ad valorem taxes are involved. | Ordinary Income<br><br>Subject to cost depletion in year payments are made. Percentage depletion allowed until August 17, 1986. |
| ADVANCED MINIMUM ROYALTY<br><br>Minimum royalty payment required by contract terms. | Deductible<br><br>At option of payor: (1) In year paid or accrued or (2) When oil or gas is sold or recovered. Treas. Reg. section 1.612-3(b)(3) | Ordinary Income<br><br>Subject to cost depletion. Allowed percentage depletion until August 17, 1986. |

**Tax Treatment of Payments Under an Oil and Gas Lease (continued)**

| Type | Payor or Lessee | Payee or Lessor |
|---|---|---|
| PRODUCTION PAYMENTS | | |
| RETAINED (SALES TRANSACTION)<br>Not an economic interest. Is treated as a mortgage. | Repayment of principal and interest expense. | Repayment of principal and interest income. |
| RETAINED (LEASING TRANSACTION)<br>An economic interest. | Capitalize, bonus paid in installments. Treas. Reg. section 1.636-2(a). | Ordinary income. Subject to depletion (percentage or cost). Treas. Reg. section 1.636-2(b). |
| CARVED OUT AND SOLD: NOT AN ECONOMIC INTEREST<br>Simply a loan. | Repayment of principal and interest expense. | Repayment of principal and interest income. |
| CARVED OUT AND SOLD: AN ECONOMIC INTEREST<br>that is, pledged for development of property. | Capitalize as installment lease bonus. | Ordinary, depletable income. |
| DAMAGES | | |
| BUSINESS AND GOODWILL<br>that is, surface damages. | If acquired or leased, capitalize as G & G costs.<br>If not acquired or leased, expense. | Return of capital to the extent of basis of the property.<br>Amounts in excess of basis are IRC section 1231 gain. |
| LOSS OF PROFIT<br>that is, crop damages. | If acquired or leased, capitalize as G & G costs.<br>If not acquired or leased, expense. | Ordinary Income. |
| ANTICIPATED DAMAGES BUT NONE WAS DONE<br>Amount paid based on the anticipation that damages would occur. | If acquired or leased, capitalize as G & G costs.<br>If not acquired or leased, expense. | Ordinary Income. |

**Tax Treatment of Payments Under an Oil and Gas Lease (continued)**

| Type | Payor or Lessee | Payee or Lessor |
|---|---|---|
| SHOOTING RIGHTS | | |
| PURE CONTRACT | Capitalized as G & G. | Ordinary income. |
| CONTRACT WITH OPTION TO ACQUIRE OR LEASE | If acquired or leased, treat as lease bonus. | Ordinary income. Cost depletion allowed only after August 17, 1986. |
| | If not acquired or leased, expense in year option expires. | Ordinary income. |

## UNIFORM CAPITALIZATION RULES -- IRC SECTION 263A

IRC section 263A is the written expression of the U.S. Congress' intent to apply a uniform set of capitalization rules to all costs incurred in manufacturing or constructing property or in purchasing and holding property for resale. Costs relating to the production of real or tangible personal property and the purchasing and holding of property for resale are subject to uniform capitalization (UNICAP) rules.

### Produced Property

The industry has recognized the self-constructed asset as tangible or surface well equipment. The asset construction rules in IRC section 263A generally apply to construction of assets used, or to be used, in a trade or business. The rules also apply to assets described in IRC section 1231. However, controversy surrounds the leasehold mineral interests. The term "produce," as described in IRC section 263A(g), includes construct, build, install, manufacture, develop, or improve. Historically, IRC section 341(b) also contains this same language: "manufacture, construction, or production of property."

Rev. Rul. 57-346, 1957-2 C.B. 236, holds, under IRC section 341(b)(1), that a corporation engaged in acquisition and development of oil properties is considered to be involved in the construction or development activities that increased the value of the properties. Rev. Rul. 68-226, 1968-1 C.B. 362, defines an oil and gas leasehold as an interest in real property. These rulings support the Service's position that historically a mineral interest is real property. Thus, a taxpayer who acquires and develops oil or gas properties is engaged in a developmental activity within the meaning of IRC section 263A. Produced property could include G & G data, acquiring and developing the leasehold mineral interest, constructing tangible and surface well equipment, and carrying oil and gas inventory (barrels of oil and MCF of gas). It does not include acquiring undeveloped leases.

**Predevelopment Expenses**

The discussion that follows will detail some areas where IRC section 263A may affect oil and gas operations. Many oil operators maintain inventories of undrilled leases for resale to others or transfer to limited partnerships. The rules relating to inventories should be applied in this area. Exploration, drilling, and development activities could be construed as activities which improve property. The Tax Court has held in various decisions, including *Sun Company, Inc. v. Commissioner*, 74 T.C. 1481 (1980), *aff'd*, 677 F.2d 294 (3rd Cir. 1982), that exploration and developmental drilling could not be distinguished for IDC purposes. However, it has been held that exploration is considered a separate activity from development and production.

(*Shell Oil Co. v. Commissioner*, 89 T.C. 371 (1987), *rev'd*, 952 F.2d 885 (5th Cir. 1992)). IDC is specifically exempt from the boundaries of IRC section 263A, but the rules may apply to production of oil if an inventory of oil is on hand at the end of the year. Examiners should take caution in this area as most taxpayers have little or no inventory on hand at the end of the tax year. Geological and geophysical activities should be allocated an appropriate share of indirect costs. Treas. Reg. section 1.263A-1(b) lists costs which are excepted from the UNICAP rules.

IRC section 263A requires costs that have been traditionally capitalized to continue to be capitalized. Also, there are other costs that are known as additional IRC section 263A costs. These include direct costs, indirect costs, mixed service costs, and certain interest costs. Each of these costs are discussed below.

1. Direct costs are labor and material that are directly related to a property. Direct materials are those that are a part of the property or consumed in the activity. Direct labor costs are labor costs including fringe benefits which are associated with the property or activity. These costs have traditionally been capitalized.

2. Indirect costs are all other costs that directly benefit production, or are incurred because of the production activity. If they benefit more than one activity, they need to be allocated on a reasonable basis to the activities involved. Treas. Reg. section 1.263A-1(e)(3)(ii) has an extensive list of indirect costs that must be capitalized. If there is a question as to whether an indirect cost should be allocated, refer to Treas. Reg. section 1.263A-1(e)(3)(iii). This section of the regulations discusses additional indirect costs that are not required to be allocated.

3. Mixed service costs are costs of administrative, service, or support departments or activities which benefit more than one activity. These costs must be allocated, on a reasonable basis, to the activities which benefitted from them.

4. Interest costs incurred to finance the production of property must be capitalized, if the property produced is:

    a. Real property, or

    b. Personal property with a MACRS life of 20 years or more, or

    c. Personal property with an estimated production .now, period of more than 2 years, or

    d. Personal property with an estimated production period of more than one year and the estimated cost of production exceeds $1 million.

## INTEREST CAPITALIZATION

Under the interest capitalization rules, the interest to be capitalized is the interest that would have been avoided if the production expenditures relating to the property or activity had not been made, and the funds were used to repay the debts of the taxpayer. Debt which can be traced specifically to an activity is allocated to that activity. If the production expenditures relating to an activity exceed the debt traced to the activity, other debt must be allocated to the activity.

Interest on debt allocable to leasehold costs should be capitalized during the production period because mineral leases are real property. It has not been determined whether the entire leasehold cost is included in the base if only a portion of the property is under construction. For further guidance in this aspect of the UNICAP rules, refer to the final regulations under IRC section 263A(f) published in December 1994.

In the case of onshore activities, the production period for a unit begins on the first date physical site preparation activities are undertaken with respect to that unit (for example, building an access road, leveling a site for a drilling rig, or excavating a mud pit). In the case of offshore activities, the production period for a unit begins on the first date physical site preparation activities (for example, drilling to drive the piles) other than activities undertaken with respect to expendable wells, are undertaken. An expendable well is a well drilled solely to determine the location and delineation of hydrocarbon deposits. The production period ends when the well is ready to produce.

## ALLOCATION OF INDIRECT COSTS

The Code and Treasury Regulations do not specify how the indirect costs are to be allocated. But the regulations provide several "simplified" methods that are available to the taxpayer. The indirect costs should be matched with the activities that benefit from the incurred costs. The taxpayer should use the same method for allocating overhead. The allocation method should be used consistently and for all federal tax purposes.

Taxpayers in the petroleum industry use different accounting methods to allocate indirect costs. The accounting methods fall under two categories: facts and circumstances methods and simplified methods. Under the facts and circumstances concept, taxpayers use the specific identification method, burden rate, or standard cost method, and any other reasonable method of allocation. The simplified service cost method and simplified production method is used in allocating indirect costs under the simplified concept.

The final regulations added an exception for certain producers, who use the simplified production method, with total indirect costs of $200,000 or less. Treas. Reg. section 1.263A-1(b)(12) and section 1.263A-2(b)(3)(iv) set out the exception. The "small manufacturer" exception applies when a producer uses the simplified production method and incurs $200,000 or less of total indirect costs in a taxable year; the additional IRC section 263A costs allocable to eligible property remaining on hand at the close of the taxable year are deemed to be zero.

## CONCLUSION

In conclusion, specific items to which IRC section 263A may apply are G & G activities, leasehold costs, tangible well equipment, surface production equipment, and inventory. Intangible drilling costs are excluded from section 263A, but overhead may still be allocated.

## AUDITING TECHNIQUES

Notice 88-99, Treas. Reg. section 1.263A-0 through 1.263A-3, and Treas. Reg. section 1.263A(f)-O through 1.263A(f)-9 are the most useful tools for conducting an examination with regard to items relating to IRC section 263A.

In addition to the notice and regulation sections set out above, some suggested audit techniques are set out below that are useful in conducting an examination involving the UNICAP rules.

1. Did the taxpayer take IRC section 263A into account when they prepared their tax return? If it was not taken into account, devise an allocation method based on the rules listed in the regulations.

2. Determine if the taxpayer correctly handled the production period. If not, you must determine the correct production period.

3. Determine if the taxpayer meets the definition of a qualified "small manufacturer." One is a "small manufacturer" if it uses the simplified production method and,

during its tax year, incurs total indirect costs of $200,000 or less. If the total indirect costs meet this criteria, the additional IRC section 263A costs may be treated as zero.

4. If the taxpayer is a reseller, determine if the average gross receipts during the last 3-year period is $10 million or more. If this "de minimis rule" is satisfied, the taxpayer will be exempt from IRC section 263A.

5. If the taxpayer has an inventory of oil on hand at the end of the year, ensure that all items are correctly capitalized.

6. If no exceptions apply and the taxpayer maintains an inventory of undrilled leases for resale to others or for transfer to limited partnerships, make sure that IRC section 263A was correctly applied.

7. Determine if the taxpayer was "drilling" any wells in the year of audit. Inspect other sources such as annual reports, general ledger additions, or minutes to determine other self construction projects.

8. If the taxpayer has interest expense related to their production of oil and gas, verify that the correct amount of interest was capitalized.

    a. Determine whether the taxpayer has used the proper interest capitalization period on leasehold development.

    b. Determine the proper application of the now repealed IRC section 189. Uniform capitalization rules apply to interest paid or incurred after December 31, 1986, on debt incurred before December 31, 1986, to the extent IRC section 189 applied before its repeal. A leasehold was real property covered under section 189 for interest capitalization purposes.

    c. Obtain FASB 34 calculations for interest capitalization to ascertain the average effective interest capitalization period. Identify construction projects subject to interest capitalization.

## LEASEHOLD COST

The costs associated with acquiring or retaining a lease are classified as leasehold costs. These costs are considered capital expenditures. Many taxpayers will misclassify the costs associated with obtaining a lease to various expense accounts and only capitalize the lease bonus. Test lease operating cost, legal and accounting, office supplies, travel and entertainment, miscellaneous, and similar accounts for acquisition costs that may have been deducted as current expenses. Examining officers should refer to *INDOPCO, Inc. v. Commissioner*, 112 S. Ct. 1039 (1992), with regard to legal expenses. It was held in this case that legal expenses were nondeductible capital expenditures.

In some cases, an advance royalty is, in fact, a disguised lease bonus. The Service utilizes *Anderson v. Helvering,* 310 U.S. 404 (1940), 24 A.F.T.R. 867, 40-1 U.S.T.C. 553, for treating a payment as a lease bonus subject to capitalization as lease acquisition costs. This classification is made if the lease instrument provides for an advance royalty to be paid to the mineral and royalty owner, regardless of whether production of the mineral ever occurs, and there is no refund provision.

Leasehold costs include commissions or finders fees, abstracting costs, attorney's fees for title opinions, drafting deeds, and instruments of conveyance. If the property purchased already has production, there may be engineering costs involved in the appraisal of the equipment and a study of the oil and gas reserves. Some companies have sufficient leasing activity to warrant the services of a landman, a person experienced in mineral leasing activities. The landman's salary/contract labor should be a part of the capitalized leasehold cost, if they can be attributed to the acquisition of a particular mineral lease. The same would be true with respect to a leasing department. Not all of the efforts of a landman or a leasing department will result in the acquisition of a lease. In such instances, costs should be allocated between the successful and unsuccessful attempts of acquiring leases on some reasonable basis, if an adjustment would be material.

Scan the nonproducing lease account in the asset section of the ledger to determine the number and names of leases acquired during the year. This is done to become familiar with the nonproducing leases and assist in determining whether capital costs associated with those properties have been incorrectly expensed.

If a lease expires, a taxpayer is allowed to write off the capitalized cost of the lease, even if a new lease is later obtained on the same property. A loss is not allowed if a new lease is obtained covering the property (known as a top lease) prior to the expiration of a lease. The cost of the old and new lease are capitalized to the same property. Taxpayers sometimes denote a renewal of a lease by adding "R" immediately after the identification number of the property. Once renewal leases are identified, examiners should check to ensure that the costs of renewal are capitalized to the leaseholds and the original leasehold costs have not been written off.

Below are some examples of leasehold costs that should be capitalized.

1. Research of lease location by engineer, geologist, etc. for purposes other than locating a well.

2. G & G expenditures leading to acquisition or retention of an oil and gas property.

3. Expenses in connection with leasing the property from a landowner.

4. Legal costs of securing a lease and clearing the title.

5. Legal fees incurred to obtain access to the property and to obtain easements, etc.

6. Lease bonus paid to the landowner or other owner.

7. Purchase price of an existing lease.

8. Core-hole wells drilled to obtain geological data.

9. Seismic work to determine the size of the reservoir or reserve.

10. Legal fees incurred in drafting contracts.

11. Travel expenses incurred in acquiring leases.

12. Salaries of land department personnel in acquiring leases.

13. Equalization payments paid in furtherance of a unitization, when paid in connection with prior IDC.

14. Bottom-hole contribution when paid to obtain information which enhances the value of the property.

15. IDC, if there is no election to expense.

16. Delay rentals, when election is made to capitalize.

## GEOLOGICAL AND GEOPHYSICAL (G & G) COSTS

An operator planning to lease property does not do so without acquiring some information about the prospect. Initial information is obtained through the use of G & G exploration methods. Geological methods consist of the search of a surface for indications of hydrocarbons, geological mapping, topographical mapping, aerial photography, and radiation surveying, to name a few. When enough information is obtained to show favorable conditions for oil or gas, the lease is acquired and additional exploration is performed to further define the prospect.

The exploration costs that lead to the acquisition or retention of mineral properties must be capitalized as part of the cost of the properties. You will usually encounter this issue when auditing an operator. The operator may use either in-house or outside engineers and geologists to lease and develop unproven properties or to decide to purchase productive properties. Most operators will capitalize the costs that were paid to engineers and geologists outside the company, but they will not capitalize a portion of the salaries and overhead allocable to in-house personnel who perform the same types of services.

The amount of G & G costs to be capitalized by a taxpayer depends upon the taxpayer's operations. In some cases, taxpayers will limit their business activities to purchasing properties which are already producing. The seller already has incurred the

G & G costs necessary to drill a successful well which is reflected in a higher purchase price. The purchase price is capitalized to leasehold costs along with additional G & G or other investigating costs which are incurred in evaluating the property to be purchased.

At the opposite end of the business spectrum, large corporate taxpayers may identify and develop their own prospects completely through the use of their own in-house specialists. The taxpayer will usually identify a project area and conduct a reconnaissance type survey. Based on this survey, smaller areas of interest (noncontiguous project portions which warrant detailed G & G costs) will be identified within the project area. The costs associated with these surveys must be allocated equally among the areas of interest, even if the acreage contained in the areas of interest are different. For example, a taxpayer spends $9,000 and identifies three areas of interest in a project area. One-third of the $9,000 or $3,000 must be capitalized to each area of interest even if one area of interest is substantially bigger than the other two. The costs assigned to an area of interest can only be written off when the area of interest is abandoned.

Often, a taxpayer will claim that there are more areas of interest than really exist. This claim is made so the taxpayer can assign a portion of the survey costs to the area and then quickly write the costs off through abandonment. If this appears to be the case, the help of an Engineer may be needed in identifying an area of interest.

