Minerals Revenue Management

Transmittal Sheet

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In Release 2.1 of the *Oil and Gas Payor Handbook, Volume III—Product Valuation*, we updated the Web site addresses for the Royalty Management Program (RMP), which is now the Minerals Revenue Management (MRM). Our new Web site address is www.mrm.mms.gov. No other changes were made, and copies of Release 2.0 may still be used.

Connie Bartram [original signature on file]

Acting Manager, Regulations and FOIA Team

Filing instructions:

Replace pages 3-1, 4-1, A-2, and Release History-1 with the updated pages.

Oil and Gas Payor Handbook, Volume III Product Valuation

Royalty Management Program

U.S. Department of the Interior
Minerals Management Service
Royalty Management Program

Oil and Gas Payor Handbook, Volume III Product Valuation

Royalty Management Program

MMS/RMP Release 2.0

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U.S. Department of the Interior
Minerals Management Service
Royalty Management Program

Abbreviations

AFS	Auditing and Financial System
AID	accounting identification
API	American Petroleum Institute
bbl	barrel
BIA	Bureau of Indian Affairs
BLM	Bureau of Land Management
Btu	British thermal unit
BTU/ft^3	British thermal units per cubic foot
CA	communitization agreement
CFR	*Code of Federal Regulations*
CO_2	carbon dioxide
DOI	Department of the Interior
FERC	Federal Energy Regulatory Commission
FR	*Federal Register*
GPM	gallons per thousand cubic feet
H_2S	hydrogen sulfide
IBLA	Interior Board of Land Appeals
ID	identification
Mcf	thousand cubic feet of gas
MLP	maximum lawful price
MMBtu	million British thermal units
MMS	Minerals Management Service
NGL	natural gas liquid
NGLP	natural gas liquid products
NGPA	Natural Gas Policy Act of 1978
NPSL	net profit share lease
NTL	Notice to Lessees
OCS	Outer Continental Shelf
OCSLA	Outer Continental Shelf Lands Act

PA	participating area
PAAS	Production Accounting and Auditing System
PIF	Payor Information Form
POP	percentage of proceeds
psia	pounds per square inch, absolute
PVR	plant volume reduction
RIK	royalty-in-kind
RMP	Royalty Management Program
ROI	return on investment
S	sulfur
TC	transaction code
U.S.C.	*United States Code of Law*

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1. Introduction

The Minerals Management Service (MMS), Royalty Management Program (RMP), within the Department of the Interior (DOI), is responsible for ensuring that all revenues from Federal and Indian mineral leases are properly collected, accounted for, and disbursed to the appropriate recipients. RMP also provides technical support for lease management functions.

To effectively fulfill its responsibilities, MMS uses two comprehensive, integrated accounting systems:

- Auditing and Financial System (AFS), and
- Production Accounting and Auditing System (PAAS).

AFS is a revenue accounting system that accounts for royalties and related information from payors. PAAS is a production accounting system that monitors production and disposition activity on mineral lease sites. Although MMS uses both systems, this handbook addresses only transportation and processing allowance and royalty valuation procedures for reporting royalties to AFS.

Royalties are based on the amount or value of production removed or sold from the lease. To clarify and detail royalty valuation procedures for Federal and Indian oil and gas production, MMS issued new royalty valuation regulations at Title 30, *Code of Federal Regulations* (CFR) Parts 202 and 206, effective March 1, 1988. Each lessee is responsible for the proper valuation, for royalty purposes, of Federal and Indian production.

1.1 Organization of the Payor Handbook Series

The *Oil and Gas Payor Handbook, Volume III—Product Valuation* provides detailed royalty valuation procedures for Federal and Indian oil and gas production, and information on establishing and reporting processing and transportation allowances. This volume also provides examples for determining the value of production for royalty purposes and completing transportation and processing allowance forms.

The payor handbook series also includes the following handbooks:

- The *Oil and Gas Payor Handbook, Volume I—Payor Information Form (Form MMS-4025)* contains an overview of the MMS reporting structure; describes the Payor Information Form (PIF), Form MMS-4025, for oil, gas, and other products; and provides detailed instructions for completing the PIF.
- The *Oil and Gas Payor Handbook, Volume II—Report of Sales and Royalty Remittance (Form MMS-2014)* contains detailed instructions, by transaction code, for completing Form MMS-2014.
- The *Solid Minerals Payor Handbook* provides detailed instructions for solid minerals reporting.

All of the handbooks contain instructions and numerous examples to assist payors in preparing the required forms. For questions on specific forms or procedures, lessees should consult the handbook applicable to that topic.

1.2 Organization of Volume III

Volume III is divided into the following chapters:

Chapter 2, "Valuation Overview," describes general valuation provisions, including several subjects generally common to both oil and gas.

Chapter 3, "Oil Valuation," describes the methods and procedures for valuing oil produced from Federal and Indian lands.

Chapter 4, "Gas Valuation," describes specific methods and procedures for valuing gas and constituent products. The chapter is further divided into procedures for valuing unprocessed and processed gas.

Chapter 5, "Oil Transportation Allowances," explains the procedures for calculating and reporting transportation allowances for Federal and Indian oil, condensate, and other liquid production.

Chapter 6, "Gas Transportation Allowances," describes the procedures for calculating and reporting transportation allowances for Federal and Indian unprocessed gas, residue gas, and gas plant products.

Chapter 7, "Gas Processing Allowances," explains the procedures for calculating and reporting allowances for processing gas produced from Federal and Indian leases.

In each chapter, MMS provides pertinent regulations citations after the explanation of that regulation; for example, "The lessee may not deduct actual or theoretical losses of volume from the royalty volume or the royalty value of production (30 CFR 206.103(b) and (e))." Where applicable, statutes or legal decisions are also cited. To aid the reader, the following table shows which regulations apply to what products. For text locations of citations included in this volume, see "Citations and References Index."

TABLE 1-1. *Cross-reference of products and regulations*

Product	Regulation	
Part 202—Royalties		
Subpart B—Oil, Gas, and OCS Sulfur, General	202.51–.53	
Subpart C—Federal and Indian Oil	202.100–.101	
Subpart D—Federal and Indian Gas	202.150–.153	
Part 206—Product Valuation		
Subpart B—Indian Oil	206.50–.53 206.54–.55	Valuation Allowances
Subpart C—Federal Oil	206.100–.103 206.104–.106	Valuation Allowances
Subpart D—Federal Gas	206.150–.155 206.156–.160	Valuation Allowances
Subpart E—Indian Gas	206.170–.175 206.176–.179	Valuation Allowances

1.3 Terminology

Specialized terms are used throughout Volume III; for example, "arm's-length contracts," "gross proceeds," and "marketing affiliate." Lessees must be familiar with the definitions of such terms to fully understand and properly use the valuation principles in this handbook. Lessees should refer to regulations at 30 CFR 206.101 (oil) and 30 CFR 206.151 (gas) for definitions of specialized terms used in this handbook.

1.4 Handbook Distribution

MMS is responsible for distribution of the *Oil and Gas Payor Handbook* volumes. One copy of the handbook and any revisions are provided to the lessee at no cost. However, MMS charges a fee for all copies of instructional handbooks provided to lessees on Federal or Indian leases in excess of one copy per valid and active payor code. Companies with multiple payor codes that have the same name and address will receive only one copy free of charge. Copies requested by other interested parties or additional copies requested by lessees will be provided for a fee to recover the administrative costs associated with printing and mailing. Notice was published in the *Federal Register* (FR) on September 24, 1992 (57 FR 44208).

Requests for additional copies may be mailed to the following address:

Minerals Management Service
Royalty Management Program
Accounting and Reports Division
P.O. Box 25165, Mail Stop 3130
Denver, CO 80217-0165

You may also order additional hardcopy handbooks by calling the RMP handbook order line at 303-231-3105.

The handbook is also available online on MMS's Web site at www.mms.gov.

1.5 Handbook Maintenance

MMS periodically issues revisions to the *Oil and Gas Payor Handbook*. A release history is included with each update. Handbook users are responsible for adding or replacing pages according to the instructions on the transmittal sheet.

MMS/RMP recommends that reporters and payors keep superseded releases of MMS handbooks for their use in future reviews of transactions that occurred and were reported while the release was in effect.

1.6 Important Addresses and Phone Numbers

For your convenience, we have developed a quick-reference table showing what group within MMS to contact with your questions or to send forms and requests to.

TABLE 1-2. ***Address and phone number quick-reference table***

Circumstance	Contact number	Address: When using U.S. Postal Service	Address: When using courier, express delivery, or overnight delivery service
• To ask questions about the valuation of production. • To request valuation guidance. • To ask questions about how to determine transportation and processing allowances. • To apply for allowance exceptions.	Phone: 303-275-7201 Fax: 303-275-7227	Minerals Management Service Royalty Management Program Royalty Valuation Division P.O. Box 25165, Mail Stop 3150 Denver, CO 80225-0165	Minerals Management Service Royalty Management Program Royalty Valuation Division 12600 W. Colfax Ave., Suite C-100 Lakewood, CO 80215
• To submit transportation allowance Forms MMS-4110 (oil) and MMS-4295 (gas) and processing allowance Form MMS-4109 (gas) for Indian leases. • To apply for an extension to file forms or an exception to the 3-month retroactive period for Indian leases. • To ask questions regarding allowance forms for Indian leases. • To submit arm's-length gas transportation and processing contracts.	Phone: 303-275-7459 Fax: 303-275-7470	Minerals Management Service Royalty Management Program State and Indian Compliance Division P.O. Box 25165, Mail Stop 3660 Denver, CO 80225-0165	Minerals Management Service Royalty Management Program State and Indian Compliance Division 12600 West Colfax Avenue Suite B-200 Lakewood, CO 80215
• To ask questions regarding the Payor Information Forms, contact the Accounting and Reports Division.	Phone: 1-800-525-9167 Fax: 303-231-3107	Minerals Management Service Royalty Management Program Accounting and Reports Division P.O. Box 5760 Denver, CO 80217-5760	
• To ask questions about the Monthly Report of Operations, Form MMS-3160 or the Oil and Gas Operations Report, Form MMS-4054, contact the Production Error Correction Section. • To ask questions about the Report of Sales and Royalty Remittance, Form MMS-2014, contact the Royalty Error Correction Section.	Phone: 1-800-525-7922 Fax: 303-231-3135 Phone: 1-800-525-0309 Fax: 303-231-3700	Minerals Management Service Royalty Management Program, Accounting and Reports Division P.O. Box 17110 Denver, CO 80217-0110	Minerals Management Service Royalty Management Program Room A-212, Document Processing Section Building 85, Denver Federal Center Denver, CO 80225

2. Valuation Overview

The mineral leasing laws require that the lessor receive a royalty on the volume or value of production removed or sold from Federal or Indian lands.

The valuation standards and procedures described in this handbook apply to Federal and Indian oil and gas production beginning March 1, 1988, concurrent with the effective date of the new oil and gas royalty valuation regulations. With few exceptions, these regulations supersede all oil and gas royalty valuation directives contained in numerous Secretarial, MMS, and U.S. Geological Survey Conservation Division orders, directives, regulations, and Notices to Lessees (NTLs) issued prior to the effective date of the new valuation regulations.

2.1 Applicable Leases and Lands

As specified in 30 CFR 202.51(a), leases and lands to which these guidelines apply include the following:

Federal

- Onshore producing oil and gas leases on public domain or acquired lands, regardless of which Federal agency administers the surface activities.
- All Outer Continental Shelf (OCS) leases.
- Federal lands subject to compensatory royalty agreements when such agreements specify that the value be determined under 30 CFR 206.
- Any other contract, profit-share arrangement, joint venture, or other agreement issued or approved by the United States under a mineral-leasing law that authorizes exploration for, development or extraction of, or removal of the lease products (30 CFR 206.101 and 30 CFR 206.151).

Indian

- Producing oil and gas leases, permits, or contracts on Indian Tribal and allotted lands.

Indian (continued)

- Indian lands subject to compensatory royalty agreements when such agreements specify that the value be determined under 30 CFR 206.
- Any other contract, profit-share arrangement, joint venture, or other agreement issued or approved by the Bureau of Indian Affairs (BIA), individual Tribes, or allottees under a mineral-leasing law that authorizes exploration for, development or extraction of, or removal of the lease products (30 CFR 206.51 and 30 CFR 206.171).

These guidelines do not apply to leases on the Osage Indian Reservation, Osage County, Oklahoma, and to certain leases and/or lands that are subject to privately issued leases that were in effect at the time the leases and/or lands were acquired by the Federal Government, such as lands acquired by the Federal Farm Mortgage Corporation. However, if the terms of those leases specify that value be determined under 30 CFR 206, these guidelines apply.

2.2 Production Requiring Royalty Valuation

Royalty valuation procedures described in this handbook and in 30 CFR 202 and 30 CFR 206 apply to all Federal and Indian oil and gas production that is:

- Removed or sold from the lease,
- Avoidably lost,
- Wasted,
- Drained, or
- Otherwise subject to royalty under the terms of the lease.

In all the above situations, **value is established at the time of production**.

Certain volumes of production may be royalty-free if authorized by the terms of the lease. These volumes usually include production used on or for the benefit of the lease (such as for fuel or pressure maintenance) and unavoidably lost production. Although such production is not subject to royalty, the volumes must be reported to either AFS or PAAS for accounting purposes. However, if the production is actually sold before being used on the lease, such production is royalty-bearing (Petro-Lewis Corp., Interior Board of Land Appeals (IBLA), 108 IBLA 20, March 20, 1989).

2.3 Precedence of Lease Terms, Statutes, Treaties, Court Decisions, and Settlement Agreements

In most cases, the valuation standards and procedures described in this handbook apply equally to both Federal and Indian production. However, most Indian leases, certain OCS leases, and leases not initially issued by DOI may contain special valuation requirements. Lease terms may also be modified by unitization or communitization agreements. In those cases where the valuation regulations are inconsistent with the valuation provisions in the lease, the lease terms, including those that have been modified by subsequent agreements, govern the valuation to the extent appropriate (30 CFR 202.100(b)(3) and 30 CFR 202.150(b)(3)).

For instance, certain leases issued under Section 6 of the Outer Continental Shelf Lands Act (OCSLA) of 1953, as amended, do not contain provisions allowing beneficial use of lease production free of royalty. Certain leases issued on military lands contain clauses specifically prohibiting the deduction of transportation and processing allowances. The actual terms of these leases take precedence over the applicable regulations.

Specific provisions of statutes, treaties, or settlement agreements between the United States (or Indian lessor) and a lessee resulting from administrative proceedings or judicial litigation also take precedence over the valuation regulations where inconsistencies occur (30 CFR §§ 206.50(b), 206.100(b), 206.150(b), and 206.170(b)). This primacy rule is extended to court orders and legal decisions resolving valuation issues.

2.4 Quantities and Qualities

This section describes how the quantities and qualities of production are determined for royalty purposes. Standards discussed in this section apply to all royalty-bearing products, including oil, condensate, unprocessed gas, residue gas, gas plant products, and other products.

The value of oil or gas removed or sold from a lease is based on the quantity and quality of production measured at the point of royalty settlement (30 CFR §§ 206.53(a)(1), 206.103(a)(1), 206.154(a)(1), and 206.174(a)(1)). The point of royalty settlement is the physical location where production in marketable condition is measured for royalty purposes. The point of royalty settlement is determined by the Bureau of Land Management (BLM) for onshore production and MMS for offshore production.

Royalty is due on the production measured at the point of royalty settlement, regardless of whether that production is subsequently sold. For instance, if gas is removed from a lease or unitization or communitization agreement area and is stored off the lease or agreement area in an underground gas storage reservoir without first being sold, royalty is due at the time the gas is removed from the lease or agreement area, not at the time the gas is removed from storage and ultimately sold.

In situations where gas is processed, royalty is due on the net output (quantity) of residue gas and gas plant products measured at the tailgate of the plant and attributable to the lease (30 CFR 206.154(b)(1) and 30 CFR 206.174(b)(1)).

2.4.1 Reporting standards

The lessee must report the quantity (volume) and quality of production using the units of measurement specified at 30 CFR 202.101 for oil and 30 CFR 202.152 for gas. Refer to those sections of the regulations for specific requirements.

Gas volumes and British thermal unit (Btu) heating values must be determined under the same degree of water saturation and must be reported on the same water vapor basis (saturated or unsaturated) prescribed by Federal Energy Regulatory Commission (FERC) regulations, or on the basis prescribed in the lessee's sales contract, provided the sales contract does not conflict with FERC regulations. Thus, if a sales measurement is based on conditions other than those prescribed by regulation, the measurement must be adjusted to reflect the prescribed conditions for reporting and value calculation purposes.

Figure 2-1 illustrates the conversions necessary to value gas sold on a dry (unsaturated) basis when FERC requires measurement on a wet (saturated) basis.

2.4.2 Adjustments for quantity and quality

If the lessee's sales price or value of production is based on a quantity or quality different from that measured at the point of royalty settlement, the value must be adjusted to compensate for any differences (30 CFR §§ 206.53(a)(2), 206.103(a)(2), 206.154(a)(2), 206.154(b)(2), and 206.174(a)(2)).

For instance, if a lessee's gross proceeds from the sale of gas are based on a volume measured at a point other than the approved point of royalty settlement and that volume is less than the volume measured at the approved point of royalty settlement, then the gross proceeds for royalty purposes must be increased to reflect the higher volume measured at the approved point of royalty settlement.

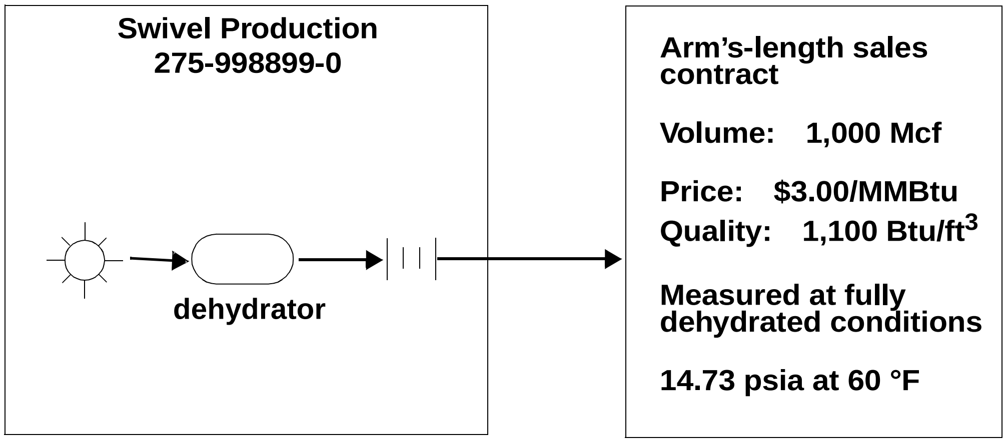
Figure 2-2 illustrates valuation of lease gas when the quantity and quality of production measured at the royalty settlement point are different from those measured at the sales point.

2.4.3 Actual or theoretical losses

The lessee may not deduct actual or theoretical losses of volume from the royalty volume or the royalty value of production, except under certain conditions (30 CFR §§ 206.53 (b) and (c), 206.103(b) and (c), 206.154(d), and 206.174(d)). **Royalty is due on 100 percent of the volume measured at the point of royalty settlement**.

Lessees are not required to report losses that occur prior to the point of royalty settlement if BLM (onshore) or MMS (offshore) determines such losses are unavoidable.

If losses are part of an arm's-length transportation contract or a FERC-approved or State regulatory agency-approved tariff, such losses may be deducted as part of the transportation allowance (see Chapter 5, "Oil Transportation Allowances," or Chapter 6, "Gas Transportation Allowances").



FERC has established a maximum lawful price for this gas of $3.00/MMBtu. However, FERC rules require that the gas is assumed to be saturated (wet).

Value for royalty purposes is calculated by converting the Btu content of the dry gas to a wet gas basis:

<u>Conversion factor (based on FERC's standard conditions as required in Order 93-A, 18 CFR 270.204):</u>

$$\textbf{1,000 Btu/ft}^3\textbf{ (dry)} = \textbf{982.6 Btu/ft}^3\textbf{ (wet)}$$

Dry (sales) gas converted to wet gas basis:

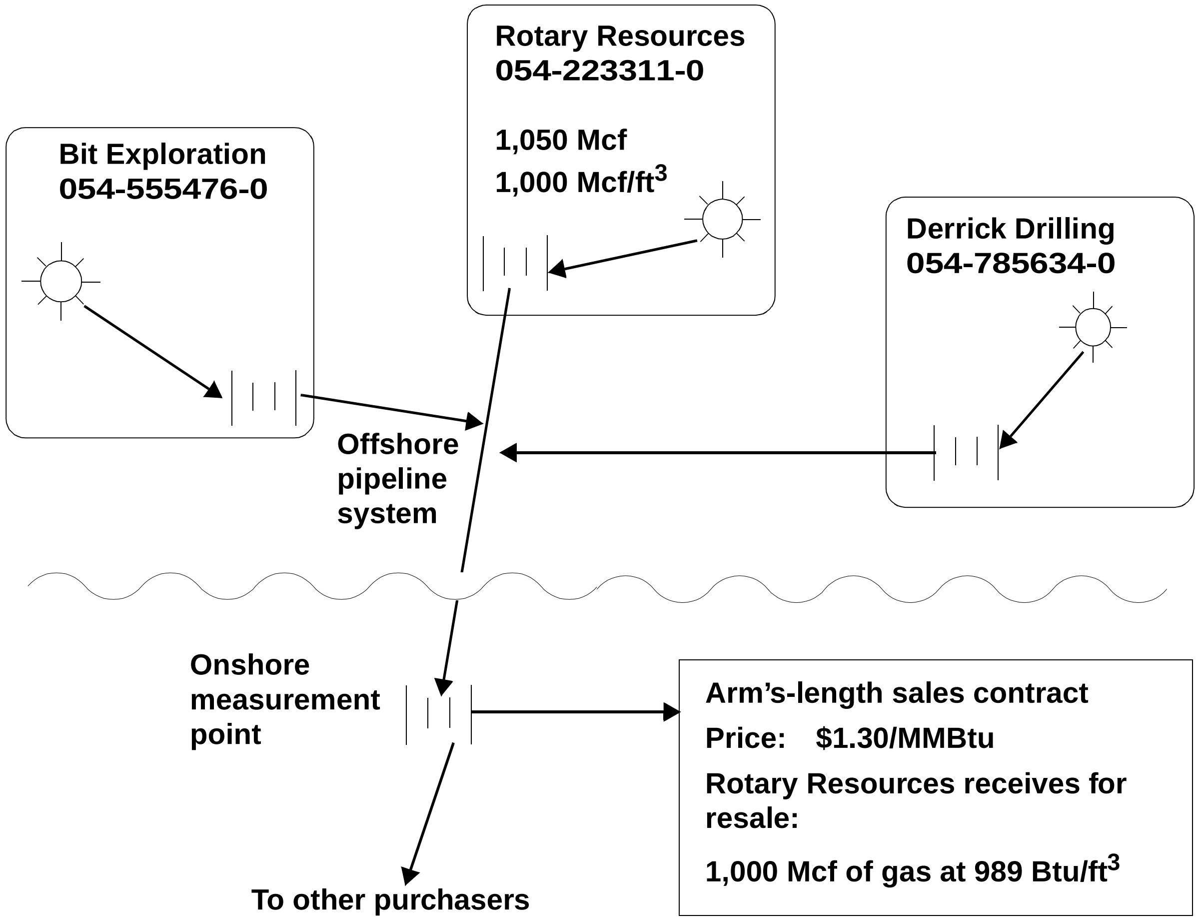
$$1,100\,\text{Btu/ft}^3\text{ (dry)} \times \frac{982.6\text{ Btu/ft}^3}{1,000\text{ Btu/ft}^3} = 1,080.9\text{ Btu/ft}^3\text{ (wet)}$$

Calculation of value:

$$1,080.9\text{ Btu/ft}^3 \times 1,000\text{ ft}^3\text{/Mcf} \times \frac{1\text{ MMBtu}}{1,000,000\text{ Btu}} \times 1,000\text{ Mcf}$$

$$\times\,\$3.00\text{/MMBtu} = \$3,242.70$$

FIGURE 2-1. Conversion of measured heat content from a dry basis to a wet basis and resulting value calculation



Rotary Resources is required to report royalties based on quantity and quality of production measured at the royalty meter at the platform.

The value for royalty purposes for production from this lease is calculated as follows:

$$1,050\ \text{Mcf} \times 1.0\ \text{MMBtu/Mcf} \times \$1.30/\text{MMBtu} = \$1,365.00$$

FIGURE 2-2. Adjustments to royalty value based on the quantity and quality of production measured at the approved point of royalty settlement

2.4.4 Quantity determinations for processed gas and gas plant products

When gas is processed for the recovery of residue gas and gas plant products, a portion of the net plant output is allocated to each lease supplying production to the plant. The specific allocation procedure depends on whether the plant processes gas of uniform content or nonuniform content.

When the net plant output is derived from gas produced from a single lease, the quantity and quality of residue gas and gas plant products attributable to the lease are simply the net plant output. However, gas from multiple leases supplying the plant frequently contains diverse amounts of hydrocarbons and/or nonhydrocarbon substances. In these situations, the allocation must be based on the theoretical or tested volume of residue gas and gas plant products contained in the gas at the lease.

The theoretical volumes of residue gas and gas plant products contained in the gas stream at the lease (V_{TL}) are usually determined by periodic testing. Common testing methods include gas chromatography and charcoal and compression analyses.

The test volume of residue gas is expressed in mole percent of the total wet gas volume. The test volume of natural gas liquids (NGLs) is expressed in gallons per thousand cubic feet (GPM) of the total wet gas volume. If gas plant products other than NGLs are present, such as carbon dioxide (CO_2) or sulfur (S), the test volumes of these products are also expressed in mole percent of the total wet gas volume.

The royalty quantity of residue gas and gas plant products is the monthly output of the plant, even though these components may be placed in temporary storage.

2.4.4.1 Plant output derived from multiple leases with uniform gas content

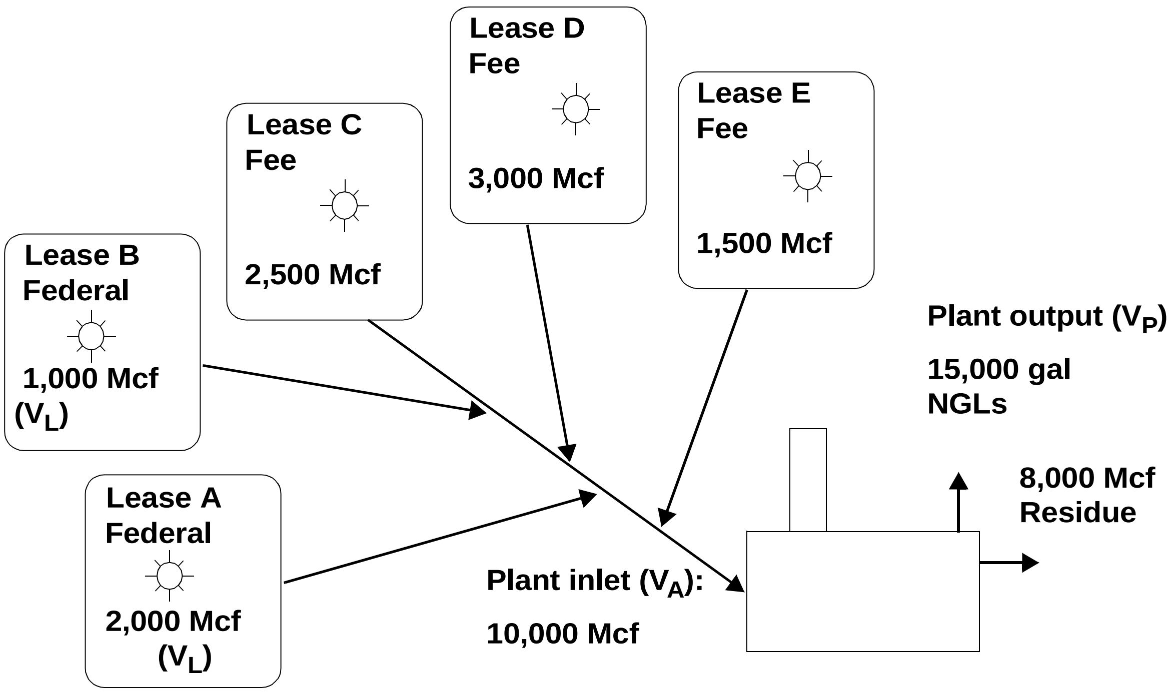
If all of the leases supplying the plant produce gas of uniform content (that is, gas of similar Btu content and chemical composition), the theoretical quantities of residue gas and gas plant products allocated to the lease (V_T) are based on the relative volumes of gas delivered to the plant. These quantities are calculated by multiplying the volume of the plant output of residue gas and gas plant products (V_P) by the ratio of the volume of gas and gas plant products delivered from each lease (V_L) to the volume of gas and gas plant products delivered from all leases (V_A) (30 CFR 206.154(c)(2) and 30 CFR 206.174(c)(2)). The general equation for calculating these quantities is:

$$V_T = V_P \times \frac{V_L}{V_A}$$

This calculation must be performed separately for residue gas, NGLs, and other gas plant products (if appropriate).

Figure 2-3 illustrates the procedure for allocating net plant output back to individual leases that supply gas of uniform content to a processing plant.

Five leases supply gas of uniform content to the Big River Gas Processing plant.



The volume of residue gas and NGLs allocated to Federal leases A and B based on the net plant outlet are:

Residue gas (V_T)

Lease A: $$8,000 \text{ Mcf} \times \frac{2,000 \text{ Mcf}}{10,000 \text{ Mcf}} = 1,600 \text{ Mcf}$$

Lease B: $$8,000 \text{ Mcf} \times \frac{1,000 \text{ Mcf}}{10,000 \text{ Mcf}} = 800 \text{ Mcf}$$

NGLs (V_T)

Lease A: $$15,000 \text{ gal} \times \frac{2,000 \text{ Mcf}}{10,000 \text{ Mcf}} = 3,000 \text{ gal}$$

Lease B: $$15,000 \text{ gal} \times \frac{1,000 \text{ Mcf}}{10,000 \text{ Mcf}} = 1,500 \text{ gal}$$

FIGURE 2-3. Allocation of net plant output to leases supplying gas of uniform content to a gas processing plant

2.4.4.2 Plant output derived from multiple leases with nonuniform gas content

For plant outputs derived from leases supplying gas of nonuniform content (that is, the Btu content and chemical compositions of the gas from each lease are different), the volumes of residue gas and gas plant products allocable to each lease are based on the theoretical volumes of residue gas and gas plant products measured in the lease gas stream. To calculate the portion of net plant output of residue gas and gas plant products attributable to each lease, the lessee must perform the following three steps:

STEP 1. Determine the theoretical volumes of residue gas and gas plant products delivered from each lease.

The theoretical volumes of residue gas and gas plant products (NGLs and other gas plant products) delivered from each lease (V_{RL}, V_{NL}, V_{GL}) are computed by multiplying the lease volume of the gas stream (measured at the point of royalty settlement) by the tested residue gas content or gas plant product content of the gas stream.

The following general equations are used to compute the theoretical volumes of residue gas and gas plant products delivered from a lease:

Residue gas

$$V_{RL} = \text{lease volume x mole \% of residue gas at the lease}$$

NGLs

$$V_{RL} = \text{lease volume x GPM of ethane, propane, butane, etc. at the lease}$$

Other gas plant products

$$V_{GL} = \text{lease volume} \times \text{mole \% of } CO_2\text{, S, etc., at the lease}$$

STEP 2. Determine the theoretical volume of residue gas and gas plant products delivered from all leases.

The theoretical volume of residue gas and gas plant products delivered from all leases (V_{RA}, V_{NA}, and V_{GA}) is calculated by summing the theoretical volumes of residue gas and gas plant products delivered from each lease:

Residue gas

$$V_{RA} = V_{RL1} + V_{RL2} + V_{RL3...}$$

NGLs

$$V_{NA} = V_{NL1} + V_{NL2} + V_{NL3...}$$

Other gas plant products

$$V_{GA} = V_{GL1} + V_{GL2} + V_{GL3...}$$

STEP 3. Determine the portion of net plant output of residue gas and gas plant products that is attributable to each lease.

The theoretical quantities of net plant output of residue gas and gas plant products attributable to each lease (V_{RT}, V_{NT}, V_{GT}) are calculated by multiplying the net plant output of residue gas and gas plant products (V_{RP}, V_{NP}, V_{GP}) by the ratio of the theoretical volume of residue gas and gas plant products delivered from each lease (from step 1) to the theoretical volume of residue gas and gas plant products delivered from all leases (from step 2). The following three equations show how the net plant output of residue gas and gas plant products is allocated back to each lease.