By definition, an area of interest is an identified area where more intense G & G exploration methods will be employed. If no additional costs are incurred on an alleged area of interest after the initial surveys, then the area was never an area of interest. The related costs should be reallocated to other legitimate areas of interest. After initial G & G work, decisions are made to acquire leases, investigate further, or abandon the costs incurred to date. Sometimes several years will pass before the taxpayer will make the decision to acquire a lease. Examiners need to determine the proper taxable period in which the final or controlling decision was made. Also, if acreage is acquired with the lease, the costs accumulated are allocated based on the net acreage acquired.

Using the example set out above, where $3,000 of G & G costs was capitalized to a project area, suppose that the taxpayer leases a 25 percent working interest in 40 acres and a 50 percent working interest in 10 acres all in the first project area. The $3,000 of G & G costs will now have to be allocated among the leased acreage based on the following formula:

| | **Gross Acres** | **Equivalent Working Interest** | **Net Acres** | **Allocation Fraction** | **Allocation** |
|---|---|---|---|---|---|
| Lease #1 | 40 | 25% | 10 | 10/15 | $2,000 |
| Lease #2 | 10 | 50% | 5 | 5/15 | $1,000 |
| Totals | | | 15 | | |

For the purpose of converting a royalty interest to an equivalent working interest, in the example set out above, the royalty ownership percentage should be doubled.

When dealing with an oil and gas operation which conducts a significant amount of its own exploration in-house, the taxpayer should also be required to capitalize a portion of its corporate overhead to its exploration activities using reasonable cost accounting methods, in addition to the direct costs.

If assistance is required, the services of an Engineer should be requested. Even if an engineer assists with the examination, certain information can be obtained early in the audit. Set out below are suggested audit techniques examiners can utilize when conducting an investigation of G & G costs.

1. Determine whether the taxpayer develops its own properties or acquires already producing properties.

2. If the property is already productive, someone has spent time analyzing data about its potential productivity. The cost of that person's time should be determined and capitalized to the leasehold cost along with any related overhead.

   This should be done for any properties that were purchased during the year or still being investigated for purchase at year-end.

   a. Request the taxpayer to provide you with a list of the properties acquired during the current year and/or properties they were trying to acquire at year-end.

   b. Determine the persons involved in providing and analyzing the information and making the purchasing decisions of the lease (that is, geologist and engineers who interpret or produce data, etc.).

   c. Determine these persons' salaries and the associated overhead allocable to their salaries, if in-house personnel were used. For detail on this, see "Overhead Allocation" later in this chapter.

   d. Verify the cost incurred to shoot the G & G. Ensure that direct and indirect costs are properly included in the G & G amount for each respective project.

   e. Capitalize these costs to leasehold cost.

3. If the property is an unproductive property, the taxpayer may have started with a project area, an area of interest, or a lease. Determine at what point the taxpayer began incurring costs. Identify the costs involved and whether they were handled properly.

   a. Have the taxpayer identify the project area, areas of interest, and leases acquired or to be acquired, by name and on a map or plat. An engineer may be needed because some taxpayers have a problem identifying too many areas of interest in a project area.

b. Identify the reconnaissance survey cost on a project area and determine if it was allocated equally among the areas of interest that have been delineated. If none are acquired, the costs can be deducted under IRC section 165.

c. Identify the detailed survey cost performed on the areas of interest. Determine if they were allocated based on a net acreage basis to the lease(s) obtained. If leases were acquired adjacent to the area of interest due to the reconnaissance survey and detailed survey, the allocated costs of the reconnaissance survey and the cost of the detail survey are capitalized to the lease(s) acquired. If no lease is acquired in the entire area of interest, then the cost is deductible under IRC section 165.

d. Identify the geologists and engineers who worked on each project area, area of interest, and/or lease. Determine what portion of their salaries should be capitalized to the leases acquired. Interview the taxpayer and the geologists/engineers. Have them assist you in arriving at the amounts to capitalize. If they are uncooperative, you may need the help of an IRS Engineer.

e. Identify the amount and the items in overhead that should be allocated based on a "reasonable method" for allocation. For detail on this, see "Overhead Allocation" later in this chapter.

f. The amounts capitalized are added to the basis of the leasehold costs of acquired leases. If the property was productive in the year of the examination, an additional cost depletion deduction may be required if cost depletion would be greater than percentage depletion.

4. Remember that not all project areas or properties that the taxpayer looked at will be pursued. Determine if the taxpayer will be allowed to write off the costs incurred for the geologist salaries, the reconnaissance survey and detailed surveys as an abandonment.

Rev. Rul. 77-188, 1977-1 C.B. 76 and Rev. Rul. 83-105, 1983-2 C.B. 51, offer more insight to the tax treatment of G & G costs. *Louisiana Land and Exploration Co. v. Commissioner*, 7 T.C. 507 (1946), *aff'd* on other issues, 161 F.2d 842 (5th Cir. 1947), gives further guidance in this area.

## ABANDONMENT COST

When a property is determined to be unproductive, the lessee will want to write off the costs associated with the unproductive property. The amount of the deduction for abandonment costs depends upon the stage of development of the property. The timing of the deduction for abandonment is based on certain identifiable events.

For the lessee, losses from unproductive properties may be deducted in the following situations:

1. Abandonment of Unproved Property: A lessee will incur G & G costs, along with other costs of developing a project area and areas of interest, long before any leases are entered into. Many times a lease is not acquired or the project is put aside for a while to wait for the "right time" for further development. Often, a taxpayer will use this hiatus in activity to claim an abandonment loss, even though the taxpayer has no present intent to abandon the property. If no reserves are found in a project area or an area of interest, the costs associated with the area are allowed to be written off as an abandonment loss. Once reserves are determined to exist, Rev. Rul. 77-188 and Rev. Rul. 83-105 require that an "identifiable event" occur before a write off will be allowed. These rulings hold that an identifiable event would occur when one of the following exists:

   a. There is a lease sale that includes the area of interest involved and the entity is unsuccessful in obtaining a lease.

   b. There is an indication that the area of interest will not be included in a lease sale.

   c. There is an event that establishes that the area of interest is worthless.

   Rev. Rul. 83-105 suggests that where exploration is conducted offshore, or on Government interests onshore, the passage of 10 years without the areas having been included in a lease sale, or without an indication that the area will be so included, is considered to be an event warranting a deduction of related costs. For onshore interests, other than Government interests, the passage of 5 years is considered to be an identifiable event if no earlier identifiable event occurs.

2. Abandonment of Lease: An abandonment loss may be deducted in the year in which the property is deemed worthless. A property is deemed worthless if the title is abandoned through relinquishment. Title relinquishment is considered to be a closed and completed transaction, thereby proving worthlessness. Without the relinquishment of title, leasehold costs should not be written off. A copy of the lease should be secured to determine if it has been relinquished. The lease will have a primary-term clause and a delay-rental clause. (Exhibit 1-1 is an example of a mineral lease.) Delay rentals are paid to defer the drilling activity for designated periods of time within the primary term. Drilling cannot be deferred beyond the primary term by payment of delay rentals. The timely payment of delay rentals and timely drilling keeps the lease in effect. However, if delay rentals are not paid timely or drilling has not commenced within the primary term, then the taxpayer must forfeit the lease.

Another way a taxpayer may relinquish title to a lease is to execute a quit claim deed. A quit claim deed transfers the title to the mineral interest back to the lessor. Once the taxpayer relinquishes title to the lease, the taxpayer will be allowed an abandonment loss. The amount of the loss will be the adjusted basis of the leasehold costs and the costs associated with any unamortized IDC, if the taxpayer previously elected to capitalize IDC.

3. Abandonment of Lease and Well Equipment: When a reserve is depleted, the adjusted basis of lease and well equipment may be written off when the well(s) are abandoned, even when the lease is not abandoned. A plug and abandonment report may be filed with the appropriate state agency when a well is abandoned. (Exhibit 3-2 is an example of Form W-3, which is required by the State of Texas.) This report should be inspected to determine when the abandonment actually occurred. The examiner should determine what happened to the equipment after its removal from the lease, since it could have been transferred to another lease or a warehouse facility awaiting assignment to another lease. Any salvage value received for the lease and well equipment should reduce any loss claimed on the equipment.

4. Abandonment of Dry Hole Costs: When a well is determined to be a dry hole, the taxpayer is allowed to write off the IDC incurred as "dry hole costs." A separate election to expense dry hole costs is required if the taxpayer capitalizes IDC. By expensing IDC as dry hole costs, the taxpayer is not required to include these costs as an IDC tax preference item in computing alternative minimum tax. Thus, a determination must be made that the well never produced oil or gas. If the amount of the dry hole costs written off is material, examiners should request the plug and abandonment report to substantiate that the well was abandoned. Leasehold costs cannot be written off when a dry hole is drilled until title to the lease is relinquished.

## AUDIT TECHNIQUES

Abandonment losses can be very easy to verify. For example, if the well was plugged and the report was filed with the proper state agency, the report would support an allowance of a deduction for the abandonment loss. However, examiners need to ensure that the well was not reentered. In addition, it should be verified that the "entire property" under the definition of property was abandoned.

Below are suggested audit techniques that examiners can utilize in the examination of abandonment losses. The audit techniques are broken down into two categories: (1) Nonproductive properties where no leases have been executed. (2) Nonproductive properties where leases have been executed.

Nonproductive Properties (No Leases Executed):

1. Obtain a breakdown of the abandonment expense by amount and name.

2. Request a breakdown of the cost incurred on the properties.

3. Determine what the project area was, and what the areas of interest were.

    a. Obtain a name and description from the taxpayer for the project area and the areas of interest.

    b. Have the taxpayer show the boundaries of the project area and the areas of interest on a map or plat.

4. Determine if additional costs were expended on an area of interest after it was identified as such. If no additional costs were incurred, the area was probably not a true area of interest. If the amount is material, an engineer may be consulted.

5. If no reserves were determined in the whole project area, the costs associated with the project may be abandoned.

    a. Determine whether the amount expended applies only to the project area in question.

    b. Test the allocation of the costs to the area of interest.

        1) Costs that are not direct costs of an area of interest are allocated equally between areas of interest. Areas of disinterest in the project area should receive no allocation.

        2) Direct costs of an area of interest should be directly assigned to that area of interest.

6. If reserves were determined in a particular area of interest, but no lease was acquired, determine that no lease was acquired by the following:

    a. Question the taxpayer as to whether any leases were acquired in or adjacent to the area of interest.

    b. Scan subsequent year acquisitions to determine whether leases in this area of interest were acquired in a subsequent year.

7. Determine that an "identifiable event" has occurred allowing the write off of the costs incurred. An "identifiable event" occurs when one of the following criteria exists.

a. A lease sale that includes the area of interest involved and the taxpayer is unsuccessful in obtaining a lease;

b. An indication that the area of interest will not be included in a lease sale;

c. An event that establishes that the area of interest is worthless; or

d. There has been an elapsed time of 5 years for onshore properties, or 10 years for offshore or Government properties.

8. Verify the amount of the abandonment loss for the area of interest by testing the allocation of costs. Inspect records showing costs charged to the area of interest.

a. Costs that are not direct costs of an area of interest are allocated equally among the areas of interest. Areas of disinterest in the project area should receive no allocation.

b. Direct costs of an area of interest should be directly assigned to that area of interest.

<u>Nonproductive Properties (Executed Leases)</u>:

1. Obtain a list of the properties abandoned by the taxpayer.

2. Request the lease file on the abandoned properties.

a. Determine from the lease agreement if the primary term of the lease expired during the year under audit. (The primary term description of a lease would look something like "clause 2" per mineral lease sample, Part IV, Exhibit 1-1.)

1) If the lease has expired, the taxpayer has sustained a loss.

2) If the lease expired prior to the audit year, the loss would not be allowable in the year of examination. However, if the prior year's statute of limitations has not expired, the loss would be allowable in the year of expiration.

b. If the primary term is still in effect, determine if the taxpayer ceased to pay delay rentals on the lease in the year under audit.

1) Inspect the lease agreement, and determine when payments should have been made. Determine if payment was not made. (The delay rental description of a lease would look something like "clause 5" per mineral sample, Part IV, Exhibit 1-1.)

2) Inspect the delay rental record. The taxpayer will usually keep a delay rental record for each nonproductive lease. This record usually has the amount, date,

and to whom the delay rental was paid. If a payment was not made on the next due date, there may be a notation.

3) Inspect the lease file for any correspondence or notes about allowing the lease to lapse.

   a) If the delay rental date lapsed during the year under audit, the taxpayer has sustained a loss.

   b) If the delay rental lapsed prior to the audit year, the loss would not be allowed.

   c) If the delay rental was paid and in force during the audit year, a loss would not be allowed unless a quit claim deed was executed or the primary lease term lapsed without production.

C. Determine if a quit-claim deed was executed by the taxpayer.

1) Inspect the lease file and ask for the quit claim deed. Ensure the date it was executed is in the taxable year under examination.

2) If a quit claim deed was not executed in the audit year, the taxpayer will not be allowed an abandonment loss unless the primary term has lapsed without production or a delay rental was not paid in the audit year.

## LEASE OPERATING EXPENSE

Operating expenses are deductible in accordance with the taxpayer's method of accounting. Therefore, it is important to be able to distinguish and categorize the various expenditures that will be encountered in an oil and gas producer's return.

Examiners should be aware that there will be a tax impact for any material item misclassified as operating expense when in reality it is leasehold costs. In the oil and gas industry, operating expenses are commonly referred to as lease operating expense (LOE). It includes the cost of operating and maintaining producing leases. It also includes the cost of labor for operating and maintaining the equipment on the lease, repairs and supplies, utilities, automobile and truck expenses, taxes, insurance, and overhead expenses such as bookkeeping, billing costs, and correspondence.

Operating expenses of oil and gas leases will include direct and indirect expenses and depreciation. Operating costs on secondary and tertiary recovery projects are somewhat higher because of the added expense of injecting water, gas, etc., into the producing formation. The cost of the specialized equipment needed, such as pumps, tanks, boilers, high pressure wellhead equipment, etc., must be capitalized and recovered through depreciation. The cost of operating the equipment is LOE.

Two judicial decisions, rendered in the 1930's, addressed the issue of LOE. The following is the gist of the opinions with regard to LOE:

> "In the examination of lease operating expense, expenditures will be found for servicing the well, often called workover expenses, such as pulling rods, acidizing, fracturing, cleaning out, etc., all of which are operating expenses. Closely associated with these expenditures are others that have been held to be IDC, for example, the fracturing of the producing sand with nitroglycerine before being placed in production and cleaning out of the well. The deepening of an existing well is IDC."

(*P-M-K Petroleum Co. v. Commissioner*, 24 B.T.A. 360 (1931), rev'd, 66 F.2d 1009 (8th Cir. 1933), 12 A.F.T.R. 1335 and *Monrove Oil Co. v. Commissioner*, 28 B.T.A. 335 (1933), aff'd on another issue, 83 F.2d 417 (9th Cir. 1936), 17 A.F.T.R. 978, 36-1 U.S.T.C. 521.)

There is no simple way of distinguishing workover costs that are proper operating costs from those that are IDC. Inspection of invoices or AFEs will reveal deepening expenses. This will be obvious from an inspection of the invoices. Fracturing of the producing zone in a well before it has produced oil is a fact that will have to be determined from the production records or other sources of information that should be in the possession of the taxpayer.

Before spending a lot of time on this item, consider the tax impact. If the taxpayer has elected to expense IDC and there is no prospect for alternative minimum tax, there is no point in examining this area or attempting to distinguish IDC from operating costs.

The following are examples of lease operating expenses:

1. Cost of switcher or pumper to operate the wells.

2. Cost of minor repair of pumps, tanks, etc.

3. Grading existing roads.

4. Treat-o-lite and other materials and supplies consumed in operating the lease.

5. Pulling sucker rods, pump, and cleaning the well.

6. Utilities.

7. Taxes other than federal income taxes.

8. Depreciation of equipment used on the lease.

9. Rental of lease equipment.

10. Salaries for painting and cleaning on the lease.

11. Lease signs.

12. Salaries of other operating personnel: farm boss, engineer, etc.

13. Salt water disposal costs.

14. Rental payments to mineral owner when not based on production.

15. Allocable portion of overhead costs.

16. Qualified tertiary injection expenses.

Even though it was noted earlier that LOE was not a very productive issue, it is important to distinguish between LOE and IDC. Lease operating expenses make up the bulk of cost of goods sold on oil and gas properties. Although both, LOE and IDC, are fully deductible in the current period, only IDC is a tax preference item for alternative minimum tax.

## BAD DEBTS (JOINT INTEREST OWNERS)

This issue will be found when auditing an operator that has claimed bad debts in connection with joint interest billings. When taxpayers first become the operator of a property, they enter into an operating agreement with all the working interest owners. This is a standard agreement and gives both the working interest owner and the operator certain rights and recourse if the agreement is violated. One of the duties of the operator is to collect the joint interest payments from the working interest owners who have joined together to develop and operate the property under the operating agreement.

Sometimes a working interest owner will refuse to pay its share of the drilling or operating costs of a well or property. When this happens, the operator has certain steps to take to recoup its funds under the operating agreement. If the property is a producing property and the operator is receiving the disbursements from the purchaser to distribute to the working interest owners, the operator can offset the nonpaying working interest owner's share of distributions against the funds owed to the operator on that particular property. If a property is dry, minimally productive (that is, the income from the property does not cover the operating cost), or the purchaser pays the nonpaying working interest owner directly, the operator may sue the nonworking interest owner for breach of contract for nonpayment of its joint interest billings. The court may assign the interest of the nonpaying working interest owner to the operator if the property is productive, or it may file a judgment against the nonpaying working interest owner. Judgments are very hard to collect. If the property is productive, the court also may direct the purchaser to suspend all payments to the nonpaying working interest owner until the case is settled.

Suspended funds received by the operator from the purchaser pursuant to a court settlement reduces the bad debt deduction claimed. If the funds exceed the bad debt deduction claimed, the excess must be included as ordinary income.

If the operator is assigned the interest in the nonpaying working interest owner's property, the bad debt deduction must be reduced by the amount of the fair market value of the property received and assign this value to the leasehold cost of the new interest in the property. A determination of the fair market value of the property at the time of the court settlement or final decree must be made, if these documents do not provide a value. Usually the taxpayer will already have an interest in the same property. Reserves would have been determined for the operator's interest in the property for the year for financial or tax depletion purposes. The reserve report will usually have a discounted cash value of the property that can be used for fair market value purposes. Thus, you will have to convert the operator's value to 100 percent of the property value and multiply it by the nonpaying working interest owner's interest. Examiners should be cautioned that when the working interest revenue and expense percentage are not the same, additional steps must be taken. The steps described above are very general. However, if one is investigating a fair market valuation issue that is material in amount the assistance of an engineer is needed.

Sometimes the operator will no longer want to deal with the nonpaying working interest owner because of all the continuing problems it has had collecting its cost. When this happens, the operator might purchase the nonpaying working interest owner's interest in the property as part of the settlement. If this happens, the purchase price will usually be spelled out in the settlement documents.

Examiners should secure a list of the items and amounts that make up the bad debt deduction from the taxpayer. When making the request for the list, also ask the taxpayer to provide an explanation of each item and how each amount of the bad debt was calculated. The calculation should be reviewed. There might be material additions and reductions to the net bad debt deduction. Determine the nature of these additions and/or reductions by looking at the underlying source document.

If any of the items were due to nonpayment of joint interest billings, ask the taxpayer what steps were taken to obtain payment. If no steps were taken, ask why. Most operating agreements will give the operator specific remedies for nonpayment. If the property was nonproductive, determine whether the taxpayer is dealing with the same person on other new ventures. Determine the circumstances for the nonpayment and the reason for allowing this person in any new ventures. The following are two basic questions that examining officers should ask the taxpayer:

1. Has the taxpayer requested payment from the joint interest owner or was any litigation attempted?

2. What was the outcome of the litigation?

Examiners should, also, request the correspondence file for each bad debt in question and settlement contracts. These contracts should provide the terms of any settlements reached. Compare the information obtained from the correspondence file and the settlement file to the amount of the bad debt and how it was calculated. If suspended proceeds were received, determine whether the taxpayer reduced its accounts receivable from the joint interest owner by the funds received before arriving at the amount claimed as the bad debt.

If property was received as part of the settlement, the fair market value should reduce the amount owed to the taxpayer before arriving at the bad debt deduction. Examiners should determine that the correct fair market value of the property was used to reduce the total amount owed to the operator before arriving at the bad debt deduction.

To determine whether the fair market value claimed is correct, the following steps should be taken:

1. Obtain copies of the operator's reserve calculations for the property in question. Usually the taxpayer will already have another interest in the property in question.

2. Determine the fair market value of the property received by using the discounted cash flow value of the property.

3. If the working interest revenue and expense ownership interest are different, additional steps may be required. If the fair market value is material, consult an IRS Engineer.

4. Compare the value arrived at to the fair market value which the taxpayer used.

## INTANGIBLE DRILLING COST (IDC)

There are many costs incurred in developing an oil and gas well. For tax purposes, these costs are classified into two groups: IDC and tangible equipment costs. The distinction between these two costs is very important; they are treated differently for tax purposes. Before we discuss the tax treatment, we must first be able to identify those costs which are intangible drilling and development costs, also known as IDC.

IDC are expenditures for drilling wells or developing wells (preparing them to produce) which are intangible, or which have no salvage value in themselves. Pursuant to Treas. Reg. section 1.612-4(a), IDC are "*** expenditures made by an operator for wages, fuel, repairs, hauling, supplies, etc., incident to and necessary for the drilling of wells and the preparation of the well for the production of oil and gas."

Rev. Rul. 70-414, 1970-2 C.B. 132, sets out costs which are typically IDC, not optional costs, but were held to be tangible equipment.

Therefore, IDC are all costs which are the intangible or nonsalvageable costs of drilling up to and including the cost of installing the "Christmas tree." The term "Christmas tree" refers to the pipes, valves, and fittings that are used to regulate the flow of oil and gas from the wellhead. Many times, the physical arrangement of these pipes and valves resemble a "Christmas tree." The cost of casing and the physical components of the "Christmas tree" are not IDC, but equipment costs which are capitalized and depreciated.

The following are examples of IDC:

1. Administrative costs in connection with drilling contracts.

2. Survey and seismic costs to locate a well site on leased property.

3. Cost of drilling.

4. Grading, digging mud pits, and other dirt work to prepare drill site.

5. Cost of constructing roads or canals to drill site.

6. Surface damage payments to landowner.

7. Crop damage payments.

8. Costs of setting rig on drill site.

9. Transportation costs of moving rig.

10. Technical services of geologist, engineer, and others engaged in drilling the well.

11. Drilling mud, fluids, and other supplies consumed in drilling the well.

12. Transportation of drill pipe and casing.

13. Cementing of casing, but not the casing itself.

14. Rent of special equipment and tanks to be used in drilling a well.

15. Perforating the well casing.

16. Logging costs, but not velocity surveys.

17. Costs of removing the rig from the location.

18. Dirt work in cleaning up the drill site.

19. Cost of acidizing, fracturing the formation, and other completion costs.

20. Swabbing costs to complete the well.

21. Cost of obtaining an operating agreement for drilling operations.

22. Cost of plugging the well if it is dry.

23. Cost of drill stem tests.

Now that we have identified IDC, we can discuss the tax treatment of these costs. A working interest owner in an oil or gas property has the option to elect to currently deduct IDC. This option, granted by Treas. Reg. section 1.612-4(a), is exercised by claiming IDC as a deduction on the taxpayer's return for the first taxable year in which the taxpayer pays or incurs such costs. No formal statement is necessary. If the owner of the lease is a partnership, the election must be made at the partnership level. Once the election is made, it is irrevocable and binding for all subsequent taxable years. A taxpayer who fails to claim the expenses on the first return as a deduction is deemed to have elected to capitalize the costs. The filing of an amended return after the due date of a timely filed return will not change the initial election.

If a taxpayer fails to deduct IDC as an expense on the first return, the taxpayer is deemed to have elected to capitalize such costs. Recovery of costs will be done through depletion, to the extent that they are not represented by physical property, and through depreciation, to the extent that they are represented by physical property.

Taxpayers that have made the irrevocable election to expense IDC under IRC section 263(c) have the opportunity to make a secondary election to capitalize all or any part of the IDC incurred during a taxable year. This secondary election is not extended to taxpayers who have made the irrevocable election to capitalize IDC. Intangible drilling costs paid or incurred in tax years beginning after December 31, 1989, can be deferred under IRC section 59(e) and amortized over a period of 60 months on a straight line basis. The amortization claimed under IRC section 59(e) is not considered a tax preference item for alternative minimum tax purposes.

The option to expense or capitalize domestic IDC is available to all taxpayers, both individuals and corporations, with one exception. Integrated oil companies can deduct only 70 percent of their domestic IDC currently. The remaining 30 percent must be capitalized and deducted ratably over 60 months, starting with the month in which the costs are paid or incurred (IRC section 291(b)). Foreign IDC is capitalized, with one limited exception for IDC incurred in the North Sea.

In some cases, IDC must be capitalized. In a situation where one company owns a lease, but for some reason, does not wish to expend funds to explore it, another company may approach the first company with a "farmout" proposition. For example, the second company may propose that it will fund the drilling of the first test well in exchange for 50 percent of the leasehold interest. In this case, 50 percent of its drilling costs must be capitalized to leasehold acquisition cost. However, if the farmout agreement provides that the second company will receive 100 percent of the production until the cost of drilling is recovered, at which time its interest will drop to the aforementioned 50 percent, the company is entitled to deduct 100 percent of its expended IDC.

In another example, Company A has a lease of its own near or next to the lease of Company B. Company A may contribute an amount to Company B encouraging the drilling of a test well (dry hole or bottom hole contribution). If Company B establishes the probable productivity of the payer's lease, these payments must be capitalized to the payer's lease and must be recognized as ordinary income by the payee.

The Tax Reform Act of 1986 expanded the applicability of IDC as a tax preference item for tax years beginning after December 31, 1986. IDC is a tax preference item applicable to all individuals and corporations in computing the alternative minimum tax. Prior to 1987, IDC was a tax preference item for individuals only. The preference for IDC is defined in IRC section 57(a)(2). It is equal to the amount by which the "excess" IDC exceeds 65 percent of net income of the taxpayer from all oil, gas, and geothermal properties for the taxable year. IRC section 57(a)(2)(B) should be looked at for the definition of "excess IDC." However, this area of concern will cease after 1992 with regard to independent producers and royalty owners. The Energy Policy Act of 1992 repealed the alternative minimum tax IDC preference item for independent producers and royalty owners, not integrated oil companies. The repeal is effective for taxable years beginning after December 31, 1992.

In the examination of IDC, the two main items to note are the following:

1. Was a proper election to deduct IDC made?

2. Are the costs in fact intangible and not depreciable asset costs?

The classification of IDC claimed for offshore wells drilled from offshore platforms is very technical. The determination of whether they are, in fact, capital in nature is most difficult. Therefore, petroleum engineering assistance should be requested.

## **Audit Techniques**

Since IDC is a tax preference item for alternative minimum tax for taxable years beginning before January 1, 1993, it is important to properly separate IDC from LOE. There may be very subtle differences. For instance, the costs relating to servicing a well, including pulling rods, acidizing, fracturing, and cleaning out, are LOE. The cost of fracturing the production sands before production begins is IDC. To properly categorize the expenditures, it is important to analyze the invoice or billing from the drilling contractor or the operator to determine exactly what services or equipment were provided. If you are examining a working interest owner who is not the operator, remember that you don't have to stop at the joint interest statement provided by the operator. You can inspect the original records in the operator's possession.

The following are some suggested useful auditing techniques for IDC.

1. Determine if the taxpayer has made a proper election to deduct IDC as a current expense.

2. Test the larger deductions in the intangible development expense account.

   a. Schedule large amounts.

   b. Request invoices.

   c. Request AFEs.

   d. Compare above documents with amounts claimed.

3. Inspect the drilling contracts on a selected basis, especially December deductions.

4. Determine if prepaid IDC is required by the contract, or if it is merely a deposit, and whether or not it was paid directly to the drilling contractor.

   a. Determine when the well was "staked" and when work was started.

   b. Consider the facts surrounding the prepaid IDC in relationship to Rev. Rul. 71-579, 1971-2 C.B. 225 and Rev. Rul. 71-252, 1971-1 C.B. 146.

   c. Consider the effect of an adjustment. Does the adjustment have tax significance, or would it be a mere "rollover?" Remember the timing of IDC deduction could affect the net income limitation for percentage depletion under IRC section 613A.

5. Scan the depletion schedules to determine which newly acquired leases are productive.

   a. Have the drilling costs been shown as a deduction on the leases for the 50 percent percentage depletion limitation?

   b. Prepare a list of new productive leases from the depletion schedule.

6. From the list of new productive leases prepared, request the lease files on all new productive leases, or on a selective basis if the number is large.

   a. Review the lease files to determine if the taxpayer's ownership corresponds with the amount of TDC deducted. If not, why not? Is the deduction allowable?

   b. Review assignments, correspondence, and related documents to determine if the taxpayer has drilled for its interest in the lease, and if the taxpayer is "carrying" other owners.

c. If transactions are found, has the taxpayer handled them correctly? See Revenue Rulings 70-657, 1970-2 C.B. 70; 71-206, 1971-1 C.B. 105; and 77-176, 1977-1 C.B. 77.

7. Scan the producing lease account in the asset section of the ledger.

   a. Note the leases that have been removed (credits).

   b. Have the removed leases been reported as sales?

   c. Should IDC be recaptured in accordance with IRC section 1254?

8. Allocate a reasonable amount of administrative overhead costs to IDC for tax preference purposes before computing the minimum tax.

   a. Usually, this can be done by allocating overhead based on direct departmental costs.

   b. In many cases, this can be easily accomplished by using the taxpayer's work papers prepared for the purpose of allocating overhead for depletion purposes.

9. Verify that the taxpayer owned the entire working interest during the complete payout period. Entire ownership is required for the taxpayer to be allowed to deduct 100 percent of the IDC in a carried interest arrangement.

10. Has surface casing been deducted?

11. Has IDC been shown in operating expenses incorrectly to avoid minimum tax under IRC section 57 or recapture under IRC section 1254?

## LEASE AND WELL EQUIPMENT

Lease and well equipment, also known as tangible equipment costs, is the equipment and facilities used on the lease for the production of oil or gas. These items have potential salvage value and are capital expenditures.

The following are examples of costs associated with lease and well equipment.

1. Surface casing.

2. Equalization payments of a unitization when paid in connection with equipment.

3. Cost of well casing.

4. Salt water disposal equipment and well.

5. Transportation of tubing to supply yard, but not from supply yard to well site.

6. Cost of production tubing.

7. Cost of well head and "Christmas tree."

8. Cost of pumps and motors including transportation.

9. Cost of tanks, flow lines, treaters, separators, etc., including transportation.

10. Dirt work for tanks and production equipment.

11. Roads constructed for operation of the production phase.

12. Laying pipelines, including dirt work and easements.

13. Installation costs of tanks and production equipment.

14. Construction costs of truck turnaround pad and overflow pits at new tank battery.

**DEPLETION**

Oil and gas properties are wasting assets, since the amount of minerals in place are finite. Once a property becomes producing, the taxpayer wants to recover its leasehold costs. The Code allows the taxpayer to recover these costs through the depletion deduction. There are two methods for computing depletion, cost and percentage. The taxpayer must take the greater deduction of the two methods. Both methods are on a property-by-property basis. The cost depletion method is essentially a units-of-production method. For the taxpayer to receive the benefit of a cost depletion deduction, the taxpayer must have basis available in the property. The percentage depletion deduction is based on a percentage (currently 15 percent) of gross income from the property. IRC section 613A(c)(6), amended by the Revenue Reconciliation Act of 1990, increases the percentage depletion with respect to marginal production properties for tax years beginning after December 31, 1990. The increase is 15 percent plus 1 percentage point for each whole dollar that the "reference price" for crude oil for the immediately preceding calendar year is less than $20 per barrel. The amount of the percentage depletion deduction is limited to 50 percent (or 100 percent after 1990) of the net income of the property, performed on a property-by-property basis, and 65 percent of the taxpayer's taxable income. The allowable depletion deduction is the greater of the two methods.

A taxpayer must have an economic interest in the property to claim a deduction for depletion, with the exception of production payments treated as loans and installment bonuses under IRC section 636. The law further limits the taxpayers entitled to a percentage depletion deduction to entities that qualify as independent producers and certain royalty owners. There are special rules that apply to transfers of proven oil and gas properties. See the section entitled "Transfers of Proven Properties" for the rules.

In determining whether to propose adjustments to depletion, the examiner should be aware of the intricacies of the depletion calculation. Will changing an incorrectly classified direct expense from one property to another, or changing an overhead method, result in a change to the 50 percent (or 100 percent) net income limitation on any properties? If so, is the change material enough to warrant the time involved? On the properties with the material change, will the taxpayer be allowed a cost depletion deduction greater than the corrected percentage depletion deduction? Will alternative minimum tax negate the entire adjustment to depletion? It should be noted that although a large adjustment may be made to overhead or to a direct expense of a property for depletion purposes, the tax effect may be minimal. The adjustment(s) may not affect the properties which were limited by the 50 percent (or 100 percent) net income limitation or the properties may have a cost depletion deduction that would entitle them to a deduction close to the percentage depletion deduction for the property.

## ECONOMIC INTEREST

A taxpayer has an economic interest when it has acquired any interest in a mineral in place, by any form of legal relationship, and has vested rights to the income from the extraction of the mineral that is looked to for a return of capital. A person who has no capital investment in the mineral deposit does not have an economic interest merely because the taxpayer gains an economic or monetary advantage from production through a contractual relationship. The contractual right to purchase oil or gas after it has been produced is an example of an economic advantage (Rev. Rul. 68-330, 1968-1 C.B. 291).