Residue gas

$$V_{RT} = V_{RP} \times \frac{V_{RL}}{V_{RA}}$$

NGLs

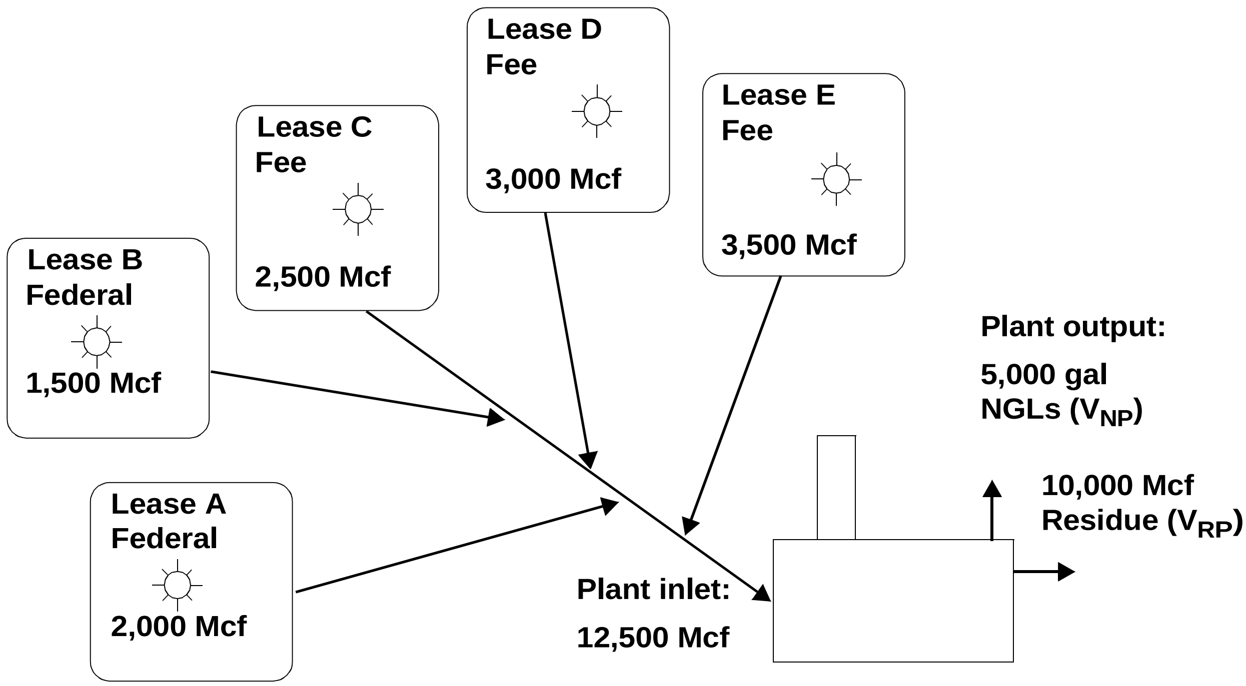
$$V_{NT} = V_{NP} \times \frac{V_{NL}}{V_{NA}}$$

Other gas plant products

$$V_{GT} = V_{GP} \times \frac{V_{GL}}{V_{GA}}$$

Figure 2-4 illustrates the allocation of net plant output back to individual leases that supply gas of nonuniform content to a processing plant.

Five leases supply gas of nonuniform content to the Table Mesa Gas Processing Plant.



Test residue gas and NGLs contents measured for each lease are:

	Residue gas content (mole %)	NGLs content (GPM)
Lease A:	95	0.25
Lease B:	90	0.35
Lease C:	85	0.45
Lease D:	80	0.60
Lease E:	75	0.70

The theoretical volumes of residue gas available from each lease (V_{RL}) are:

Lease A:	V_{RL1}	=	2,000 Mcf	×	0.95	=	1,900 Mcf
Lease B:	V_{RL2}	=	1,500 Mcf	×	0.90	=	1,350 Mcf
Lease C:	V_{RL3}	=	2,500 Mcf	×	0.85	=	2,125 Mcf
Lease D:	V_{RL4}	=	3,000 Mcf	×	0.80	=	2,400 Mcf
Lease E:	V_{RL5}	=	3,500 Mcf	×	0.75	=	2,625 Mcf

FIGURE 2-4. Allocation of net plant output to leases supplying gas of nonuniform content to a gas processing plant (1 of 2)

The theoretical volume of residue gas available from all leases (V_{RA}) is:

$$1,900 \text{ Mcf} + 1,350 \text{ Mcf} + 2,125 \text{ Mcf} + 2,400 \text{ Mcf} + 2,625 \text{ Mcf}$$
$$= 10,400 \text{ Mcf}$$

The theoretical volumes of NGLs available from each lease (V_{NL}) are:

Lease A:	V_{NL1}	=	2,000 Mcf	×	0.25 GPM	=	500 gal
Lease B:	V_{NL2}	=	1,500 Mcf	×	0.35 GPM	=	525 gal
Lease C:	V_{NL3}	=	2,500 Mcf	×	0.45 GPM	=	1,125 gal
Lease D:	V_{NL4}	=	3,000 Mcf	×	0.60 GPM	=	1,800 gal
Lease E:	V_{NL5}	=	3,500 Mcf	×	0.70 GPM	=	2,450 gal

The theoretical volume of NGLs available from all leases (V_{NA}) is:

$$500 \text{ gal} + 525 \text{ gal} + 1,125 \text{ gal} + 1,800 \text{ gal} + 2,450 \text{ gal} = 6,400 \text{ gal}$$

The theoretical volumes of reside gas and NGLs allocated to leases A and B based on the net plant output are:

Residue gas (V_{RT})

Lease A: $$10,000 \text{ Mcf} \times \frac{1,900 \text{ Mcf}}{10,400 \text{ Mcf}} = 1,827 \text{ Mcf}$$

Lease B: $$10,000 \text{ Mcf} \times \frac{1,350 \text{ Mcf}}{10,400 \text{ Mcf}} = 1,298 \text{ Mcf}$$

NGLs (V_{NT})

Lease A: $$5,000 \text{ gallons} \times \frac{500 \text{ gal}}{6,400 \text{ gal}} = 391 \text{ gal}$$

Lease B: $$5,000 \text{ gallons} \times \frac{525 \text{ gal}}{6,400 \text{ gal}} = 410 \text{ gal}$$

FIGURE 2-4. Allocation of net plant output to leases supplying gas of nonuniform content to a gas processing plant (2 of 2)

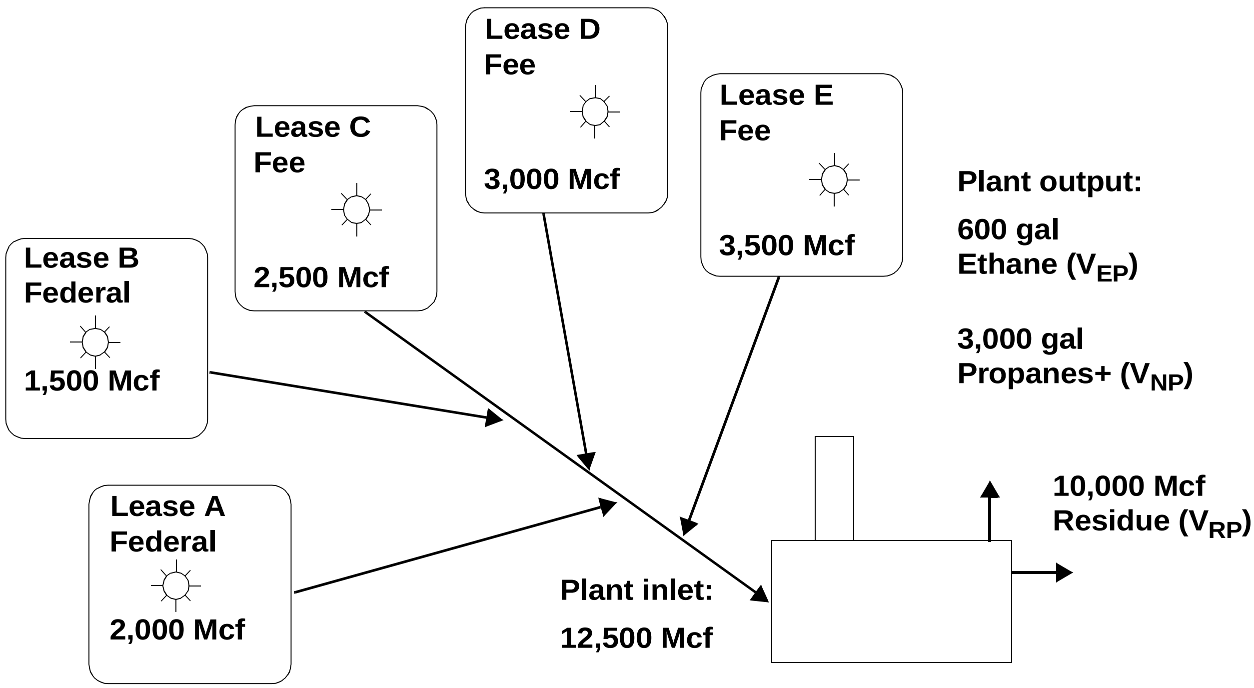
2.4.4.3 Alternative methods for determining quantity and quality

If the quantities of residue gas and gas plant products allocable to each lease cannot be determined by the prescribed methods, the lessee may request approval to use an alternative allocation method (30 CFR 206.154(c)(4) and 30 CFR 206.174(c)(4)). If MMS approves the lessee's method, this method is applied to gas production from all Federal and Indian leases supplying gas to that plant.

The lessee's proposed allocation method must be a reasonable method based on the specific variables applicable to the gas processed in that plant. For instance, if gas of nonuniform content is processed through a plant and ethane in a vapor phase must be added to the residue gas to meet pipeline requirements, the lessee may propose an allocation method that allocates liquid ethane to lease production only if the tested ethane content of the lease production is greater than the ethane content required by the pipeline for the residue gas.

Figure 2-5 illustrates an alternative allocation method for determining quantity and quality that is based on ethane content.

Gas production from five leases is processed at the Fossil Fuel Processing Plant. Leases A and B produce gas that is relatively ethane lean; that is, the tested ethane content of the lease production is less than the ethane required to meet pipeline quality. The remaining leases produce gas that is ethane rich. The residue gas from the Fossil Fuel Processing Plant must meet a sales contract requirement of 1,000 Btu/ft^3. In order to meet this requirement, ethane entrained in the gas after processing must be at least 0.20 GPM.