### Cost Depletion

The cost depletion deduction assures the owner of an oil and gas producing property a tax deduction equal to the investment in the mineral property as the reserves are depleted. Examiners need to become familiar with Treas. Reg. section 1.611-2(a) and section 1.612-3(a) for computing cost depletion.

The cost depletion deduction for a property is computed as follows:

```
ADJUSTED       UNITS SOLD DURING THE TAX YEAR           CURRENT
BASIS OF [X]   --------------------------------       = COST
PROPERTY       UNITS SOLD     REMAINING RECOVERABLE      DEPLETION
               DURING THE [+] RESERVES AT                DEDUCTION
               TAX YEAR       YEAR END
```

OR

```
  ADJUSTED BASIS OF THE PROPERTY          UNITS SOLD   CURRENT
------------------------------------ [X]  DURING THE = COST
UNITS SOLD    REMAINING RECOVERABLE       TAX YEAR     DEPLETION
DURING THE [+]     RESERVES AT                         DEDUCTION
TAX YEAR             YEAR END
```

**Units Sold**

In the selection of a unit of mineral for depletion, preference shall be given to the principal or customary unit or units paid for in the products sold, such as barrels of oil or MCF for gas. Some taxpayers convert barrels of oil to MCF of gas, or gas to barrels, by reference to the value of each. Thus, both oil and gas enter into the calculation, although Treas. Reg. section 1.611-2(a) indicates only one should be used. This usually results in an equitable deduction. Any adjustment to the method usually is small and insignificant.

For a cash basis taxpayer, units sold includes only units for which payment was received during the period. For an accrual basis taxpayer, the units sold shall be determined from the taxpayer's inventories kept in physical quantities and in a manner consistent with his or her method of inventory accounting under IRC section 471 or section 472. No units should be included for which depletion was allowed in a prior period.

If the taxpayer received prior period price adjustments, determine if the taxpayer included the barrels or MCF in the current period "units sold" for cost depletion. If the taxpayer did include prior period price adjustments in the current period "units sold," exclude these units.

**Adjusted Basis of Property**

An allowable deduction for depletion (cost or percentage) will reduce the basis of a property, as determined under IRC section 1011, for the cost depletion computation. It should be noted that cost depletion is limited to the adjusted basis of the property, whereas percentage depletion can exceed it. The taxpayer should maintain accounts which have accumulated all the capitalized costs and allowable depletion (percentage and cost) by property. If costs exceed the depletion reserve (accumulated depletion), the difference is the remaining basis. The effect of this is that an addition to capital of any asset may be fully offset by previously allowed percentage depletion, so that immediately after a substantial capitalization, the taxpayer's remaining basis may be zero (Rev. Rul. 75-451, 1975-2 C.B. 330 and Treas. Reg. §1.614-6(a)(3), Example 1).

**Reserves**

The reserves to be included in the calculation of cost depletion for tax purposes include proved and probable reserves in accordance with Treas. Reg. section 1.611-2(c). Regulations indicate probable or prospective reserves are to be included only if they are extensions of known deposits or are new bodies of mineral whose existence is indicated by a high degree of probability. Examining officers should be cognizant that taxpayers may have different categories with similar definitions. Some additional information can be found in the *Journal of Petroleum Technology*, May 1987, pages 577-78.

## Cost Depletion on Wildcat Acreage

If a taxpayer (landowner) receives a lease bonus on wildcat acreage and claims cost depletion equal to 100 percent of its cost, this has the effect of claiming that the minerals are worthless as they supposedly will produce no future income. Worthlessness must be proven by an identifiable event, and in this case, no such event has occurred. Further, it is assumed that the lease itself has value or the lessee would not have paid the bonus. Therefore, cost depletion should not be allowed unless it is possible to make a reasonable estimate of future income and that estimated income is not zero. However, for a contrary decision, see *Collums v. United States*, 480 F. Supp. 864, 45 A.F.T.R. 2d 80-751 (D Wyo. 1979), with respect to which no action on decision has been issued.

## PERCENTAGE DEPLETION

## Independent Producer

An independent producer, as defined by IRC section 613A(d)(2), is a producer who does not have more than $5 million in retail sales of oil or gas in a year (a retailer) and who does not refine more than 50,000 barrels of crude oil on any day during the year (a refiner). No percentage depletion is allowed to a taxpayer to the extent its average daily production of domestic crude oil and domestic natural gas exceeds 1,000 barrels of oil per day or 6,000 cubic feet of gas per day.

To determine the taxpayer's depletable oil quantity, the taxpayer's average daily oil and gas production must be determined. A taxpayers average daily oil production and average daily gas production is determined by dividing its total crude oil production and total gas production by the number of days in that tax year, excluding oil and gas that result from a secondary or tertiary process, gas sold under a fixed contract, regulated natural gas, and production from a proven property transferred after 1974 (secondary and tertiary properties may be transferred and still qualify for percentage depletion). Remove the taxpayer's average daily secondary and tertiary production and the number of barrels which the taxpayer elects to convert from natural gas to oil (1 barrel equals 6 MCF) from the tentative oil quantity (1,000 barrels). Thus the taxpayer's depletable oil quantity is the portion of the average daily barrels within the 1,000 barrel limit (secondary and tertiary recovery barrels, gas converted to oil, and the balance of the oil barrels).

For purposes of applying the 1,000 barrel limitation, all members of a controlled group are treated as one taxpayer. Also, a family group, which consists of an individual, spouse, and minor children, will be allowed only one 1,000 barrel limitation.

## Transfers of Proven Properties

The Revenue Reconciliation Act of 1990, repealed the transfer limitation rules. Percentage depletion is now allowable on transferred proven oil and gas properties for transfers after October 11, 1990. This repeal is applicable to all domestic oil and gas producing properties.

An oil and gas property is proven if, at the time of the transfer, all of the following conditions exist:

1. Any oil and gas has been produced from a mineral deposit which underlies such property (production from the deposit may not necessarily have been from the property);

2. Prospecting, exploration, or discovery work indicates it is probable that the property will have gross income from oil or gas from such deposit sufficient to justify development; and

3. The fair market value of the property is 50 percent or more of the fair market value of the property, minus actual expenses of the transferee for equipment and IDC, at the time of the first production from the property subsequent to transfer and before the transferee transfers its interest.

All three provisions, cited above, of Treas. Reg. section 1.613A-7(p) must be satisfied for the property to be proven property. If this issue is unagreed, an engineer referral must be made to determine the fair market value of the property.

## Gross Income from the Property

Gross income per the tax return and gross income per the depletion schedule will generally not be the same. various adjustments must be made to determine gross depletable income. Examples of oil and gas revenues per the general ledger may be gas sales, oil sales, condensate sales, plant products, royalty gas sales, royalty oil sales, and royalty condensate sales. it should be noted the plant products are not gross depletable income. Examples of accounts not included in depletable income are plant operating income (for example, propane, butane, and ethane sales), marketing income, truck rentals, pipeline fees, and consulting fees. This list is not all inclusive, but is to be used as a reference. Only 100 percent of the proceeds of actual sales of oil and gas, not production, are subject to depletion. The proceeds, subject to depletion, generally are limited to the representative market or field price of sales in the immediate vicinity of the well. Gross income from the property includes any production or severance taxes which are the responsibility of the seller.

There are several adjustments to book income to determine income subject to depletion:

1. Transportation costs: These costs must be isolated from production income. They are not subject to depletion. (Treas. Reg. section 1.613-3(a) and Rev. Rul. 75-6, 1975-1 C.B. 178.)

2. Lease Bonus Exclusion: Gross income is reduced by a portion of the bonus payment to arrive at depletable income. (Rev. Rul. 79-73, 1979-1 C.B. 218; Rev. Rul. 81-266, 1981-2 C.B. 139; and *Helvering v. Twin Bell*, 293 U.S. 312 (1934).)

3. Royalty Income: If paid by the working interest owner, it must be excluded from depletable income.

4. Advanced Royalties: Gross income is reduced by a portion of the advanced royalty payment to arrive at depletable income.

5. Delay Rentals: When received by the landowner, delay rentals are not payments for production of oil and gas and are not subject to depletion.

6. Taxes: The amount received by a producer is usually net of production and severance taxes; this amount received generally needs to be grossed up by the amount of the taxes for depletion purposes.

There are instances in which there is no determinable representative market or field price. In these instances, it is necessary to make a determination of gross income from the property by studying the data. These situations have given rise to several court cases. The following court decisions address the determination of gross income:

1. *Weinert v. Commissioner*, 294 F.2d 750 (5th Cir. 1961), 8 A.F.T.R. 2d 5417, 61-2 U.S.T.C. 81,606.

2. *Shamrock Oil and Gas v. Commissioner*, 346 F.2d 377 (5th Cir. 1965).

3. *Mountain Fuel Supply Co. v. United States*, 449 F.2d 816 (10th Cir. 1971), 28 A.F.T.R. 2d 71-5833, 71-2 U.S.T.C. 87,650, cert. denied, 405 U.S. 989.

4. *Exxon Corporation and Affiliated Companies v. Commissioner*, 102 T.C., No. 33 (1994).

If the depletion claimed for gas production is significant and there is no determinable representative market or field pricer examining officers should request the assistance of an engineer.

Figure 3-2 below is a chart to assist examiners.

**Figure 3-2**

**Income Flow Sheet for Depletion**

| Per 1120 Tax Return | Per General Ledger | Deple-tion | Adjustment Due to Depletion Deduction |
|---|---|---|---|
| Line 1 Gross Receipts | Lease Income | | Transportation — |
| | Gas Sales --------> | Yes | Rev. Rul. 75-6, |
| | Oil Sales --------> | Yes | 1975-1 C.B. 178 |
| Line 7 Gross | Condensate Sales--> | Yes | Treas. Reg. section |
| Royalties | Plant Products | NA | 1.613-3(a) |
| | Plant Operating Inc | | Bonus — |
| | Propane | NA | Rev. Rul. 79-73, |
| | Butane | NA | 1979-1 C.B. 218 |
| | Ethane | NA | Rev. Rul. 81-266 |
| | | | 1981-2 C.B. 139 |
| | | | Helvering v. |
| | | | Twin Bell |
| | Royalty | | |
| | Gas Sales --------> | Yes | Advance Royalties |
| | Oil Sales --------> | Yes | |
| | Condensate Sales--> | Yes | Delay Rentals |
| | Marketing Income | NA | Gross up TP's |
| | | | interest for |
| | Truck Rentals | NA | severance tax if it |
| | | | is not already the |
| | Pipeline Fees | NA | gross amount. |
| | Consulting Fees | NA | |

## NET INCOME OF THE PROPERTY

Percentage depletion is computed on a property-by-property basis. Examining officers should become familiar with the 'property concept' before attempting to determine taxable income from the property.

Taxable income from the property is important because the percentage depletion deduction is limited to a percentage of taxable income from the property, computed without regard to depletion allowance, per IRC section 613(a). For taxable years beginning before January 1, 1991, the net income limitation is 50 percent. For taxable years beginning after December 31, 1990, the net income limitation has been increased from 50 percent to 100 percent of net taxable income. The increased limitation, 100 percent, is applicable only to oil and gas properties.

## EXPENSES OF THE PROPERTY

The taxpayer will claim various expenses (for example, lease operating, severance taxes, production taxes, depreciation, overhead, etc.) to compute each property's net income. These expenses will be directly attributable to the property or the taxpayer will be required to use an allocation method. See the section entitled "Overhead Allocation" below for a discussion of allocation methods with regard to depletion.

A taxpayer can manipulate the percentage depletion deduction. This can be accomplished by reallocating direct expenses between properties, manipulating the net income limitation of each property subject to the limitation. When examining percentage depletion, the income and expenses of each property should have a correlation to the other properties' income and expenses. If not, ask for an explanation and sample some of the invoices associated with the properties in question. There may be a plausible explanation such as the well was in an area that is more costly to produce, expensive workover cost, etc.

## OVERHEAD ALLOCATION

Expenses must be separated between direct and indirect. Direct expenses, as we have already learned, are easily apportioned to their specific activity or property. Indirect expenses, also known as overhead, are those not directly attributable to any specific activity or property. Some examples of indirect expenses are supervisory salaries, utilities, rent, depreciation of office equipment, office supplies, employee benefit programs, marketing expenses, general and administrative expenses, accounting department, land department, etc.

Each separate activity should draw a portion of the overhead that is incurred. In the oil and gas business, a taxpayer may have a land and exploration department which develops nonproducing properties. The taxpayer may also be the operator for the joint interest owners and, therefore, bear additional overhead and administrative costs to account to the joint interest owners. The overhead associated with the operation of the joint venture cannot be allocated to the production of oil and gas. It is a separate activity and should draw an appropriate portion of overhead. The overhead allocation may have to be accomplished in several layers, depending on the complexity and diversity of the company. The method of allocation does not have to be the same for each layer as long as it is reasonable and the deductible expenditures have been fairly apportioned (*Occidental Petroleum Corp. v. Commissioner*, 55 T.C. 115 (1970)). If the taxpayer has nonproducing oil and gas properties, the first layer of allocation cannot be based on gross income. While the burden of proof is on the taxpayer, as a practical matter the Internal Revenue Service must be prepared to demonstrate specific bias in the taxpayer's method of overhead allocation.

The formulas for "Direct Expense Allocations" and "Gross Income Allocations" are as follows:

DIRECT EXPENSE ALLOCATION FORMULA:

| | | |
|---|---|---|
| Expense Allocation Overhead Ratio | = | Direct Expenses Per The Property<br>---------------------<br>Total Direct Expenses (All Properties) |

GROSS INCOME ALLOCATION FORMULA:

| | | |
|---|---|---|
| Gross Income Allocation Ratio | = | Gross Income Per The Property<br>---------------------<br>Total Gross Income (All Properties) |

**Audit Techniques**

In the initial interview, examiners should determine how the taxpayer allocates overhead. Also, one should determine if the taxpayer has an economic interest in the property. Scan the properties to make sure that overhead is allocated to both producing and nonproducing properties. In addition, the properties should be scrutinized to ensure that all business activities are receiving their share of overhead including investments, production, refining, etc. Interest expense paid on money borrowed for operating capital is an overhead item which should be capitalized as an accumulating production cost subject to the rules of IRC section 263A. The taxpayer should net interest expense to the extent of interest income before allocation.

**INFORMATION REQUIRED TO COMPUTE DEPLETION ALLOWANCE**

There is certain information that examiners must secure before the maximum allowable depletion can be computed. Below is the list of information that is needed:

1. What is the taxpayer's average daily production of domestic crude oil and how was it computed (IRC section 613A(c)(2))?

2. Is the taxpayer required to share the tentative depletable oil quantity with related entities or family members (IRC section 613A(c)(3) and IRC section 613A(c)(8))?

3. If the answer to question 2 is "yes," determine the taxpayer's individual share of tentative oil quantity under IRC section 613A(c)(3) and IRC section 613(c)(8).

4. Which properties were producing under "regulated" natural gas and natural gas sold under a "fixed price contract?"

5. Which properties are producing as a result of secondary and tertiary activities?

6. Which properties were producing as "proven" properties (IRC section 613A(c)(9))?

7. Which purchased properties qualify for depletion under exceptions to the general rules regarding transfers?

8. Is the percentage depletion limited to 65 percent of adjusted taxable income?

9. Have overhead expenses been allocated to the properties for percentage depletion purposes?

10. Are any of the properties limited to 50 (100) percent of net income for percentage depletion?

11. Is the taxpayer a refiner or retailer (IRC section 613A(d)(2) or IRC section 613A(d)(4))?

It is imperative that examiners tie down "gross income" for computing depletion. Below are suggested audit techniques for establishing "gross income" for depletion purposes:

1. Gross income for depletion should be reduced by transportation costs. Determine how the taxpayer is handling transportation costs.

    a. Inspect posted price bulletin. If the price paid is wellhead price, it does not include transportation.

    b. If a spot price is paid, look to the contract or the prices paid per the posted price bulletin for the general vicinity.

    c. If the price the taxpayer received is higher, the difference could be transportation charges. If they are transportation charges, back them out before computing depletable income.

2. If the taxpayer is an operator of any properties, determine how the taxpayer handles the income received for operating the property for depletion purposes.

    a. The taxpayer should treat the income as a separate activity which is allocated a share of the taxpayer's overhead.

b. The taxpayer should not reduce expenses or increase income of the properties it operates by the amount of the operator income received.

c. The taxpayer should not reduce the general overhead allocated to the properties by the amount of operator income received.

3. The following amounts are to be treated as ordinary income not subject to percentage depletion:

   a. Lease bonuses, royalties paid in advance, and minimum and shut in royalties received or accrued after August 16, 1986. Prior to this date, these items were allowed percentage depletion.

   b. Delay rentals.

   c. Ad valorem taxes paid by the lessee for the lessor.

## ALTERNATIVE MINIMUM TAX

There are two tax preference items which are applicable to oil and gas. They are percentage depletion and IDC. These tax preference items are applicable to independent producers and royalty owners through taxable years beginning before January 1, 1993. The Energy Policy Act of 1992 repealed both alternative minimum tax preference items, percentage depletion and IDC, for independent producers and royalty owners, not integrated oil companies. The repeal is effective for taxable years beginning after December 31, 1992.

### Percentage Depletion

The tax preference item for depletion is the excess of percentage depletion over the adjusted basis of the depletable interest at the end of the taxable period.

### Intangible Drilling Costs

The excess of IDC, in connection with oil and gas wells that are expensed under IRC section 263(c), over the amount which would have been allowable if the costs had been capitalized and a straight line recovery of IDC had been used with respect to these costs is the tax preference item.

As previously discussed, the amortization claimed under the secondary election set out in IRC section 59(e) is not considered a tax preference item for alternative minimum tax purposes.

## Alternative Tax Energy Preference Deduction

The Revenue Reconciliation Act of 1990 made significant changes to allow a special energy deduction in computing the alternative minimum tax. The act added IRC section 56(h) creating the new deduction applicable to tax years beginning after December 31, 1990. This deduction, available for the taxable years of 1990, 1991, and 1992, may not be claimed by integrated oil companies. The Energy Policy Act of 1992 repealed the deduction effective for taxable years beginning after December 31, 1992.

The deduction is an amount equal to the sum of:

1. 75 percent of the portion of the IDC preference attributable to "qualified exploratory" costs;

2. 15 percent of the portion of the IDC preference not attributable to "qualified exploratory" costs; and

3. 50 percent of the portion of the percentage depletion preference (as determined under IRC section 57(a)(1)) which is attributable to marginal production of oil and gas.

The alternative tax energy preference deduction is limited to 40 percent of the alternative minimum taxable income determined without regard to either the special energy deduction or the alternative tax net operating loss deduction. Any amount limited by the 40 percent is not allowable as a carry forward to another taxable year.

## Qualified Exploratory Costs

The new Code section defines "qualified exploratory" costs as IDC of a taxpayer, other than an integrated oil company, that the taxpayer may elect to deduct as IDC under IRC section 263(c), and are paid or incurred in connection with the drilling of an exploratory well located in the United States.

The "qualified exploratory" costs do not include any costs paid or incurred in constructing, acquiring, transporting, erecting, or installing an offshore platform, or with respect to the drilling of a well from an offshore platform unless it is the first well that penetrates a reservoir.

**Exploratory Well**

An exploratory well is any of the following oil or gas wells.

1. An oil or gas well that is completed (or if not completed, with respect to which the drilling operations cease) before the completion of any other well that is located within 1.25 miles of the well, and is capable of production in commercial quantities.

2. An oil or gas well that is not described in (1) but which has a total depth that is at least 800 feet below the deepest completion depth of any well within 1.25 miles that is capable of production in commercial quantities.

3. An oil or gas well capable of production in commercial quantities that is not described in (1) or (2) but which is completed into a new reservoir, except that this shall not apply to a gas well if the gas is produced (or will be produced) from Devonian shale, coal seams, or a tight formation.

An "engineers certificate" must be obtained from the operator by the taxpayer who has claimed the deduction to ensure that the well qualifies and will be treated as an "exploratory well." Rev. Proc. 92-62, 1992-2 C.B. 240, requires the petroleum engineer, that certifies the well, be duly registered, licensed, or certified in any state.

**Marginal Production**

"Marginal production" includes domestic oil and gas production from the following.

1. A stripper well property which is property that has an average daily production of 15 barrel equivalents or less per producing oil or gas well in any calendar year.

2. A property of which substantially all of the production is heavy oil (that is, crude oil which had a weighted average gravity of 20 degrees API or less at 60 degrees Fahrenheit).

The percentage depletion preference attributable to a marginal production property is based on the percentage depletion preference that relates specifically to the marginal wells. The taxpayer must determine what wells produce percentage depletion in excess of basis. If only non-marginal wells produce percentage depletion in excess of basis, there is no marginal depletion preference. If the taxpayer has a property that has both marginal and non-marginal wells, the property's basis must be allocated on a reasonable basis between the two.

**Phase Out of the Deduction**

The special energy deduction is phased out in taxable years that follow the calendar years in which the price of oil exceeds a certain level. The deduction is completely phased out if the price of oil for the calendar year is $6 per barrel more than $28 per barrel (adjusted for inflation). The preference deduction is ratably reduced when the price of oil for the calendar year exceeds $28 per barrel as adjusted for inflation, in an amount less than $6 per barrel. For example, if in a year the price exceeds the adjusted base level by $3, then the deduction would be reduced by 50 percent ($3 over $6).

**Audit Techniques**

**Depletion**

If the taxpayer is claiming percentage depletion, determine whether the taxpayer has a preference item for alternative minimum tax. IRC section 57(a)(1) states that with respect to each property, the excess of percentage depletion over the adjusted basis of the depletable interest at the end of the taxable year, is a tax preference item. The adjusted basis of the property is determined without regard to the depletion deduction for the taxable year.

The taxpayer must supply verification of the adjusted basis of the depletable property at the beginning of the year. Most taxpayers include the adjusted basis of the property in their depletion schedule. If the taxpayer is unable to provide this verification, then all percentage depletion will be considered as a tax preference item. Also, ensure that the taxpayer has not included the depreciable basis on the depletion schedule.

**Intangible Drilling Costs**

If the taxpayer has made an election to expense IDC, then the excess IDC will be a tax preference item for purposes of alternative minimum tax under IRC section 57(a)(2). The excess IDC is the excess of the intangible drilling and development costs, in connection with oil and gas wells that are expensed under IRC section 263(c), over the amount which would have been allowable if the costs had been capitalized and straight line recovery of intangibles had been used with respect to these costs. The straight line recovery is either amortization over 120 months or the cost depletion method for those wells, whichever is greater.

The amount of the tax preference for excess IDC is the amount by which the excess IDC is greater than 65 percent of the net income of the taxpayer from the oil and gas properties. To determine the amount of tax preference for excess IDC, the following three steps must be followed:

1. Compute EXCESS IDC.

   a. Compute straight line recovery of IDC. Taxpayers may choose one of the following methods:

      1) 120 MONTH RULE.

```
Months of Production                Straight-Line
--------------------- [X] IDC = Amortization
    120 Months                      Of IDC
```

      2) COST METHOD.

```
Months of Production                  Straight-Line
----------------------- [X] IDC = Amortization
Units Sold (+) Year End               Of IDC
               Reserves
```

   b. Compute "Excess IDC" as Follows.

```
IDC Claimed on Return (Do Not Include IDC on Dry Holes)
(–) Straight-line Recovery of IDC
-------------------------------------------
Excess IDC [On a Well-by-Well Basis]
===========================================
```

2. Compute NET INCOME OFFSET as Follows.

```
Gross Income from the Property
(–) Expenses (Including IDC Per Return)
--------------------------------------
Net Income from the Property
(×) 65 Percent
--------------------------------------
Net Income Offset
=================
```

3. Compute TAX PREFERENCE AMOUNT as Follows.

```
Excess IDC (As Computed Above)
(–) Net Income Offset (As Computed Above)
-----------------------------------------
Tax Preference Amount
=====================
```

## ALTERNATIVE TAX ENERGY PREFERENCE DEDUCTION

Examiners should ensure that the amount claimed as IDC associated with an "exploratory well" is equivalent to and deductible as IDC under IRC section 263(c).

A map depicting the location of all wells should be reviewed if the well is certified because its location is at least 1.25 miles from a commercially productive well. The map should depict all wells regardless of who actually operates them. Examiners should consider obtaining and reviewing maps prepared by state jurisdictional agencies and commercial map companies for verification of the maps submitted by the taxpayer.

A well is presumed to be capable of production in commercial quantities at the time that it has been completed with the installation of a "Christmas tree," or other mechanism to regulate the flow of oil or gas. A good source of information can be found in the service company's bill to the operator for the installation of equipment associated with preparing a well for production. This bill would include costs for the labor crew and equipment for installing the "Christmas tree" and flow lines, leveling the tank pad, and setting the tank, etc.

Examiners should also obtain and review the reports filed with the state or federal regulatory agency for each particular state. Examples of reports could be a drilling permit, well completion or plugging report, test reports, production reports, and recompletion reports.

If the taxpayer is claiming that the well is at least 800 feet below the deepest completion depth of any well within 1.25 miles and is capable of production in commercial quantities or the well is completed in a new reservoir, well logs and seismic maps should be reviewed. These logs and maps will assist in determining the depth and reservoir delineation.

Exploratory wells do not include a well drilled for the purpose of supporting production from another well or wells. This would include wells drilled solely for the purpose of injecting gas, water, steam, or air. Wells drilled for water disposal or water supply would not qualify. Stratigraphic test wells are wells drilled for the purpose of obtaining information specific to a geologic condition and would not qualify. Stratigraphic wells are drilled without the intention of being completed for the production of hydrocarbons.

## SELF-EMPLOYMENT INCOME

Nonoperated interests are generally considered passive income and not subject to self-employment tax. See Rev. Rul. 69-355, 1969-1 C.B. 65. However, when a nonoperated interest is obtained as a result of personal services and the value is not taxed when received, self-employment tax is applicable.

Overriding royalty interests (ORRI), retained in working interests, are routinely acquired for use in a taxpayer's trade or business. An ORRI used in the trade or business is considered a part of that business for purposes of computing self-employment tax.

Working interests in an oil and gas venture are considered to be engaged in the active conduct of a trade or business and are subject to self-employment tax. The taxpayer does not have to be the operator of the property to be subject to self-employment tax.

Minority ownership in oil and gas working interests are governed by a joint operating agreement that is agreed to by the working interest owners. This agreement creates a partnership for statutory purposes outside of IRC subchapter K. As a result, the oil and gas income constitutes self-employment income under IRC section 1402. See Rev. Rul. 58-166, 1958-1 C.B. 324, and *Frances Cokes v. Commissioner*, 91 T.C. 222 (1988).

A limited partner may not treat any loss claimed on its partnership return as a net loss from self-employment because the distributive share on any item of income or loss of a limited partner is excludable from the computation of net earnings from self-employment. See IRC section 1402(a)(12) and *Mammoth Lake Project v. Commissioner*, 61 T.C.M. 1630.

Examiners need to scrutinize the income and losses reported on Schedule SE of Form 1040 and determine that all types are properly classified as self-employment income or losses. Income and expenses from a joint venture will be recorded on Schedule C. The Service is not following the holding in *Hendrickson v. Commissioner*, T.C. Memo 1987-566. See instead *Frances Cokes v. Commissioner*, 91 T.C. 222 (1988).

## PASSIVE ACTIVITY LOSS LIMITATION

Before examiners even consider the application of IRC section 469, each activity must be considered for at risk under IRC section 465. Any losses limited due to the at risk rules will be allowed as a deduction in the next succeeding year, provided there is additional at risk basis of property at the end of that year. If a loss is disallowed under IRC section 465, the passive loss rules will not apply.

IRC section 469(a) denies any net losses or tax credits from passive activities. Losses and credits from passive activities may only reduce income from other passive activities. The excess is carried forward to subsequent years to offset passive activity income arising in those years. A special exception permits closely held C-Corporations to deduct passive losses against net active business income, but not against portfolio income.

The passive activity loss limitation is applied after the percentage depletion limitations. The portion of the percentage depletion deduction carried over to a subsequent year due to the 65 percent of taxable income limitation is allowed without regard to the application of IRC section 469 in that year.

All activities which are passive will be used in the computation of the allowed passive activity loss on Form 8582 for individuals, estates and trusts or Form 8810 for closely-held and personal service corporations. Taxpayers may attempt to misclassify active income as passive and passive losses as active. Therefore, examiners should review the activities listed on Forms 8582 or 8810 to determine if the taxpayer properly classified the interest.

**Oil and Gas Activities**

A passive activity does not include any working interest, operating or nonoperating, held at any time during a taxable year in any oil or gas property which does not limit the liability of the taxpayer with respect to such interest regardless of whether the taxpayer would otherwise be treated as materially participating in the activity of the property. Qualifying working interests are determined on a well-by-well basis rather than property-by-property basis. Private contractual rights which provide protection from economic loss through indemnification agreements, stop loss agreements, turnkey contracts, and insurance are not considered limitations on a taxpayer's liability for IRC section 469.

An interest in an activity as a limited partner will be considered passive. Income from oil and gas activities that do not qualify for the working interest exemption may still qualify under the material participation requirement as trade or business income. The look back rules are required when the working interest was excluded from the passive loss rules by the reason of the working interest exception rather than the material participation criteria (IRC section 469(c)(3)(B) and Treas. Reg. section 1.469-2(c)(6)).

**Portfolio Income**

Portfolio income is defined to include gross income from interest, dividends, annuities, or royalties not derived in the ordinary course of a trade or business. The gain or loss from the disposition of such property that produces such income is also considered portfolio income.

Oil and gas royalties, net profits interests and overriding royalties will generally be considered portfolio income. But there are two situations set out in the regulations that exempt royalties as portfolio income.

Treas. Reg. section 1.469-2T(c)(3)(iii)(B) provides active income treatment for royalties derived in the ordinary course of a trade or business. This exception does not apply to a taxpayer who is not a dealer in royalties.

Treas. Reg. section 1.469-2T(c)(3)(ii)(G) requires the income to be identified by the Commissioner as income derived in a trade or business. The taxpayer must request a ruling to have the royalties characterized as trade or business income. Industry publications suggest that taxpayers should request a ruling to treat oil and gas royalties as nonpassive income derived in a trade or business. Until, or if ever, the Commissioner expands the regulations to include certain oil and gas royalties as business income, oil and gas royalties are to be included as portfolio income.

The determination of whether royalties are portfolio income is made at the entity level in the case of pass through entities, such as limited partnerships and S Corporations.

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## Forms Required to be Filed with the Texas Railroad Commission

| | |
|---|---|
| Forms P-1, P-2, and P-1B | These Texas Railroad Commission forms are the producer's monthly report of oil wells and gas wells. They identify the field, lease, wells, and the amount of production by month from each well. They also show the amount of oil or gas on hand at the beginning of each month and the amount removed from the property. This report is prepared in-house and is only as reliable as the operator's books and records. |
| Form W-1 | A Texas Railroad Commission form which must be filed by the operator to receive a permit to drill, deepen, plug back, or reenter a well. It can be helpful in determining the operator's intent regarding a prospect, or an existing well. |
| Form W-2 | A Texas Railroad Commission form which may be used to report oil well potential test results, well completion, or well recompletion results. It is filed by the operator and certified by a well tester. This report can be helpful in providing background information about the well's condition. |
| Form W-3 | A Texas Railroad Commission form which is used to report the plugging and abandonment of a well. It is filed by the operator and certified by the cementing company. It can be useful in verifying when a well can be written off as a dry hole. |

In other states it may be necessary to contact the appropriate agency to obtain the required forms.

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# Chapter 4

# FINANCIAL PRODUCTS

## POTENTIAL AREA OF CONCERN RELATED TO OIL AND GAS

Due to the changing facets of the oil and gas industry, the industry has expanded its activities into the world of financial products. As a result of the volatility of prices of barrels of oil and MCFs of gas, the industry has entered hedging transactions to reduce the risk undertaken. This section of the MSSP guide is intended solely to introduce the energy markets, the vehicles used to participate, and the participants in the markets. Examining officers should refer to IRM 4232.8:(11)00, Risk Management, for suggested examination techniques relating to financial products.

## ENERGY MARKETS AND THE PARTICIPANTS

The oil market consists of three types of markets: cash market, forward market, and the futures market. The cash market, also known as the physical or spot market, is where the actual physical oil is bought and sold through individual deals. The forward market is where the oil is bought and sold between two parties with delivery taking place at a future date. The futures market trades futures contracts and options on future contracts.

### Cash Market

The cash market is where the physical oil is bought and sold through individual deals made between buyers and sellers which usually call for delivery within 30 days. This market is global in nature and is made up of major international oil companies, national oil companies, fully integrated oil companies, independents, refiners, marketers, distributors, and traders. There are cash markets generally for all types of crude oil such as West Texas Intermediate, Brent (from the United Kingdom North Sea), and Dubai. The major refineries produce gasoline, aviation fuel, distillate, and residual fuel oil.

A potential issue associated with physical transactions in the cash market is the use of a consistent identification method for positions closed. Some taxpayers match selected futures or physical contracts using a specific identification method to minimize gain reporting or to maximize losses, while matching other transactions on the FIFO basis. Taxpayers must use the first in, first out method similar to that described in Treas. Reg. section 1.1012-1(c), unless adequate records are kept on a consistent basis identifying inventory under another acceptable method.