Test residue gas, ethane, and other NGLs (propanes+) contents measured for each lease are:

	Residue gas content (mole %)	NGLs: Ethane content (GPM)	NGLs: Propanes+ content (GPM)
Lease A:	95	0.10	0.15
Lease B:	90	0.15	0.20
Lease C:	85	0.25	0.20
Lease D:	80	0.30	0.30
Lease E:	75	0.30	0.40

FIGURE 2-5. Alternate allocation method based on ethane content (1 of 4)

The theoretical volumes of residue gas available from each lease (V_{RL}) are:

Lease A:	V_{R1}	=	**2,000 Mcf**	×	**0.95**	=	**1,900 Mcf**
Lease B:	V_{R2}	=	**1,500 Mcf**	×	**0.90**	=	**1,350 Mcf**
Lease C:	V_{R3}	=	**2,500 Mcf**	×	**0.85**	=	**2,125 Mcf**
Lease D:	V_{R4}	=	**3,000 Mcf**	×	**0.80**	=	**2,400 Mcf**
Lease E:	V_{R5}	=	**3,500 Mcf**	×	**0.75**	=	**2,625 Mcf**

The theoretical volume of residue gas available from all leases (V_{RA}) is:

$$1,900\ \text{Mcf} + 1,350\ \text{Mcf} + 2,125\ \text{Mcf} + 2,400\ \text{Mcf} + 2,625\ \text{Mcf}$$
$$= 10,400\ \text{Mcf}$$

The ethane recovery from each lease based on the required ethane content of residue gas at the tailgate of the plant is:

	Lease gas ethane (GPM)		Residue gas ethane (GPM)		Recoverable ethane (GPM)
Lease A:	**0.10**	–	**0.20**	=	**0***
Lease B:	**0.15**	–	**0.20**	=	**0***
Lease C:	**0.25**	–	**0.20**	=	**0.05**
Lease D:	**0.30**	–	**0.20**	=	**0.10**
Lease E:	**0.30**	–	**0.20**	=	**0.10**

*** Because the tested ethane contents of leases A and B are less than the residue gas ethane content required under the sales contract, no ethane is allocated to these leases.**

The theoretical volumes of ethane recoverable from each lease (V_{EL}) are:

Lease A:	V_{E1}	=	**2,000 Mcf**	×	**0 GPM**	=	**0 gal**
Lease B:	V_{E2}	=	**1,500 Mcf**	×	**0 GPM**	=	**0 gal**
Lease C:	V_{E3}	=	**2,500 Mcf**	×	**0.05 GPM**	=	**125 gal**
Lease D:	V_{E4}	=	**3,000 Mcf**	×	**0.10 GPM**	=	**300 gal**
Lease E:	V_{E5}	=	**3,500 Mcf**	×	**0.10 GPM**	=	**350 gal**

FIGURE 2-5. Alternate allocation method based on ethane content (2 of 4)

The theoretical volume of ethane recoverable from all leases (V_{EA}) is:

$$125 \text{ gal} + 300 \text{ gal} + 350 \text{ gal} = 775 \text{ gal}$$

The theoretical volumes of propanes+ available from each lease (V_{NL}) are:

Lease A:	V_{P1}	=	**2,000 Mcf**	×	**0.15 GPM**	=	**300 gal**
Lease B:	V_{P2}	=	**1,500 Mcf**	×	**0.20 GPM**	=	**300 gal**
Lease C:	V_{P3}	=	**2,500 Mcf**	×	**0.20 GPM**	=	**500 gal**
Lease D:	V_{P4}	=	**3,000 Mcf**	×	**0.30 GPM**	=	**900 gal**
Lease E:	V_{P5}	=	**3,500 Mcf**	×	**0.40 GPM**	=	**1,400 gal**

The theoretical volume of propanes+ available from all leases (V_{NA}) is:

$$300 \text{ gal} + 300 \text{ gal} + 500 \text{ gal} + 900 \text{ gal} + 1,400 \text{ gal} = 3,400 \text{ gal}$$

The theoretical volumes of residue gas, ethane, and propanes+ allocated to each lease based on the net plant output are:

Residue gas (V_{RT})

Lease A: $$10{,}000 \text{ Mcf} \times \frac{1,900 \text{ Mcf}}{10,400 \text{ Mcf}} = 1{,}827 \text{ Mcf}$$

Lease B: $$10{,}000 \text{ Mcf} \times \frac{1,350 \text{ Mcf}}{10,400 \text{ Mcf}} = 1{,}298 \text{ Mcf}$$

Lease C: $$10{,}000 \text{ Mcf} \times \frac{2,125 \text{ Mcf}}{10,400 \text{ Mcf}} = 2{,}043 \text{ Mcf}$$

Lease D: $$10{,}000 \text{ Mcf} \times \frac{2,400 \text{ Mcf}}{10,400 \text{ Mcf}} = 2{,}308 \text{ Mcf}$$

Lease E: $$10{,}000 \text{ Mcf} \times \frac{2,625 \text{ Mcf}}{10,400 \text{ Mcf}} = 2{,}524 \text{ Mcf}$$

FIGURE 2-5. Alternate allocation method based on ethane content (3 of 4)

Ethane (V_{ET})

Lease A:	**600 gal**	**x**	$\frac{0 \text{ gal}}{775 \text{ gal}}$	**=**	**0 gal**
Lease B:	**600 gal**	**x**	$\frac{0 \text{ gal}}{775 \text{ gal}}$	**=**	**0 gal**
Lease C:	**600 gal**	**x**	$\frac{125 \text{ gal}}{775 \text{ gal}}$	**=**	**97 gal**
Lease D:	**600 gal**	**x**	$\frac{300 \text{ gal}}{775 \text{ gal}}$	**=**	**232 gal**
Lease E:	**600 gal**	**x**	$\frac{350 \text{ gal}}{775 \text{ gal}}$	**=**	**271 gal**

Propanes^{+} (V_{NT})

Lease A:	**3,000 gal**	**x**	$\frac{300 \text{ gal}}{3{,}400 \text{ gal}}$	**=**	**265 gal**
Lease B:	**3,000 gal**	**x**	$\frac{300 \text{ gal}}{3{,}400 \text{ gal}}$	**=**	**265 gal**
Lease C:	**3,000 gal**	**x**	$\frac{500 \text{ gal}}{3{,}400 \text{ gal}}$	**=**	**441 gal**
Lease D:	**3,000 gal**	**x**	$\frac{900 \text{ gal}}{3{,}400 \text{ gal}}$	**=**	**794 gal**
Lease E:	**3,000 gal**	**x**	$\frac{1{,}400 \text{ gal}}{3{,}400 \text{ gal}}$	**=**	**1,235 gal**

FIGURE 2-5. Alternate allocation method based on ethane content (4 of 4)

2.5 General Valuation Principles

Lessees of Federal and Indian lands have an obligation to prudently market production to the mutual benefit of the lessee and the lessor. As a general rule, the **minimum value** of production for royalty purposes is the **gross proceeds** received under an **arm's-length contract** for the sale of production in marketable condition, less applicable allowances.

2.5.1 Arm's-length contracts

The cornerstone of valuation for royalty purposes is the arm's-length contract (see definition at 30 CFR §§ 206.51, 206.101, 206.151, and 206.171). Arm's-length contracts are contracts or agreements that were arrived at in the marketplace between independent, nonaffiliated persons with opposing economic interests regarding those contracts. Prices to which a lessee is legally entitled under an arm's-length contract are usually determined by market forces and thus represent the best measure of market value. For this reason, prices established in arm's-length contracts form the basis on which prices in non-arm's-length contracts are judged. If a non-arm's-length contract is equivalent to other arm's-length contracts in the field or area in terms of price, time of execution, duration, market(s) served, terms, quality of production, volume, and other factors, that non-arm's-length contract may be used for valuation purposes.

2.5.2 Gross proceeds

Under no circumstances can value be less than the **gross proceeds** received by a lessee under its contract, whether that contract is arm's-length or non-arm's-length (30 CFR §§ 206.52(h), 206.102(h), 206.152(h), 206.153(h), 206.172(h), and 206.173(h)). The gross proceeds on which a valuation determination is made include all consideration passing between the buyer and seller for production from Federal or Indian leases, whether that consideration is in the form of money or any other form of value. Gross proceeds include reimbursements paid to the lessee for severance and ad valorem taxes and any payments to the lessee for certain services, such as placing the lease production in **marketable condition**, to the extent that the lessee is obligated to perform such services at no cost to the Federal or Indian lessor. (See "Marketable condition" on p. 2-23 for more information.)

Reimbursements received by lessees from purchasers for certain production-related costs under Section 110 of the Natural Gas Policy Act (NGPA), 15 U.S.C. 3320, and FERC Order No. 94 and related orders (FERC 94 payments) are part of the lessee's gross proceeds (*Mesa Operating Limited Partnership* v. *U.S. Department of the Interior*, 931 F.2d 318 (5th Cir. 1991); cert. denied, 112 S. Ct. 934 (1992)).

Gross proceeds also include all prices or benefits to which a lessee is legally entitled under the terms of the contract, even if the lessee fails to take proper or timely action to secure such benefits.

2.5.3 Contract compliance

The value of production for royalty purposes must be based on the highest price the lessee can receive through legally enforceable claims under its contract (30 CFR §§ 206.52(j), 206.102(j), 206.152(j), 206.153(j), 206.172(j), and 206.173(j)). If the lessee fails to take proper or timely action to receive prices or benefits that are authorized by the contract, the lessee must pay royalty at a value based on the obtainable price or benefit, unless the contract has been revised or amended. Revisions or amendments to contracts must be in writing and signed by all parties to that contract.

Contract disputes. If a purchaser unilaterally reduces contract prices and the lessee takes documented, timely action to force compliance, the lessee should compute royalties on the actual price received until the dispute is resolved. An example of unilateral price reduction would be when a purchaser imposes a market-out price under a contract that does not contain any market-sensitive price provisions.

Likewise, if the lessee makes documented, timely application for a price increase or benefit entitled by the contract but the purchaser refuses, and the lessee takes reasonable measures to force compliance, the lessee does not owe additional royalties unless or until monies or consideration resulting from a price increase or benefit are received (30 CFR §§ 206.52(j), 206.102(j), 206.152(j), 206.153(j), 206.172(j), and 206.173(j)). That is, the lessee continues to pay royalties based on the gross proceeds received for arm's-length sales or the value under the "benchmark system" established at 30 CFR §§ 206.52(c), 206.102(c), 206.152(c), 206.153(c), 206.172(c), and 206.173(c) for non-arm's-length sales until the dispute is settled.

When a dispute is settled, royalty is owed on any additional amount the lessee receives and is due by the end of the month following the month the additional amount is collected.

All actions taken by the lessee to enforce compliance must be documented. Determinations under 30 CFR §§ 206.52(j), 206.102(j), 206.152(j), 206.153(j), 206.172(j), and 206.173(j) depend on the circumstances of each case. However, any action taken by the lessee to enforce compliance must be taken as soon as the lessee knows or should reasonably know that compliance measures should be taken.

Late purchaser payments. If a purchaser fails to pay whether in whole, in part, or timely for a quantity of production removed from the lease or unitized or communitized area, the lessee's obligation to pay royalties on the volume removed at the time of removal is not suspended. For example, if a purchaser removes production from a lease and payment is not received by the time the lessee must report and pay royalties, the lessee must still report the volume removed from the lease and pay royalties on that volume. In those cases where the lessee is not paid by the purchaser, royalties are determined based on the price established by the contract for arm's-length sales or on a value determined under the benchmark system for non-arm's-length sales.