## Types of Physical Transactions

**Alternative Delivery Procedure.** An "Alternative Delivery Procedure" (ADP) is available to buyers and sellers of New York Mercantile Exchange (NYMEX) contracts that have been matched by the exchange subsequent to the termination of the contract. Deliveries of NYMEX crude oil futures require the delivery of West Texas Intermediate, F.O.B., Cushing, Oklahoma. Deliveries of heating oil and gasoline are made F.O.B., New York Harbor. With an ADP, the buyer and seller agree to consummate delivery under terms different from those prescribed in the NYMEX specifications. An ADP can take place immediately after two parties have been matched for delivery by the NYMEX. In ADP transactions, the NYMEX and clearing firms are released from all liabilities related to the delivery negotiated between the parties. A "Notice of Intention" must be submitted to the NYMEX by the parties involved in the ADP.

Once a futures contract has been terminated through the delivery process, brokerage statements generally are not issued to record the sale, exchange, or carrying of physical commodities. The record keeping on physical transactions is generally done by the taxpayer, rather than a third party. Thus, it becomes difficult to trace and verify physical commodity transactions. Warehouse receipts for physical transactions are generally issued in bearer form.

**Exchange of Futures for Physicals.** An exchange of futures for physicals (EFP) is a transaction in which a buyer or seller may exchange a futures position for a cash position of equal quantity by submitting a notice to the exchange. The price of the exchanged futures position, the quantity of the futures and cash commodity to be exchanged, the price of the cash commodity, and other terms are privately negotiated by the parties and are not executed in an exchange or on a board of trade.

EFP transactions are an exception to the general prohibition contained in the Commodity Exchange Act against certain noncompetitive and prearranged transactions in commodity futures contracts. The Commodity Exchange Act places responsibility on the commodity exchanges for establishing rules governing EFPs. EFPs serve an important function for commercial market users by providing a means of pricing a cash transaction or making or taking delivery on their futures commitments outside the normal exchange delivery system. This allows them to offset exchange positions through privately negotiated transactions.

EFPs in energy contracts are often used to control location and timing of contracts because of the transportation costs involved. A second major advantage of EFPs is the ability for a firm to choose a party willing to take the opposite side of the transaction, or instruct its broker to locate a suitable trading partner. An EFP allows, for example, a major oil company to be sure that the other side is financially able to handle the transaction. It also ensures the company that the entity is one with which it has an established supplier/customer relationship. Specifically, the buyer can determine whether the seller is able to fulfill its delivery obligation, and the seller can evaluate the buyer's ability to take delivery. An EFP also ensures that the buyer will be able to match the delivery with the trade size at one location from one opposite party.

1. <u>NYMEX Rules</u>

New York Mercantile Exchange Rule 6.21 governs EFP transactions. EFPs can be negotiated at the time a particular energy futures contract trades or until 2 p.m. of the business day following the termination of trading in an expired futures contract. After both parties to an EFP agree to such a transaction, the NYMEX must be notified. An EFP is initially reported on a "pit card" which is a card used by floor traders or members of the NYMEX to record transactions. All NYMEX records identify the trade as an EFP, but the trade will be handled as any other futures position. The EFP is cleared in accordance with normal procedures and identified and recorded as an EFP by NYMEX (the Exchange) and clearing members involved.

NYMEX rules require that each seller and buyer satisfy the Exchange that the EFP is bona fide. NYMEX rules also ascertain that the clearing members shall obtain all documentary evidence and make that evidence available to the Exchange at their request. NYMEX requires that a clearing member submit a Form EFP-1, which documents and certifies the EFP as bona fide, to the clearing department. A Form EFP-2, which documents the actual transfer of possession of the cash commodity, must be submitted to the Exchange's Compliance Department within 5 business days after the physical delivery has occurred.

2. <u>CFTC Position</u>

Section 4c(a) of the Commodity Exchange Act prohibits wash sales, cross trades, accommodation trades, fictitious sales, and transactions that cause prices to be reported, registered, or recorded that are not true and bona fide. However, section 4c(a) provides a specific exception for EFPs. It states, "Nothing in this section shall be construed to prevent the exchange of futures in connection with cash commodity transactions or futures for cash commodities, or transfer trades or office trades if made in accordance with board of trade rules applying to such transactions and such rules shall have been approved by the Commission."

The Commodity Futures Trading Commission (CFTC) Division of Trading and Markets "Report on Exchanges for Physicals" has indicated that three essential elements must exist in order for an EFP to be considered a bona fide EFP eligible for the statutory exception. These elements are as follows:

a. There must be, both, a physical (cash) transaction and a futures transaction which are integrally related.

b. The physical commodity contract must provide for a transfer of ownership of the physical commodity to the cash buyer upon performance of the terms of the contract, with delivery to take place within a reasonable period of time thereafter; in accordance with the prevailing physical market practice. Actual delivery need not take place if the selling party offsets the obligation by other means.

c. There must be separate parties to the EFP. The accounts involved must have different beneficial ownership or be under separate control.

Two situations exist which the CFTC believes should not be considered bona fide EFP transactions. First, a transaction which fails to comply with the conditions of the section 4c(a) exception or with the exchange rules governing the transaction would be prohibited, even if it were characterized as an EFP by the parties to the transaction and cleared by the Exchange. Second, a transaction that appears to comply with section 4c(a) and any applicable exchange rules, but is intended to accomplish some illegal purpose, would be prohibited as falling outside the scope of the exception provided by section 4c(a).

In addition to the three essential elements described above, the CFTC included five additional items that an exchange or board of trade should consider when evaluating EFP transactions. The following are the five items:

a. The degree of price correlation between the cash component and the futures contract.

b. The prices of the futures and cash legs of the EFP and their relationship to the prevailing prices in either market.

c. Whether the seller has possession, the right to possession, or the right to future possession of the cash commodity prior to an EFP.

d. The cash seller's ability to perform on the delivery obligation in the absence of prior possession of the cash commodity.

e. Whether the cash buyer acquires title to the cash commodity.

Pricing oil based on the closing of a futures contract has been found in numerous cases. If a taxpayer engages in EFPs, examiners should contact a commodity specialist and/or the Petroleum Industry Program for assistance.

**Swap of Physical Commodity.** A swap is a transaction in which one grade or location of crude oil or other production is swapped for another grade or location. This is known as a commodity swap. A refiner may arrange a swap of one grade of crude for another to fulfill its changing refining needs if it can locate a willing opposite party. A location swap can be used to obtain crude oil in the desired location permitting a refiner to avoid transportation costs and associated delays in moving the oil to the refinery. A swap can also involve an exchange of crude oil for products such as gas or heating oil.

A swap transaction can consist of various payments made or received such as periodic payments, up front payments, or termination payments. A periodic payment is generally based upon an interest rate or index factor multiplied by a notional principal amount. An up front payment can be an agreed upon lump sum payment such as a premium paid to enter into a swap contract.  A termination payment is a payment made or received to terminate or assign the rights of a swap contract.

## Forward Market

The forward market is where oil is bought and sold between two parties with the delivery of the commodity to be consummated at a future date.  This type of transaction does not take place through a commodity exchange.  Forward contracts are the vehicle used in this market.

### Forward Contracts

Commodity futures and forward contracts were originally developed as a tool to hedge business inventory.  A forward contract is used to acquire an agreed upon item at a specified price with delivery at a future date.  A forward contract is defined as the following:

> "Any contract that is entered into between two parties for delivery of specified property at a future date and that is not traded on an exchange or board of trade."

A crude oil producer incurs fixed costs to operate and maintain wells and related equipment such as labor to operate the wells and related equipment, repairs and maintenance, materials, supplies, and property taxes.  The producer has a risk that the market price of crude oil might fall by the time it is ready to deliver.  In order to reduce this risk, the producer can enter into a forward contract by which the crude oil is sold at a high price ensuring a profit in exchange for delivery of the oil at a future date.  A manufacturer of oil such as a refiner might need a supply of crude oil and want to purchase the oil at a low price.  To ensure an adequate supply, the refiner may enter into a contract to buy crude oil at a low price with future delivery.  Oil producers and refiners are acting as hedgers when utilizing forward contracts to reduce their inventory risks.

Forward contracts currently are entered into in a wide variety of financial products in the marketplace, such as foreign currency contracts, government securities, debt instruments, and even stock.

## Futures Market

There are two markets in the energy futures: New York Mercantile Exchange (NYMEX) and International Petroleum Exchange (IPE). Both exchanges trade futures contracts and options on futures contracts.

Energy futures and options on futures are closely related, but are not interchangeable. Each has its own advantages and disadvantages and can be used in various ways for risk management or investment purposes. The level of risk in futures trading differs from options trading. The risk in purchasing an options contract is limited to the premium paid while the risk of trading futures is much greater. Margin deposits are required on futures transactions. While no deposit is imposed upon purchasing an options contract, margin is required upon writing an options contract.

Below is a chart that reflects the types of futures contracts and sizes that are handled by NYMEX and IPE.

**Exchange Traded Energy Futures**

| Futures Contract | Contract Size | Minimum Fluctuation |
|---|---|---|
| NYMEX: | | |
| Crude Oil | 1,000 Barrels (42,000 Gallons) | 1 Cent/Barrel = $10 |
| No. 2 Heating Oil | 42,000 Gallons | 1/100 cents/gal = $4.20 |
| Unleaded Gasoline | 42,000 Gallons | 1/100 cents/gal = $4.20 |
| Propane | 42,000 Gallons | 1/100 cents/gal = $4.20 |
| IPE: | | |
| Gas Oil | 100 Metric Tons | U.S. 25 cents/ton = $25 |
| Heavy Fuel Oil | 100 Metric Tons | U.S. 25 cents/ton = $25 |
| Premium Leaded Gasoline | 100 Metric Tons | U.S. 25 cents/ton = $25 |
| Crude Oil | 1,000 Barrels | U.S. 1 cent/barrel = $10 |

**Futures Contracts**

Energy futures began trading on NYMEX in 1978 and the IPE was established in April of 1981. A commodity exchange does not buy or sell futures contracts, it only provides a facility for its members to buy and sell contracts for their own account and for the accounts of public customers. Contracts are traded in an exchange by members through an auction system of open outcries of competitive bid (buy) and ask (sell) prices. Domestic futures exchanges are regulated by the CFTC.

A futures contract is a forward contract that is traded on an exchange or board of trade. It is defined as a "bilateral contract to buy or sell a fixed quantity of a specified commodity at a stated price with delivery to take place on a specified date in the future and that is traded on an exchange."

A buyer of a futures contract agrees to accept delivery of the underlying commodity while a seller agrees to make delivery. The majority of futures contracts are closed through an offsetting buy or sell position of an identical futures contract, a contract for the same commodity with the same delivery date. Therefore, a delivery of the commodity does not take place. The price of a futures contract reflects the market's consensus regarding the expected price of a commodity in the future relative to supply and demand for that commodity.

To open and maintain a commodity account with a brokerage firm, margin must be deposited in the account. Margin is a performance bond which acts as collateral for the purpose of insuring a broker that the account will have sufficient funds to cover potential losses. Brokerage firms compute each clients total account equity on a daily basis by computing the unrealized gains and losses on open positions (termed mark to market) plus the realized gains and losses and cash deposited. If the account has a debit balance, a margin call for more money will be made.

**Futures Transaction.** Straddles are a common investment strategy used by many people to take advantage of price differences between the buy and sell positions. The straddle is also known as "balanced positions." It is where one is buying and selling simultaneously on or near the same trade date of either the same commodity or related commodity.

The following are examples of straddles.

A crude oil refiner entered into the following crude oil futures contracts on the NYMEX:

| Trade Date | Position | Contracts | Delivery Date | Total Price |
|---|---|---|---|---|
| 08-01-89 | Sell | [40] | July | $2,000.00 |
| 08-01-89 | Buy | 40 | March | (1,951,000) |
| | | | | |
| 08-04-89 | Buy | 40 | May | (1,851,000) |
| 08-04-89 | Sell | [40] | March | 2,825,000 |
| | | | | |
| 02-18-90 | Sell | [40] | May | 2,025,000 |
| 02-18-90 | Buy | 40 | July | (2,051,000) |

There is an equilibrium effect with a straddle. For example, when the price of a commodity increases, there is a potential gain in the buy position and a potential offsetting loss in the sell position.

**Options Contracts**

Options trading in the energy futures started in 1986 with trading done by NYMEX. It was introduced to provide different hedging or investment alternatives and to meet the needs of the market participants. It appears that options add increased flexibility to hedging and other trading programs. Today options on energy futures contracts are traded on the NYMEX and IPE.

An option is a unilateral contract conveying the right to buy and sell a specific item at a specified price within a specified period of time. The underlying property in an option contract can be any type of property such as real estate, stock, or futures.

Below is a chart that reflects the type of options contract and size that are handled by NYMEX and IPE.

**Exchange Traded Energy Options**

| Underlying Futures Contract | Contract Size | Strike Price Increments | Minimum Fluctuation |
|---|---|---|---|
| NYMEX: | | | |
| Crude Oil | 1,000 Barrels (42,000 Gallons) | $1/Barrel | 1 Cent/Barrel = $10 |
| Heating Oil | 42,000 Gallons | 2 Cents/Gallon | 1/100 Cents/Gallon = $4.20 |
| IPE: | | | |
| Gas Oil | 100 Metric Tons | $5/Ton | 5 Cents/Ton = $5 |

**Basic Types of Options**

There are two types of options that are traded: a call and a put. A call option is a contract that entitles the purchaser to the right to buy the underlying futures contract at a specific price within a specified period of time. A put option is the opposite of a call; it entitles the purchaser to the right to sell the underlying futures contract at a specific price within a specified period of time. A call and a put are separate, distinct vehicles that are used for different strategies and purposes.

The exercise price, also known as the strike price, is the price at which an option holder may buy or sell the futures contract.

The last day on which an option can be exercised is termed the expiration date. If an option has not been exercised prior to the specified expiration date, it expires and ceases to exist. That is, the option buyer no longer has any rights; therefore, the option no longer has any value.

The purchaser of an option pays a premium for the right to acquire the option. An option premium does not constitute a down payment. The premium is simply a fully non-refundable payment for the rights conveyed by the option. It is the price of the option.

**Parties in an Option**

There are always two parties in an options contract. They are the option purchaser and the option writer.

The option purchaser (buyer) is the individual who purchases the option. The option purchaser is also referred to as the "holder." The purchaser pays a premium to obtain the right to buy or sell the specified property at a certain price. Only the option purchaser has the right to exercise an option. The purchaser of a call option pays a premium for the right to buy the underlying property. The purchaser of a put option pays a premium for the right to sell the underlying property.

The second party to an options contract is the option writer also referred to as the "seller" or the "grantor" of the option. The option writer receives the premium and is obligated to sell the underlying property at the specified price if the option buyer chooses to exercise the call. The writer of a put option receives a premium and is obligated to buy the underlying property at a specified price if the option buyer chooses to exercise the option. For every call option traded, there is a call purchaser and a call writer (seller), and for every put option traded there is a put purchaser and a put writer (seller).

**Opening and Closing Transactions**

The initial purchase or sale transaction that results in an individual becoming a purchaser or writer of an option is termed the opening transaction. A closing transaction cancels out an investor's previous position as the purchaser or the writer of an option. Examples of closing transactions are where the purchaser of an option enters into an offsetting sale of an identical option, or the writer of an option makes an offsetting purchase of an identical option.

**Termination of an Options Contract**

**Option Purchaser.** There are three ways in which an option purchaser can terminate an options position. They are as follows:

1. Do nothing and allow the call or put option to expire. The purchaser incurs a loss equal to the option premium paid.

2. Exercise the option.

   Upon exercise, a call purchaser takes delivery of the underlying futures contract and pays the exercise price. A call writer would be assigned the obligation to sell; the assignment would be conducted through an options exchange.

   Upon exercise, a put purchaser is obligated to make delivery of the underlying futures contract and receives the exercise price.

3. Enter into a closing transaction, also termed an offsetting position.

   The purchaser of a call closes the position by selling the same option series that contains the same expiration date and exercise price.

   The purchaser of a put closes the position by buying the same option series.

**Option Writer.** There are three ways that an option writer's obligation can terminate. They are as follows:

1. A put or call option may lapse without being exercised by purchaser. The writer recognizes income in the amount of premium received.

2. A put or call option may be exercised by the purchaser.

   The writer of a call that is exercised must deliver the underlying futures contract in exchange for the exercise price.

   The writer of a put that is exercised must pay the exercise price and receives the underlying futures contract.

3. An option writer may enter into a closing transaction (offsetting position).

## Market Participants in Forward and Futures Contracts

As stated previously, the oil marketplace consists of the cash market, the forward market, and the futures market. According to an article in the *Oil and Gas Investor*, June 1988, participants in the marketplace include refiners, producers, marketers, consumers, and speculators. Amoco, Arco, Chevron, Mobil, Murphy Oil, Royal Dutch/Shell, Mesa Petroleum Co., Marathon, and Diamond Shamrock R&M were acknowledged as trading futures contracts on the NYMEX. Investment banking firms have also traded on the NYMEX such as J. Aron & Co., Inc., Drexel Trading of Drexel Burnham Lambert, Morgan Stanley, and Bear Stearns. The investment bankers are traders and have no intention of actually owning any oil. Another participant is the floor trader that is a member of the NYMEX trading for his or her own account. The article stated, "These traders do not care whether the market is pork bellies or frozen orange juice. It's all the same to them if the price in whatever they're trading is going up or down."

### Speculators

Hedgers, such as producers and manufacturers, are not necessarily going to buy and sell futures or forward contracts at the same time. Someone who trades contracts and is not a hedger is known as a speculator. A speculator trades for his or her own account for a profit. The speculator provides a liquid marketplace for the hedger. Most exchange members are not hedgers, but merely speculators seeking a profit from trading for their own account. Speculators can include investors and traders.

### Hedgers

The definition of the word hedge is the reduction of risk. The term hedge or hedger is commonly used to refer to financial transactions because such transactions are entered into to reduce one's risk. A tax hedge is a financial transaction in futures or forward contracts entered into by a dealer to reduce the risk of holding inventory. For tax purposes, a hedge transaction must meet certain judicial and legislative criteria which was established in *Arkansas Best v. Commissioner*, 485 U.S. 212 (1988) and IRC section 1256(e) to receive ordinary loss treatment. In addition to the court case, examiners should consult Temp. Treas. Reg. section 1.1221-2T and Treas. Reg. section 1.1221-2(c)(2), (c)(4), and (c)(5)(ii) for further guidance as to hedging transactions. The temporary regulation section set out above is applicable to hedging transactions entered into on or after January 1, 1994, or entered into on or before that date and remain into existence on March 31, 1994.

If an examiner has a "hedging" issue, a financial products specialist should be contacted for assistance. After contacting the specialist, it could be determined that a referral may be in order.

### Investor

One who trades for potential profit for its own account is considered to be an investor. An investor can trade energy forward or futures contracts for various reasons such as long term appreciation or short term profits. An investor can be someone who has no direct interest in oil. However, it can also be an entity involved in the oil industry that enters into contracts for profit speculation separate and apart from hedging its business inventory. The financial transactions of an investor generally give rise to capital gains or losses.

### Trader

A trader is someone who trades futures or forward contracts on a regular basis for its own account. One must meet certain judicial requirements established in *King v. Commissioner*, 89 T.C. 1214 (1988), to be considered a trader for tax purposes. A trader is in a trade or business of trading for his or her own account. The financial transactions of a trader give rise to ordinary gain or loss treatment and the related expenses are deductible under IRC section 162 as trade or business expenses. A member of the NYMEX who trades futures for his or her own account as a floor trader is a trader for tax purposes.

## COMMODITY NOTIONAL CONTRACTS

### Commodity Notional Swap

In a commodity notional swap, one party agrees to pay the spot price of the commodity at specified intervals for a notional amount of the commodity. In return it receives a fixed price based on the same notional amount of the commodity for a specified period of time. The notional amount of the commodity on which the payments are based is not exchanged between the parties. Most commodity notional swaps are based on oil and other energy related products.

### Use of Commodity Notional Swap to Hedge Risk

For example, an oil producer seeking a stable price for its oil sales can use a commodity notional swap to lock in prices by paying the spot (market) price under the swap in return for a fixed payment (for example, $20 for each notional barrel of oil). The spot price the producer will receive when it sells the physical commodity in the marketplace will offset the payment of the spot price under the swap contract.

The net effect of the swap and the sale of the physical commodity together is that the producer receives a fixed payment of $20 per barrel of oil sold.

Though the oil producer has fixed its income stream, it will not benefit if oil prices increase to $25. The producer will receive more from the sale of oil, but it owes payments to its swap counterparty based on the higher spot price. Thus, swaps not only hedge the downside, they also give up the upside.

## GLOSSARY

There are many terms that are synonymous with the oil and gas industry. Below are terms that are encountered when examining an oil and gas entity or activity. Even though some of the terms are not discussed or used in this audit techniques guide, this glossary will be helpful to you as they will be encountered sometime during an examination.

**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.

**ACIDIZE**: Increase the flow of oil from a well by introducing acid into a limestone formation to open passages through which oil can flow into the well bore.

**ACQUISITION WELL**: A well drilled in exchange for a mineral interest in a property. It is also referred to as an obligation well.

**ACRE-FOOT**: A reservoir analysis measure of volume. One acre foot represents the volume which would cover one acre to a depth of one foot.

**ADVANCED ROYALTY**: An advance payment made by the owner of an operating interest to the royalty owner for a specific number of units of minerals regardless of whether oil or gas was extracted within the year. The payment is recoverable out of future production.

**AFE**: Authorization for expenditures. It is a form used during the planning process for a well about to be drilled. It can also be used for other projects. The form includes an estimate of costs to be incurred in the intangible drilling costs (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.

**AIR DRILLING**: The use of compressed air as a substitute for drilling mud in rotary drilling.

**AIR/GAS LIFT**: Method of raising oil from the formation by injecting air or gas directly into the fluid in the casing.

**ALLOWABLE**: The regulated amount of oil or gas that a well or lease can produce during a given time period.

**ANTICLINES**: Underground mountain-shaped strata covered with caprock or an impervious layer.

**API**: Abbreviation for American Petroleum Institute, established in 1920.

**API GRAVITY**: Liquid petroleum product measure of gravity of the product. Derived from a formula using specific gravity.

**APPORTIONMENT ACCOUNTS**: Accounts used to accumulate expenses during a period, with the accounts being credited for amounts charged to activities on some predetermined basis.

**ASSOCIATED GAS**: Natural gas, occurring in the form of a gas cap, overlying an oil zone.

**BAFFLES**: 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.

**BATTERY**: Group of lease storage tanks.

**BEAM**: The horizontal portion of an "I" beam pumping unit.

**BEAM WELL**: A well from which oil is lifted by using a pumping unit and sucker rods and pump.

**BLOWOUT**: Strong flow of oil or gas, uncontrolled, from a reservoir to the surface and into the atmosphere.

**BOILERHOUSE**: A slang term. "Fake" a report without having performed any work.

**BONUS**: The consideration received by the lessor or sublessor on execution of the oil or gas lease.

**BOTTOM HOLE CONTRIBUTIONS**: Money or property given to an operator for their use in drilling a well on property in which the payor has no property interest. The contribution is payable when the well reaches a predetermined depth, regardless of whether the well is productive or nonproductive. Usually, the payor receives geological data from the well.

**BOTTOM HOLE PRESSURE**: The pressure at the bottom of a well in the producing formation.

**BRITISH THERMAL UNIT (BTU)**: A measure of the amount of heat required to raise the temperature of one pound of water one degree Fahrenheit.

**BS OR BS&W**: An abbreviation for basic sediment, or basic sediment and water. BS&W is produced along with oil.

**CARRIED INTEREST**: A sharing arrangement in which one party agrees to pay the cost incurred on behalf of another which is the carried party. After production begins, the carried party receives no income until the carrying party has recouped all of their costs incurred on behalf of the carried party.

**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**: An interest that occurs when the owner of a working interest assigns it to another as an overriding royalty, net profits interest, or production payment.

**CARVED-OUT OIL OR GAS PAYMENT**: A payment in oil or gas assigned by the owner of a working interest or fee interest. The payment is expressed in dollars, in barrels, in MCF, or as a period of time, to be paid out of a fractional part of the fee interest or working interest. The payment will run for a period shorter than the life of the interest from which it was carved.

**CASINGHEAD GAS**: Gas produced along with crude oil from oil wells.

**CASING PRESSURE**: Gas pressure in a well that is built up between the casing and tubing or casing and drill pipe.

**CATHEAD**: A spool shaped device attached to a winch around which rope is wound for hoisting and pulling.

**CATLINE**: A hoisting or pulling line powered by a cathead; lifts equipment around the rig.

**CAT WALK**: The narrow walkway on a drilling rig or on top of a tank battery.

**CELLAR**: An excavation under the rig floor to provide space for working equipment during drilling.

**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. Generally, this is done to spread the risk or to make sure the producer will have some ownership if production is found.

**CHRISTMAS TREE**: A term applied to the valves and fittings assembled at the top of a well to control the flow of oil.

**CLEAN OUT COSTS**: Costs incurred to clean out a well to maintain its productive capacity or to restore it to original capacity. For example, the cost of removing sand and tubing or opening the pores in the producing formations.

**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. (See also APPORTIONMENT ACCOUNTS.)

**COMPLETION**: Refers to the work performed and the installation of permanent equipment for the production of oil or gas from a recently drilled well.

**CONDENSATE**: A light hydrocarbon liquid which is in a gaseous state in the reservoir but which becomes liquid at the surface.

**CONNATE WATER**: Water originally in the producing formation.

**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.

**COST CEILING**: The limit placed on the "carrying value" of mineral assets in the cost center.

**COST CENTER**: The geological, geographical, or legal unit with which costs and revenues are identified and accumulated. Examples are the lease, the field country, etc.

**CROSS SECTION MAPPING**: Maps of cross-section of underground formation.

**CRUDE OIL**: Liquid petroleum after being produced but before being refined.

**DAILY DRILLING REPORT**: Twenty-four hourly report indicating all important events which occurred on a drilling rig.

**DAMAGE PAYMENTS**: Payments made to the landowner by the oil or gas operator for damages to the surface, to the 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 amount of money per day will be paid to the drilling contractor until a well is drilled to an agreed upon depth.

**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. It is also known as an "Installment Bonus."

**DELAY RENTALS**: These are amounts paid to the lessor for the privilege of deferring the commencement of a well on the lease. Oil and gas lease agreements generally provide a deadline for the lessee to begin drilling of the lease. If the drilling has not begun within this period of time, either the lease agreement will expire or the lessee must pay a stated sum of money to retain the lease an additional year without developing the property.

**DELINEATION WELL**: A well to define, or delineate, the boundaries of the reservoir.

**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 on the amount of gross income from the property.

**DETAILED SURVEY**: An intensive geological and geophysical exploration of an area of interest.

**DEVELOPMENT WELL**: A well drilled within the proved area of an oil or gas reservoir to the depth of a horizon known to be productive.

**DEVIATED WELL**: A well drilled at an angle from the vertical.

**DIRECTIONAL DRILLING**: Intentionally drilling a well at an angle from the vertical.

**DISPOSAL WELL**: A well through which salt water is pumped to subsurface reservoirs.

**DISSOLVED GAS**: Natural gas mixed with crude oil in a producing formation.

**DIVISION ORDER**: A document that describes the economic interest owners of a property and the types of interest owned. It is used by the purchaser as the basis for paying each economic interest owner their share of revenue.

**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.

**DRY GAS**: Natural gas composed of vapors without liquids and which tends not to liquefy.

**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 payors have no property interest. Such contributions are payable only in the event the well reaches an agreed depth and is found to be dry.

**ECONOMIC INTEREST**: An economic interest is possessed in every case in which the taxpayer has acquired by investment any interest in mineral in place and secures, by any form of legal relationship, income derived from the extraction of the mineral to which one must look for a return on the capital.

**ENHANCED RECOVERY**: Any methods used to extract oil from reservoirs in excess of that which may be produced through primary recovery.

**EXPLOITATION ENGINEERING**: Engineering related to subsurface geology, the recovery of fluids from reservoirs, and the drilling and development of oil 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.

**EXPLORATION RIGHTS**:  Permission granted by landowners allowing others to enter upon their property for the purposes of conducting geological and geophysical surveys.

**EXPLORATORY WELL**:  All wells drilled to search for or produce oil or gas except the cost of development wells and development type stratigraphic test wells drilled to gain access to proved reserves.

**FARM-IN**:  An agreement in which a person agrees to drill one or more wells in exchange for receiving a working interest from the person holding the lease.

**FARMOUT**:  An agreement in which the person holding a lease assigns a working interest in the property to another in exchange for drilling one or more wells.

**FAULTS**:  The breaks in strata resulting from significant moving or shifting of the earth's surface.

**FEE INTEREST**:  Ownership of both mineral and surface rights on a tract of land.  Also called fee simple.

**FIELD**:  An area consisting of a reservoir or multiple reservoirs related to the same geological structural feature.  Reservoirs in overlapping or adjacent fields may be treated as a single operational field.

**FIELD EXPLORATORY WELL**:  A well drilled in an area where there was previous production, but outside the limits of the known reserves.  It is also known as a delineation well.

**FIELD FACILITY**:  Oil and gas production equipment serving more than one lease.  For example, separator, extraction unit, etc.

**FIELD PROCESSING**:  Treating oil or gas before it is delivered to a gas plant or refinery.

**FIRE WALL**:  An earthen dike built around an oil tank to contain the petroleum if the tank ruptures.

**FLOW CHART**:  A record of the production of gas measured by a meter.

**FLOWING WELL**:  A well which lifts oil and gas to the surface with natural reservoir pressure.

**FLOW LINES**:  The surface pipes through which oil moves from the well to the lease tank.

**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.

**FLUID INJECTION**: Inducing gas or liquid into a reservoir to move oil toward the well bore.

**FLUSH PRODUCTION**: The large flow of production initially made by a well 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.

**FORMATION PRESSURE**: Bottom hole pressure of a shut-in well.

**FRACTURING**: A procedure to stimulate production by forcing under high pressure a mixture of oil and sand into the formation.

**FREE WELL AGREEMENT**: A form of sharing arrangement in which one party drills one or more wells completely free of cost to a second party in return for one type of economic interest in property.

**FULL COSTING**: A concept under which all costs incurred in searching for, acquiring, and developing oil and gas reserves are capitalized.

**GEOLOGICAL and GEOPHYSICAL (G & G)**: Surveys of a topographical, geological, and geophysical nature along with other costs incurred to obtain the rights to make these surveys, and salaries and other expenses of the personnel required to carry out the surveys are often referred to as "G & G" costs.

**GAS OIL RATIO**: A measure of the volume of gas produced along with oil from the same well.

**GAS INJECTION**: Gas is injected into a formation to maintain pressure or for secondary recovery. Reproduced injected gas cannot usually be distinguished from the original formation gas.

**GAS LIFT GAS**: Gas injected into the well bore to lift the oil to surface. Gas lift gas, unlike injected gas, returns immediately to the mouth of the well without entering the reservoir. Normally, the sales price for recovered gas lift gas is lower.

**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.

**GAS WELL**: A well producing natural gas.

**GATHERING LINES**: A small pipeline which moves the oil from several wells into a single tank battery or major pipeline.

**GAUGE TICKET**: A form on which the measurement of oil in lease tanks is recorded.

**GRAVITY**: A standard American Petroleum Industry (API) scale which is related to specific gravity of a petroleum fluid based on a technical formula. On this scale the greater the density of the petroleum, the lower the API degree. The higher the API gravity, the greater the value of the oil.

**GRAVITY METER**: An instrument measuring the variations in the gravitational pull.

**HORIZON**: An underground geological formation which is the portion of the larger formation which has sufficient porosity and permeability to constitute a reservoir.

**HORIZONTAL ASSIGNMENT**: An assignment of an interest in the minerals above or below or between specified depths, or in a given stratum or horizon.

**HYDROCARBON**: An organic compound of hydrogen and carbon.

**INDEPENDENT PRODUCER**: It is defined in IRC section 613A(d) as a producer who does not have more than $5 million in retail sales of oil or gas in a year and who does not refine more than 50,000 barrels of crude on any day during the year. An exemption from the denial of percentage depletion is provided in IRC section 613A(a) for independent producers if production is within the limits of the average daily production of oil and gas set in IRC section 613A(c).

**INTANGIBLE DRILLING COSTS (IDC)**: 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.

**INJECTION OR INPUT WELLS**: A well used to inject gas, water, or liquid petroleum gas (LPG) under high pressure into a producing formation to maintain sufficient pressure to produce the recoverable reserves.

**IN SITU 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.

**ISOPACH MAPS**: Maps showing variations in the thickness of a particular sedimentary bed and also can show the interval or spacing between one bed and another.

**JOINT**: A single length of drill pipe, casing, etc. usually from 20 to 30 feet in length.

**JOINT INTEREST AUDIT**: An audit performed by or on behalf of the non-operator working interest owners to determine if the operator is conforming to the provisions of the operating agreement and accepted accounting procedures.

**JOINT INTEREST or JOINT VENTURE**: An association of two or more persons or companies to drill, develop, and operate jointly properties. Each owner has an undivided interest in the properties.

**KILL A WELL**: To bring high well pressure under control by the use of mud or water so that the well may be completed, etc.

**LACT UNIT (LEASE AUTOMATIC CUSTODY TRANSFER UNIT)**: A unit which is used to account for purchases of oil. The LACT unit automatically transfers the oil, records the information, and prepares the run ticket.

**LANDMAN**: A person experienced in mineral leasing activities.

**LEASE AGREEMENT**: An agreement between two or more parties by which a lessee is given the right to enter a property, survey and locate a well site, perform drilling operations, and remove any minerals found.