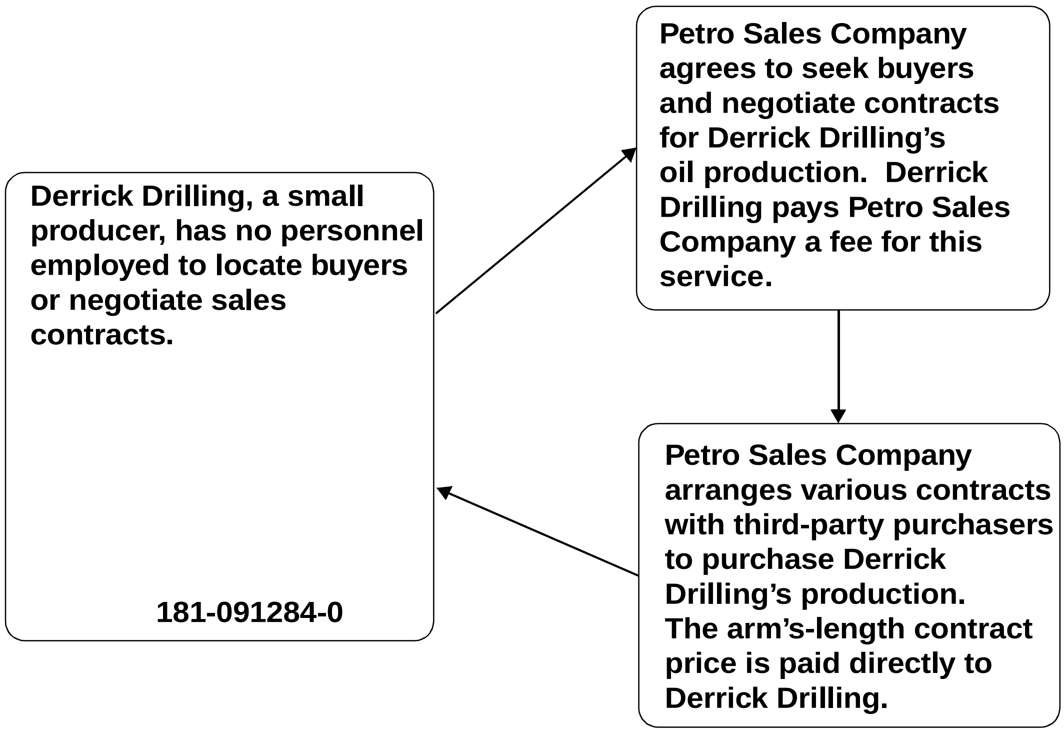
2.5.4 Marketable condition

Royalty is due on production that is in marketable condition; that is, production sufficiently free of impurities and in a condition that is accepted by a purchaser under a sales contract typical for the field or area. The lessee is responsible for placing lease production in marketable condition at no cost to the lessor unless otherwise provided in the lease agreement or regulations (30 CFR §§ 206.52(i), 206.102(i), 206.152(i), 206.153(i), 206.172(i), and 206.173(i)).

Placing production in marketable condition includes the physical handling and treatment of production such as gathering, measuring, separating, compressing, sweetening, and dehydrating. If the lease's gross proceeds are reduced by any costs associated with handling or treating production, the gross proceeds must be increased by the amount of such deductions.

The lessee is also obligated to market the production to the mutual benefit of the lessor and the lessee, whether the lessee uses its own employees to perform marketing services or pays another company to provide such services. If the purchaser incurs costs to market the production, the lessee cannot reduce the sales price to compensate the purchaser for those marketing costs. Neither can the lessee pay another entity for marketing services and deduct the costs of those services from the royalty value.

Figure 2-6 illustrates royalty valuation when a lessee enters into a contract with a third-party broker to market lease production.



Derrick Drilling is obligated to market the production for the mutual benefit of the lessor and the lessee.

The value for royalty purposes is the arm's-length price Derrick receives from the various third-party purchasers.

Derrick cannot deduct the marketing or brokerage fees charged by Petro Sales Company.

FIGURE 2-6. Consideration of marketing costs in determining royalty value

2.5.5 Like-quality production

When Federal or Indian production is not sold under an arm's-length contract (that is, production is disposed of under non-arm's-length or no-sales conditions), value of that production is based, in part, on the value of **like-quality production** sold under arm's-length contracts in the same field or area where the leased lands are situated. Like-quality production (or lease products) is defined (at 30 CFR 206.51 and 30 CFR 206.101 for oil and 30 CFR 206.151 and 30 CFR 206.171 for gas) as production or products having similar chemical, physical, and legal characteristics.

For valuation purposes, like-quality oil is oil that has similar American Petroleum Institute (API) gravity, sulfur content, paraffin (wax) content, heavy metals components, pour point, and other characteristics. Like-quality gas is gas that has similar methane, NGLs, and nonhydrocarbon gas content (sulfur dioxide, helium, nitrogen, CO_2, etc.) and is classified under the same NGPA wellhead pricing category.

Generally, like-quality production will be other production from the same field or area. However, only production that is similar in quality will be used to determine value. For instance, if a lessee's gas sold under a non-arm's-length contract qualifies as NGPA Section 102 gas, and other gas from different wells in the same field is classified as NGPA Section 107 gas, the prices paid for the NGPA Section 107 gas will not be used to determine the value of the lessee's gas for royalty purposes.

2.6 Unitization and Communitization Agreements

Unitization agreements, also known as units, are established to provide for the unified development and operation of an entire geologic structure or area so that drilling and production can proceed in the most efficient and economical manner.

Production from a unit is normally allocated to each tract of unitized land within the controlling participating area(s) (PA) on a surface-area basis, a volumetric basis, or a combination of these and/or other factors. For royalty purposes, all oil and gas produced from a Federally approved unit must be allocated to the participating Federal or Indian leases under the allocation requirements contained in the unit agreement. Lessees are responsible for paying royalties on the volume of production established in the agreement allocation schedule. Value of the allocated volumes is determined by lease terms and regulations.

Communitization agreements (CAs) are agreements established to allow the development of separate tracts that could not be fully and independently developed and operated because of limitations imposed by established well spacing programs. Communitization is required in order to conform with nonoptional spacing patterns established by State order.

Production under a CA is normally allocated to a Federal or Indian tract(s) within the CA based on the ratio of the surface acreage of the tract(s) to the total surface acreage within the CA. For royalty purposes, all oil and gas produced from a Federally approved CA must be allocated to the communitized Federal or Indian tract(s) under the allocation requirements contained in the CA. Lessees are responsible for paying royalties on the volume of production established in the agreement allocation schedule. Value of the allocated volumes is determined by lease terms and regulations.

2.6.1 Royalty on agreement production

If a lessee of a lease that is committed to a Federally approved unit or CA does not actually take the proportionate share of production allocated to the lease under the terms of the agreement, the full share of production attributable to the lease is nonetheless subject to royalty (30 CFR 202.100(e)(1) and 30 CFR 202.150(e)(1)). In other words,

royalty on production allocated to a Federal or Indian lease is due when the production is removed from the lease, unit, or CA, regardless of who takes that production. MMS does not allow the lessee to remove allocated production from the lease without payment of royalties. If royalties are not paid, the lease/agreement terms have been violated, and the lessee is held responsible for payment of royalties.

When a lessee is entitled to production but does not take its full allocated share, the circumstances involved in the actual disposition of production determine which valuation method the lessee must use. Valuation of the lessee's share of allocated production that is not taken by the lessee is treated in the same manner as if the person actually selling or otherwise disposing of that production was a Federal or Indian lessee. If allocated production not taken by the lessee is sold under an arm's-length contract, value is usually based on the gross proceeds accruing to the seller. If allocated production not taken by the lessee is sold under a non-arm's-length contract or is subject to other dispositions not involving an arm's-length contract, value is based on the benchmark system.

In summary, three factors affect the value of production allocated to a unit or CA:

1. **Volume**. Royalty must be paid on the volume of production allocated to the Federal or Indian lease. Volume is determined at the BLM- or MMS-approved point-of-royalty settlement as specified in the approved allocation schedule in effect for the production month.

2. **Value**. Actual disposition determines the value of production. The seller's contracts determine how production will be valued, whether that seller is the lessee or is another person taking the lessee's share of allocated production. If the sales contract is arm's-length, the gross proceeds generally determine value. If sales are under a non-arm's-length contract or by other dispositions not involving an arm's-length contract, the benchmark system is used to determine value.

3. **Royalty rate**. Royalty must be paid on the rate specified in the individual lease document.

2.6.2 Royalty payments on agreement production

When a lessee takes less than its full share of allocated production for any given month, but royalties are paid based on its full share, no additional royalty is due for prior periods when the lessee subsequently takes more than its share to balance its account or when the lessee is paid a sum of money by the other agreement participants to balance its account.

For instance: A lessee is entitled to take 1,000 barrels (bbl) of oil as its allocated share for a given month. The lessee actually takes 200 bbl for that month, but pays royalties on the full allocated share (1,000 bbl) of oil under the allocation and valuation methods in 30 CFR 202 and 30 CFR 206, respectively. When the lessee later balances its account at a price per unit that is higher (or lower) than the price per unit upon which royalties were paid, no adjustment to prior period royalties is necessary.

2.6.3 Alternative agreement valuation methods

If a lessee experiences difficulty in complying with the valuation method established for agreement production, the lessee may request to use alternative valuation methods under one of two provisions of the regulations.

The first provision, occurring at 30 CFR 202.100(e)(2) and 30 CFR 202.150(e)(2), allows any individual lessee taking **less than** its proportionate share of production to request approval from MMS to use a method different from that method described in "Royalty on agreement production" on page 2-27. This alternative method must be consistent with the purpose of the regulations. Use of an alternative valuation method under these particular regulations is not dependent on the use of this same method by all other lessees that are a party to the unit or CA.

The second provision, occurring at 30 CFR 202.100(f) and 30 CFR 202.150(f), allows the lessee to request approval from MMS to use an alternative method, provided that the method is consistent with statutes and lease and agreement terms.

Lessees are permitted to use this alternative method under these conditions:

- All interest owners (including royalty interest owners, where practical) are given notice and an opportunity to comment on the proposed valuation method before it is authorized; and
- All interest owners (including royalty interest owners, where practical) agree to use the proposed valuation method for valuing production from the unit or CA for royalty purposes.

2.6.4 Ratable takes

When a lessee with an interest in tracts in either a PA in a unit or a CA takes volumes that are greater than its allocated share of production in any month, MMS first considers the excess to have been taken ratably from **all** of its co-lessees in the same tract that took less than their allocated share of agreement production for that month (30 CFR 202.150(e)(3)). However, this consideration is made provided that the lessee's sale can be tied to that tract by the lessee's ownership interest and/or contractual arrangements. After each lessee's overage or underage has been ratably distributed within the tract, if a tract is still over- or underdelivered in total, the excess volumes from the overdelivered tracts in the unit or CA are ratably allocated to the underdelivered tracts.

Figure 2-7 illustrates how excess volumes from one or more tracts in a unit are ratably allocated to the underdelivered tracts.

The Red Rocks Unit produces 50,000 Mcf in a given month. Each tract in the unit is entitled to 25 percent of the total unit production.