**LEASE BONUS**: The consideration paid by the lessee to the lessor for executing the lease.

**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.

**LESSEE**: The person who leases the mineral rights from the owner in order to drill and operate wells.

**LESSOR**: The person who owns the mineral rights and has executed a lease.

**LIFTING COST**: All customary expenses incurred in connection with the production and marketing of oil and gas.

**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.

**MARGINAL WELL**: A well whose production is so limited that it is no longer profitable to operate.

**MCF**: Thousands of cubic feet of natural gas.

**METAMORPHIC ROCKS**: Rocks developed as a result of being subjected to heat and pressure.

**MINIMUM ROYALTY**: An obligation of a lessee to periodically pay the lessor a fixed 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 FLUID**: A secondary recovery process which involves the injection of a mixture of hydrocarbons which displaces fluid.

**MMCF**: Millions of cubic feet of natural gas.

**MOBILE DRILLING RIG**: A drilling rig used offshore. It floats from one drill site to another. Drill ships, jack-ups, and semi-submersibles are mobile rigs.

**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 more than one reservoir.

**NATURAL GAS**: Hydrocarbons that exist in the gaseous phase under certain atmospheric and temperature conditions.

**NATURAL GAS LIQUIDS**: Hydrocarbons which can be extracted from natural gas.

**NET PROFITS INTEREST**: This is an interest carved out of the working interest. It is a nonoperating interest that shares in the net profits, if any, but has no liability for capital investments or losses.

**NEW FIELD WILDCAT**: A well drilled in an area where previously there had been no production of oil or gas.

**NONASSOCIATED GAS**: Natural gas not in contact with reservoirs that contain significant quantities of crude oil.

**NONCONTINUING INTEREST**: An interest in a mineral property whose life is limited in terms of dollars, units of production, or time.

**NONOPERATING INTEREST**: An interest in an oil or gas property that bears no costs of development or operation, such as the landowner's royalty interest.

**NONOPERATING WORKING INTEREST**: A working interest owner that does not participate in the day-to-day operations of developing and operating a mineral interest.

**OFFSET**: Drilling a well adjacent to another.

**OFFSET WELL**: Well drilled on one tract of land to prevent drainage of oil or gas to a nearby tract on which a well has been drilled.

**OIL PAYMENT**: A production payment payable out of oil produced.

**OIL POOL**: An underground reservoir containing oil in the sedimentary rocks.

**OIL SAND**: Any porous reservoir containing oil.

**OIL SEEP**: Areas where tiny amounts of petroleum have migrated to the surface.

**OIL WELL**: A well that is being pumped because it will not flow.

**OPERATOR**: One who holds the working or operating rights and is obligated for the costs of development and production, either as a fee owner or as an assignee.

**OPERATING WORKING INTEREST**: A working interest owner who participates in the day-to-day operations of developing and operating the mineral interest.

**OPERATING INTEREST**: See Working Interest.

**OUTPOST WELL**: A well drilled in an attempt to make a long extension of a producing pool; a well located outside the established reservoir boundaries.

**OVERRIDING ROYALTY INTEREST**: This is an interest carved out of the working interest which does not require the owner to bear a share of the developing or operating cost. It exists only for a stipulated time, but never longer than the life of the working interest. It is a nonoperating 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. It is also known as "Statutory Depletion."

**PERFORATE**: To penetrate the well casing with holes made with a perforating gun.

**PERMEABILITY**: The porosity of a given formation providing oil with the ability to flow.

**PIG**: A scraping instrument for cleaning a pipeline.

**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.

**POROSITY**: The condition of a formation which permits oil to flow.

**POSTED PRICE**: The price published and circulated between buyers and sellers in a particular field.

**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 field.

**PRIMARY RECOVERY**: Oil which is forced into the well bore by natural reservoir pressure.

**PRIMARY TERM**: The maximum period of time allowed by a lease for the lessee to commence drilling a well. Drilling cannot be deferred beyond the primary term, even by the payment of delay rentals.

**PRODUCE**: For purposes of IRC section 263A, it includes construct, build, install, develop, manufacture, improve, create, raise or grow.

**PRODUCER**: A generic term used to refer to all economic interest holders in a property.

**PRODUCTION PAYMENT**: A right to minerals in place which entitles its owner to a specific fraction of production for a limited period of time, or until a specific sum of money or a specific number of units of mineral has been received.

**PRODUCTION TAXES**: Taxes levied by state governments on mineral production based upon the value and/or quantity of production. They are also known as 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**: Each separate interest owned by a taxpayer in each mineral deposit in each separate tract or parcel of land. Certain interests may be combined to form a property. See IRC section 614 for the "codified" definition of property.

**PRORATION**: A system of allocating production from a well permitted to be produced during a period of time.

**PROSPECT**: A lease or a group of leases on which an owner proposes to drill one or more wells.

**PROVED DEVELOPED RESERVES**: Reserves which can be expected to be recovered through existing wells with existing equipment and operating methods.

**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.

**PROVED UNDEVELOPED RESERVES**: Reserves which are expected to be recovered from new wells on undrilled proved acreage, or from existing wells where a relatively major expenditure is required for completion.

**PROVEN PROPERTIES**: A property whose principal value has been demonstrated by exploration, discovery, or development.

**PUT ON A PUMP**: To install a pump jack or pumping unit, sucker rods, and bottom hole sucker rod jump.

**PUT ON A WELL**: To begin a well flowing or pumping.

**RABBIT**: Line cleaning instrument. A small plug which is run through a line.

**RECONNAISSANCE SURVEY**: A survey of a project area utilizing various geological and geophysical techniques to identify specific geological features with sufficient mineral producing potential to merit further exploration.

**RETAINED INTEREST**: The interest created when the owner sells the working interest and retains an overriding royalty, a net profits interest, or a production payment. An owner can retain the working interest and sell the others.

**REMIT SLIP**: Check stub from payee of oil and or gas. It will usually indicate barrels or MCF, gross revenue or net revenue, and the amount actually paid.

**ROYALTY INTEREST**: An ownership interest that entitles its owner to share in the production from the mineral deposit, free of development and operating costs, and extends undiminished over the productive life of the property. It is a nonoperating interest.

**RUN TICKET**: A document, prepared by the purchaser's gauger and witnessed by the lease pumper, which records the quantity of oil removed, its gravity, temperature, and impurities (Basic Sediment & Water or BS&W).

**SEISMOGRAPH**: The instrument used to record the refraction of sound waves.

**SERVICE WELL**: A well drilled for the purpose of supporting production; for example, a gas injection well or a water injection well.

**SPOT PRICE**: A short-term price negotiated between the buyer and the seller.

**SPUD IN**: To start drilling a well.

**STEP OUT WELL**: A well drilled adjacent to a proved well in an attempt to determine the limits of the reservoir.

**STRATIGRAPHIC TEST WELL**: A well drilled to obtain information about geologic conditions. This well is common for offshore drilling. Stratigraphic test wells are classified as follows: (1) Exploratory-type stratigraphic test well (a stratigraphic test well not drilled in a proved area) and (2) Development-type stratigraphic test well (a stratigraphic test well drilled in a proved area).

**STRIP WELL**: To pull both the rods and tubing from a well simultaneously.

**STRIPPER**: A well nearing the end of its productive life; very little oil is being produced.

**STRUCTURAL MAPS**: Maps that indicate subsurface features.

**SWAB**: A device that fits tightly inside the tubing; when pulled through the tubing, it lifts fluid.

**SWEET OIL (OR GAS)**: Oil or gas without sour impurities.

**TAKE OR PAY CONTRACTS**: An agreement in which a purchaser of gas agrees to take a minimum quantity of gas per year if one is not prevented from doing so by circumstances beyond his or her control and if the gas is available for delivery. If the purchaser does not take the minimum quantity, he or she is required to pay for that minimum quantity at the contract price; normally, one may make up deficiency amounts in future years if he or she purchases in excess of minimum amounts.

**TANGIBLE ASSETS**: The cost of assets that in themselves have a salvage value.

**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 1/4 (one-quarter) inch intervals.

**TERTIARY RECOVERY**: The use of sophisticated techniques such as flooding the reservoir with chemicals to increase the production of oil or gas.

**THIEF**: A device for extracting oil samples from a tank.

**TOP LEASE**: A new lease obtained covering a property currently leased before the expiration of the previous lease between the same parties.

**TRUNCATION TRAPS**: Traps associated with noncomformities or discontinuities in the strata.

**TURNKEY WELL**: A completed well, drilled and equipped by a contractor for a fixed price.

**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 the production from all the properties on a stipulated percentage or fractional basis regardless of from which property the oil or gas is produced.  All owners of economic interests in the properties should be involved in the agreement.

**VISCOSITY**:  The ability of a fluid to flow as a result of its physical characteristics.

**WATERFLOODING**:  A method of secondary recovery in which water is injected into an oil reservoir for the purpose of pushing the oil out of the reservoir rock and into the bore of a producing well.

**WATER WELL**:  A well drilled to obtain a supply of water for drilling or operating use.

**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.

**WET GAS**:  Gas that contains a large quantity of liquids.

**WORKING INTEREST**:  An interest which entitles the owner to share in the production and requires the owner to bear its share of the developing and operating cost.  This is also known as an operating interest.  The life of the working interest is tied to the lease.  If the lease is terminated the working interest associated with the lease terminates.

**WORKOVER COSTS**:  Expenses incurred in cleaning a well in an attempt to increase production.

**ZONE**:  A stratigraphic interval containing one or more reservoirs.

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*Blake v. Commissioner*, 20 T.C. 721 (1953)

Depletion on Lease Bonus
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*Glenn v. Commissioner*, 39 T.C. 427 (1962)

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*Producers Chemical Co, v. Commissioner,* 50 T.C. 940
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*Killam v. Commissioner*, 39 T.C. 680 (1963)

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*Larsen v. Commissioner*, 66 T.C. 478 (1976)

**REVENUE RULINGS**

| | REVENUE RULING NO. |
|---|---|
| **Assignments, Sales and Exchanges** | |
| Acquisition and Option Fees | 80-176, 1980-2 CB 97 |
| Assignment for Cash at Less Than Equipment Basis | 55-35, 1955-1 CB 286 |
| Fee Paid for Services Rendered | 77-395, 1977-2 CB 80<br>71-191, 1971-1 CB 77<br>67-141, 1967-1 CB 153 |
| Fees Paid by Investors | 83-137, 1983-2 CB 41 |
| Management Fee | 81-150, 1981-1 CB 119 |
| Natural Gas Sold After Removal From Premises — Less Than Representative Market Field Price (RMFP) | 90-62, 1990-2 CB 158 |
| Property Sale With Zero Basis | 75-451, 1975-2 CB 330 |
| Sale of Interest — Ordinary Income or Capital Gain | 73-428, 1973-2 CB 303<br>66-226, 1966-2 CB 239 |
| **Capital Expenditures** | |
| Depreciation on Well Equipment | 78-13, 1978-1 CB 63 |
| Drilling Cost Deductible If Arm's Length | 73-211, 1973-1 CB 303 |
| Drilling Cost for Injection Wells — Primary Development | 69-583, 1969-2 CB 41 |
| Drilling Cost Incurred Outside United States | 73-470, 1973-2 CB 88<br>67-34, 1967-1 CB 72 |

| | |
|---|---|
| Drilling Cost Paid for Production Payment Twice Cost | 75-446, 1975-2 CB 95 |
| Drilling Cost Paid In Turnkey Agreement | 75-304, 1975-2 CB 94 |
| Drilling Cost With Right to Income During Payout | 69-332, 1969-1 CB 87 |
| Drilling Cost — Partnership Allocation | 68-139, 1968-1 CB 311 |
| Drilling Cost — Underground Storage | 75-235, 1975-1 CB 97 |
| Drilling Cost — Taxpayer's Permanent Fractional Share | 71-206, 1971-1 CB 105<br>70-336, 1970-1 CB 145 |
| Drilling Cost — 200 Percent Recoup Then Working Interest Terminates | 71-207, 1971-1 CB 160 |
| Drilling to Acquire an Interest | 70-657, 1970-2 CB 70 |
| Drilling to Acquire Site and Acreage | 77-176, 1977-1 CB 77 |
| Easements — Underground Storage | 75-234, 1975-1 CB 96 |
| Geological and Geophysical Costs | 77-188, 1977-1 CB 76 |
| Installation of Production Facilities | 70-414, 1970-2 CB 132 |
| Lease Acquisition — First Year Rental | 69-467, 1969-2 CB 142<br>67-25, 1969-1 CB 156<br>56-252, 1956-1 CB 210 |
| LPG Injected Into Oil Recovery Process | 73-469, 1973-2 CB 85<br>70-354, 1970-2 CB 50 |
| Offshore Platforms, Onshore Fabrication Cost | 70-596, 1970-2 CB 68 |
| Partial Release of Lease | 68-78, 1968-1 CB 294 |
| Prepaid Drilling Cost | 71-579, 1971-2 CB 225<br>71-252, 1971-1 CB 146 |

**Definition of Property**



**Cost Depletion**



**Depletion, Gross Income, Net Income**

| | REVENUE RULING NO. |
|---|---|
| Contract to Purchase Natural Gas | 68-330, 1968-1 CB 291 |
| Cost Well | 80-342, 1980-2 CB 99 |
| Deduction of Loss | 54-581, 1954-2 CB 112 |
| Depreciation of Lessor's Equipment | 68-361, 1968-2 CB 264 |
| Foreign Tax Credit | 75-427, 1975-2 CB 296 |
| Gas Compression Cost | 75-6, 1975-1 CB 178 |
| Gas Consumed in Manufacturing Process | 68-665, 1968-2 CB 280 |
| Geothermal Wells | 85-10, 1985-1 CB 181 |
| Market or Field Price | 77-33, 1977-1 CB 165 |
| Net Operating Loss | 69-355, 1969-1 CB 65 |
| Net Profit Interest | 73-541, 1973-2 CB 206 |
| Nonproducing Activities | 56-433, 1956-2 CB 332 |
| Nonproductive Well IDC | 77-136, 1977-1 CB 167 |
| Oil Removed But Not Currently Sold | 76-533, 1976-2 CB 189 |
| Prepaid IDC | 71-579, 1971-2 CB 225 |
| Retailer Exclusion | 85-12, 1985-1 CB 181 |
| Sales Commissions | 60-98, 1960-1 CB 252 |
| State and Federal Gasoline Tax Credit | 66-266, 1966-2 CB 239 |
| "Take Or Pay" Payments | 80-48, 1980-1 CB 99 |
| Tax or Book | 83-134, 1983-2 CB 103 |
| Taxes Paid by Lessee | 72-165, 1972-1 CB 177 |
| Transfers of Proven Property | 83-167, 1983-2 CB 104 |

### Percentage Depletion

| | |
|---|---|
| Net Profits Interest | 92-25, 1992-1 CB 196 |
| Retailer's Exclusion | 92-72, 1992-2 CB 118 |

### Geological and Geophysical Costs

| | |
|---|---|
| Tax Treatment of G&G | 77-188, 1977-1 CB 76<br>83-105, 1983-2 CB 51 |

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|---|---|
| 200 Percent Reversion Then Working Interest Terminates | 75-4461, 1975-2 CB 95 |
| Allocation of Lump-Sum Payment — IDC and Leasehold | 73-211, 1973-1 CB 303 |
| Consolidated Returns | 69-590, 1969-2 CB 170 |
| Depreciation — Underground Storage | 75-235, 1975-1 CB 97 |
| Downhole Equipment | 78-13, 1978-1 CB 63 |
| Drilling for Interest | 71-207, 1971-1 CB 160<br>71-206, 1971-1 CB 105<br>70-657, 1970-2 CB 70 |
| Drilling to Acquire Site Plus Acreage | 77-176, 1977-1 CB 77 |
| Easement — Underground Storage | 75-234, 1975-1 CB 96 |
| Expense Recognition | 71-252, 1971-1 CB 146 |
| Farm-In of Two Properties | 80-109, 1980-1 CB 129 |
| Foreign Properties | 87-134, 1987-2 CB 69<br>73-470, 1973-2 CB 88<br>67-34, 1967-1 CB 72 |

**Nonconventional Fuel Credit**

**Nonrecourse Loan**

| | |
|---|---|
| Acquisition Cost of Property | 78-29, 1978-1 CB 62 |
| Advanced Royalties | 80-73, 1980-1 CB 128 |

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| | |
|---|---|
| Distributive Share | 68-139, 1968-1 CB 311 |
| Limited Partnership | 80-71, 1980-1 CB 106 |

**Sharing Arrangements**

| | |
|---|---|
| 100 Percent Working Interest Until ½ Recoupment Then 1/4 Interest | 71-206, 1971-1 CB 105 |
| Depreciable Equipment Treated After Drilling Cost Recouped | 71-207, 1971-1 CB 160<br>69-332, 1969-1 CB 87 |
| Drilling for an Interest | 70-657, 1970-2 CB 70 |
| Drilling for Site and Acreage | 77-176, 1971-1 CB 77 |
| Drilling in a Partnership | 54-42, 1954-1 CB 64 |
| Lessee Uses Lessor's Equipment | 68-361, 1968-2 CB 264 |
| Partnership | 68-139, 1968-1 CB 311 |
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