The working interest and royalty interest ownership for each tract is shown as follows:

Tract 1		Tract 2	
Derrick Drilling	50%	Derrick Drilling	100%
Bit Exploration	25%		
Kelly Corporation	25%		
		MMS	6.25%
MMS	12.5%	Fee	6.25%
Tract 3		**Tract 4**	
Rotary Resources	75%	Swivel Production	50%
Swivel Production	25%	Kelly Corporation	50%
Fee	12.5%	MMS	16.67%

Contract sales arrangements for each owner are shown in the following table:

Tract	Owner	Sales (Mcf)	Price ($/Mcf)	Purchaser
1	Derrick Drilling	1,000	$2.00	Basin Transportation
1	Bit Exploration	7,000	$2.25	Desert Distributors
1	Kelly Corporation	5,000	$1.90	Valley Pipeline
2	Derrick Drilling	10,000	$2.00	Basin Transportation
3	Rotary Resources	15,000	$1.85	Mountain Refinery
3	Swivel Production	5,000	$1.75	Desert Distributors
4	Swivel Production	7,000	$1.75	Desert Distributors
4	Kelly Corporation	(has no contract)		

FIGURE 2-7. Allocation of unit production based on ratable takes (1 of 5)

The differences between allocated volumes and actual sales volumes and the amounts over- and underdelivered for each tract in the Red Rocks Unit are shown below:

Owner	Tract	Allocated volume (Mcf)	Sales volume (Mcf)	Price ($/Mcf)	Sales value	Volume over/(under) (Mcf)
Derrick Drilling	1	6,250	1,000	$2.00	$ 2,000	(5,250)
Bit Exploration	1	3,125	7,000	2.25	15,750	3,875
Kelly Corporation	1	3,125	5,000	1.90	9,500	1,875
		12,500	13,000		$27,250	500
Derrick Drilling	2	12,500	10,000	2.00	$20,000	(2,500)
Rotary Resources	3	9,375	15,000	1.85	$27,750	5,625
Swivel Production	3	3,125	5,000	1.75	8,750	1,875
		12,500	20,000		$36,500	7,500
Swivel Production	4	6,250	7,000	1.75	$12,250	750
Kelly Corporation	4	6,250	0		0	(6,250)
		12,500	7,000		$12,250	(5,500)
TOTAL		50,000	50,000		$96,000	0

Ratable takes for the overtaking parties are determined for the Red Rocks Unit as follows:

Total overage:

500 Mcf	Total Tract 1 overage
+ 7,500	Total Tract 3 overage
8,000 Mcf	Total overage to be ratably allocated back to each underdelivered tract

Tract 1 overage:

Bit's portion of the total Tract 1 overage:

$$\frac{3{,}875\ \text{Mcf}}{5{,}750\ \text{Mcf}} = 0.6739 \qquad 0.6739 \times 500\ \text{Mcf} = 337\ \text{Mcf}$$

Kelly's portion of the total tract 1 overage:

$$\frac{1{,}875\ \text{Mcf}}{5{,}750\ \text{Mcf}} = 0.3261 \qquad 0.3261 \times 500\ \text{Mcf} = 163\ \text{Mcf}$$

FIGURE 2-7. Allocation of unit production based on ratable takes (2 of 5)

Tract 3 overage:

Rotary's portion of total Tract 3 overage: 5,625 Mcf
Swivel's portion of total Tract 3 overage: 1,875 Mcf

Percentage of total unit volume overtaken by each party:

Bit: $\dfrac{337\ \text{Mcf}}{8{,}000\ \text{Mcf}} = 0.0421$

Kelly: $\dfrac{163\ \text{Mcf}}{8{,}000\ \text{Mcf}} = 0.0204$

Rotary: $\dfrac{5{,}625\ \text{Mcf}}{8{,}000\ \text{Mcf}} = 0.7031$

Swivel: $\dfrac{1{,}875\ \text{Mcf}}{8{,}000\ \text{Mcf}} = 0.2344$

Ratable takes for undertaken tracts in the Red Rocks Unit are determined as follows:

Ratable takes for Tract 2:

Total Tract 2 underage: 2,500 Mcf

0.0421		Bit's portion of total overage
× 2,500	Mcf	Tract 2 underage
105	Mcf	Portion of Tract 2 underage attributable to Bit's price
0.0204		Kelly's portion of total overage
× 2,500	Mcf	Tract 2 underage
51	Mcf	Portion of Tract 2 underage attributable to Kelly's price
0.7031		Rotary's portion of the total overage
× 2,500	Mcf	Tract 2 underage
1,758	Mcf	Portion of Tract 2 underage attributable to Rotary's price

FIGURE 2-7. Allocation of unit production based on ratable takes (3 of 5)

Ratable takes for Tract 2 (continued):

0.2344		**Swivel's portion of total overage**
× 2,500	**Mcf**	**Tract 2 underage**
586	**Mcf**	**Portion of Tract 2 underage attributable to Swivel's price**

Ratable takes for Tract 4:

Total Tract 4 underage: 5,500 Mcf

0.0421		**Bit's portion of total overage**
× 5,500	**Mcf**	**Tract 4 underage**
232	**Mcf**	**Portion of Tract 4 underage attributable to Bit's price**
0.0204		**Kelly's portion of total overage**
× 5,500	**Mcf**	**Tract 4 underage**
112	**Mcf**	**Portion of Tract 4 underage attributable to Kelly's price**
0.7031		**Rotary's portion of total overage**
× 5,500	**Mcf**	**Tract 4 underage**
3,867	**Mcf**	**Portion of Tract 4 underage attributable to Rotary's price**
0.2344		**Swivel's portion of total overage**
× 5,500	**Mcf**	**Tract 4 underage**
1,289	**Mcf**	**Portion of Tract 4 underage attributable to Swivel's price**

FIGURE 2-7. Allocation of unit production based on ratable takes (4 of 5)

Each lessee (or other entity reporting and paying for the lessee) would report and pay on the ratably distributed volumes as follows:

Lessee or other reporter	Tract	Price per Mcf	Volume (Mcf)	Value subject to royalty	MMS royalty rate (%)	MMS royalty
Derrick Drilling	1	$2.00	1,000	$ 2,000.00	12.50	$ 250.00
Bit Exploration	1	2.25	6,663	14,991.75	12.50	1,873.97
Kelly Corporation	1	1.90	4,837	9,190.30	12.50	1,148.79
			12,500	$26,182.05		$3,272.76
Derrick Drilling	2	2.00	10,000	$20,000.00	6.25	$1,250.00
Bit Exploration	2	2.25	105	236.25	6.25	14.77
Kelly Corporation	2	1.90	51	96.90	6.25	6.06
Rotary Resources	2	1.85	1,758	3,252.30	6.25	203.27
Swivel Production	2	1.75	586	1,025.50	6.25	64.09
			12,500	$24,610.95		$1,538.19
Rotary Resources	3	1.85	9,375	$17,343.75	0	$ 0.00
Swivel Production	3	1.75	3,125	5,468.75	0	0.00
			12,500	$22,812.50		$ 0.00
Swivel Production	4	1.75	7,000	$12,250.00	16.67	$2,042.08
Bit Exploration	4	2.25	232	522.00	16.67	87.02
Kelly Corporation	4	1.90	112	212.80	16.67	35.48
Rotary Resources	4	1.85	3,867	7,153.95	16.67	1,192.56
Swivel Production	4	1.75	1,289	2,255.75	16.67	376.03
			12,500	$22,394.50		$3,733.17
Total			50,000	$96,000.00		$8,544.12

FIGURE 2-7. Allocation of unit production based on ratable takes (5 of 5)

2.7 Deduction of Transportation and Processing Allowances

Reasonable, actual transportation and/or processing allowances are recognized deductions from the **value** of production (30 CFR §§ 206.54, 206.104, 206.156, 206.158, 206.176, and 206.178). Allowances are not deductions from royalties. The lessee must first establish the value of production, then deduct the allowances from that value. This net value is the value on which royalties are paid.

Transportation and processing allowances must be reported separately to AFS using transaction codes (TCs) 11 and 15, respectively, on the Report of Sales and Royalty Remittance (Form MMS-2014). (See the *Oil and Gas Payor Handbook, Volume II*, for specific reporting instructions.) Preapproval of most allowances after March 1, 1988, is not required by MMS. However, the proper allowance forms (Oil Transportation Allowance Report (Form MMS-4110), Gas Transportation Allowance Report (Form MMS-4295), and/or Gas Processing Allowance Summary Report (Form MMS-4109)) for Indian leases **must** be submitted to MMS before deductions can be claimed. Lessees must follow the procedures explained in Chapter 5, "Oil Transportation Allowances," Chapter 6, "Gas Transportation Allowances," and Chapter 7, "Gas Processing Allowances," of this handbook for calculating allowances.

3. Oil Valuation

This chapter describes the methods and procedures for valuing oil produced from Indian lands and for valuing oil produced from Federal lands before June 1, 2000. In addition to the general requirements discussed in Chapter 2, "Valuation Overview," the lessee must follow the procedures outlined in this chapter for oil valuation. Except where the major portion method must be used to value Indian oil, the valuation standards are the same for Federal onshore, OCS, and Indian production.

The value of oil is based primarily on whether or not the oil is sold under an arm's-length contract. For sales or dispositions under an **arm's-length** contract, the price specified in the contract is usually acceptable for determining value. For sales or dispositions not under an arm's-length contract, the value is determined under a benchmark system. All reported values are subject to monitoring, review, and audit.

NOTE

MMS published new Federal oil valuation regulations in the *Federal Register* on March 15, 2000 (65 FR 14022). The revised regulations, which became effective on June 1, 2000, add alternative valuation methods to the March 1, 1988, regulations to assure that royalties on Federal oil production are based on a fair value and to otherwise simplify and improve the rule.

For valuation of Federal oil production occurring on or after June 1, 2000, lessees must use the criteria contained in this new regulation.

A copy of this new regulation, "Establishing Oil Value for Royalty Due on Federal Leases: Final Rule" (65 FR 14022—March 15, 2000), can be found on MMS's web site at www.mrm.mms.gov under RMP FR Final Rules.

MMS will prepare an update to this payor handbook with specific instructions on how to determine value under the new Federal oil valuation regulations.

3.1 Valuation of Oil Sold Under an Arm's-Length Contract

In most cases, the value of oil sold under an arm's-length contract is the gross proceeds accruing to the lessee. Gross proceeds are also used to determine value in those cases where the oil is sold by the lessee's marketing affiliate under an arm's-length transaction (30 CFR 206.52(b)(1)(i) and 30 CFR 206.102(b)(1)(i)). However, MMS will not accept arm's-length gross proceeds (or contract prices) as royalty value if:

- The lessee's sales contract does not reflect the total consideration actually transferred, either directly or indirectly, from the buyer to the seller. If the contract does not reflect total consideration, MMS may require the lessee to determine value for royalty purposes under the benchmark system, which governs valuation for other than arm's-length transactions (30 CFR 206.52(b)(1)(ii) and 30 CFR 206.102(b)(1)(ii)). Value for royalty purposes can never be less than the gross proceeds accruing to the lessee, and those gross proceeds must include any additional consideration identified in the contract.

- The lessee's gross proceeds do not reflect the reasonable value of the oil because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the oil for the mutual benefit of the lessee and the lessor. MMS requires the oil to be valued according to the benchmark system (30 CFR 206.52(b)(1)(iii) and 30 CFR 206.102(b)(1)(iii)). When MMS determines that the value is unreasonable, the lessee is provided an opportunity to justify its valuation method.

If necessary, the lessee may be required to certify that its arm's-length contract discloses all of the consideration paid by the buyer, either directly or indirectly, for the oil (30 CFR 206.52(b)(2) and 30 CFR 206.102(b)(2)).

3.1.1 Total consideration

If the arm's-length contract does not set forth the total consideration passing directly or indirectly from the buyer to the lessee for the sale of oil, the lessee's gross proceeds may have to be adjusted to reflect the additional consideration (30 CFR 206.52(b)(1)(ii) and 30 CFR 206.102(b)(1)(ii)). In some cases, the contract may not reveal special arrangements between the buyer and the lessee that may affect sales prices. For instance, in return for the lessee's reduced price for oil, the buyer may agree to reduce the cost of services it sells to the lessee, or, under a separate arrangement, the purchaser may reimburse the lessee for services that the lessee is obligated to perform at no cost to the lessor. In these situations, the value of the other considerations must be included as part of the gross proceeds accruing to the lessee.

For example, in the situation described above, the lessee that sold oil at a reduced price under its sales contract and received reimbursement under a separate contract must increase its gross proceeds by the amount of the reimbursement to determine the value of the oil for royalty purposes (reimbursements become part of the consideration paid for the oil).

If the lessee is aware of considerations outside the "four corners" of the contract, the lessee should notify the MMS Royalty Valuation Division of such considerations and the circumstances under which they occur, and propose a valuation and/or request valuation guidance. Notification consists of a letter addressed to the Chief, Royalty Valuation Division. See "Important Addresses and Phone Numbers" on page 1-5.

3.1.2 Reasonable value

The lessee is obligated to negotiate contracts prudently and receive the best possible price to the mutual benefit of itself and the lessor. Even though a contract may be arm's-length, if MMS determines that the gross proceeds under that contract do not reflect a reasonable value because of misconduct between the contracting parties or because the lessee has otherwise breached its duty to market production for the mutual benefit of the lessee and the lessor, MMS requires that the oil be valued under the benchmark system (30 CFR 206.52(b)(1)(iii) and 30 CFR 206.102(b)(1)(iii)). Lessee misconduct or breach of duty may include, but is not limited to, such actions as collusion between the lessee/seller and purchaser, negligence in negotiating contracts, or pricing practices found by a court or regulatory authority to be incorrect or fraudulently manipulated.

If MMS determines the value to be unreasonable, MMS notifies the lessee and gives the lessee an opportunity to provide written justification for its value.

3.1.3 Sales by a marketing affiliate

Under certain circumstances, a lessee may choose to transfer oil produced from a Federal lease to its marketing affiliate. For royalty purposes, a marketing affiliate is an affiliate whose function is to acquire only the lessee's production and to market that production.

In instances where a lessee's affiliate meets the MMS definition of a marketing affiliate, oil that is transferred to this marketing affiliate and is subsequently sold by the marketing affiliate under an arm's-length contract is valued based on the gross proceeds accruing to the marketing affiliate (30 CFR 206.52(b)(1)(i) and 30 CFR 206.102(b)(1)(i)). If the lessee sells or transfers oil to its marketing affiliate and the marketing affiliate does not subsequently sell the oil under an arm's-length contract, the oil is valued under the benchmark system.

If the lessee transfers oil to an affiliate that also purchases oil from other sources, the affiliate does not qualify as a marketing affiliate for valuation purposes. In this case, the oil is valued under the benchmark system. When oil is transferred to an affiliate without a sales transaction, the value of the oil cannot be less than the gross proceeds received by the affiliate for sale of the oil (30 CFR 206.52(h) and 30 CFR 206.102(h)).

3.1.4 Transportation factors

If an arm's-length contract price or posted price includes a provision by which the listed price is reduced by a purchaser to reflect the purchaser's transportation costs and the lessee is paid a net value, the amount of the transportation reduction is deemed a transportation factor.

Generally, transportation factors occur when a purchaser establishes a price for oil at a location away from the point of title transfer and reduces that established price by the costs to move oil to the remote location. For instance, a purchaser posts prices under an oil price bulletin at an oil refinery and, under an arm's-length contract, agrees to pick up a lessee's oil at the lease. The contract specifies that the purchaser will pay the lessee the posted price at the refinery less the costs incurred by the purchaser to transport the oil from the lease to the refinery. The lessee receives a price that is net of transportation costs, and the reduction in price for transportation from the lease to the refinery is the transportation factor.

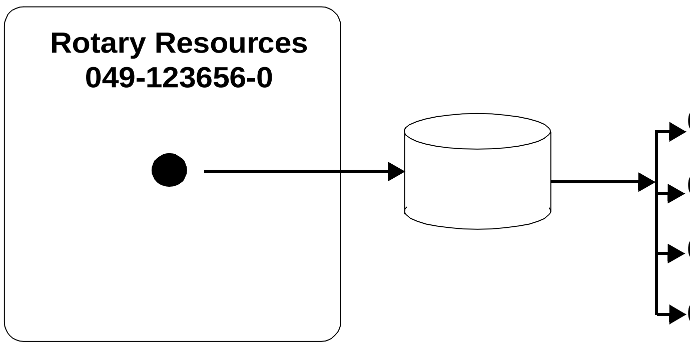
Because the lessee incurs no out-of-pocket costs for transportation, the transportation factor is not considered a transportation allowance (30 CFR 206.55(a)(5) and 30 CFR 206.105(a)(5)). For valuation purposes, the gross proceeds received by the lessee for oil sold under its arm's-length contract (net of the amount of the transportation factor) establish value for that oil. For reporting purposes, the lessee enters only one line on Form MMS-2014, representing the gross proceeds net of the transaction factor.

Transportation factors may not exceed 50 percent of the value of the oil at the sales point without MMS approval. If the lessee's transportation factor exceeds the 50-percent limit, the lessee must notify the Royalty Valuation Division in writing and request and receive approval to exceed the 50-percent limit prior to paying royalties based on its gross proceeds. See "Important Addresses and Phone Numbers" on page 1-5.

For additional information on oil transportation factors, see "Transportation factors" on page 5-4.

3.1.5 Arm's-length valuation examples

Figures 3-1 through 3-4 show examples of oil valuation based on the lessee's gross proceeds under arm's-length contracts.



Run date	°API Gravity	Vol. (bbl)
09/01	30	1,500
09/11	29	500
09/17	33	3,000
09/27	31	1,000

Rotary Resources sells to Valley Pipeline using Valley's posted price bulletin.

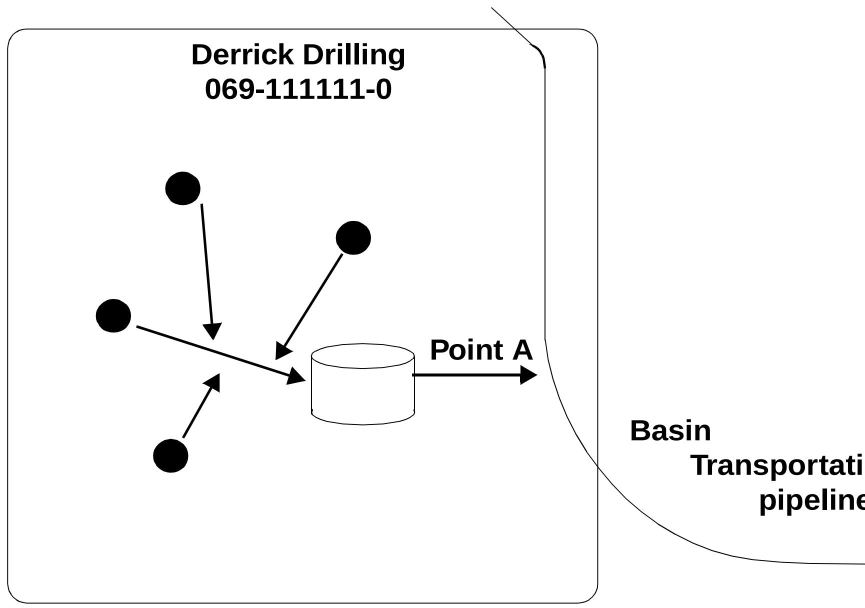
Gravity adjustment is $0.02 per 1.0 °API below 40°.

Run date	Posted price on run date	Gravity adjustment	Adjusted value
09/01	$25.50	$0.20	$25.30
09/11	28.50	0.22	28.28
09/17	30.00	0.14	29.86
09/27	33.25	0.18	33.07

Gross proceeds are calculated as follows:

$25.30	×	1,500 bbl	=	$37,950.00
28.28	×	500 bbl	=	14,140.00
29.86	×	3,000 bbl	=	89,580.00
33.07	×	1,000 bbl	=	33,070.00
				$174,740.00

FIGURE 3-1. Oil value based on gross proceeds accruing to the lessee under an arm's-length posted price contract



The contract between Derrick Drilling and Basin Transportation is arm's-length.

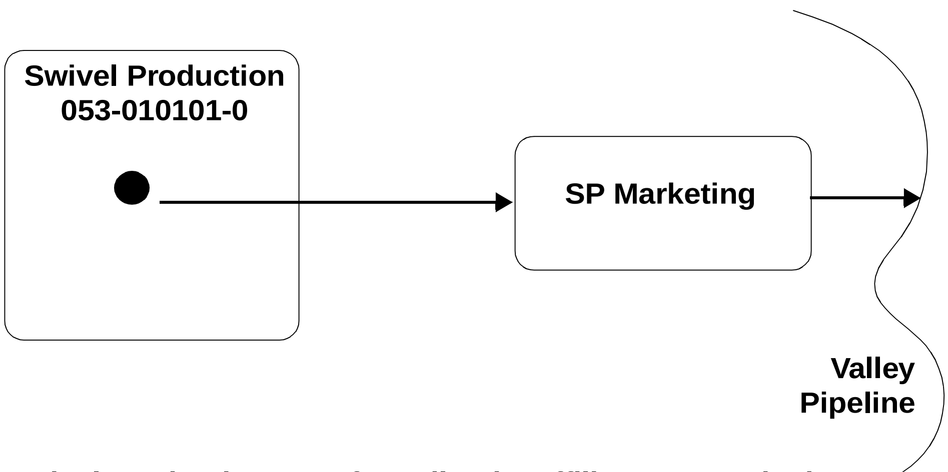
The sales point is Basin's pipeline tap at point A.

The contract price is based on a third-party posted price bulletin.

Derrick also has an informal agreement with Basin to construct an on-lease gathering system from the wellheads to the pipeline tap. Derrick receives $0.05/bbl from Basin as reimbursement for constructing the gathering system.

Gathering to move production to the point of sale is a service that the lessee is obligated to perform at no cost to the lessor. Therefore, the value for royalty purposes is based on the lessee's gross proceeds received under its contract plus the $0.05/bbl gathering reimbursement.

FIGURE 3-2. Oil value based on arm's-length gross proceeds that have been increased to include gathering costs reimbursed by the purchaser



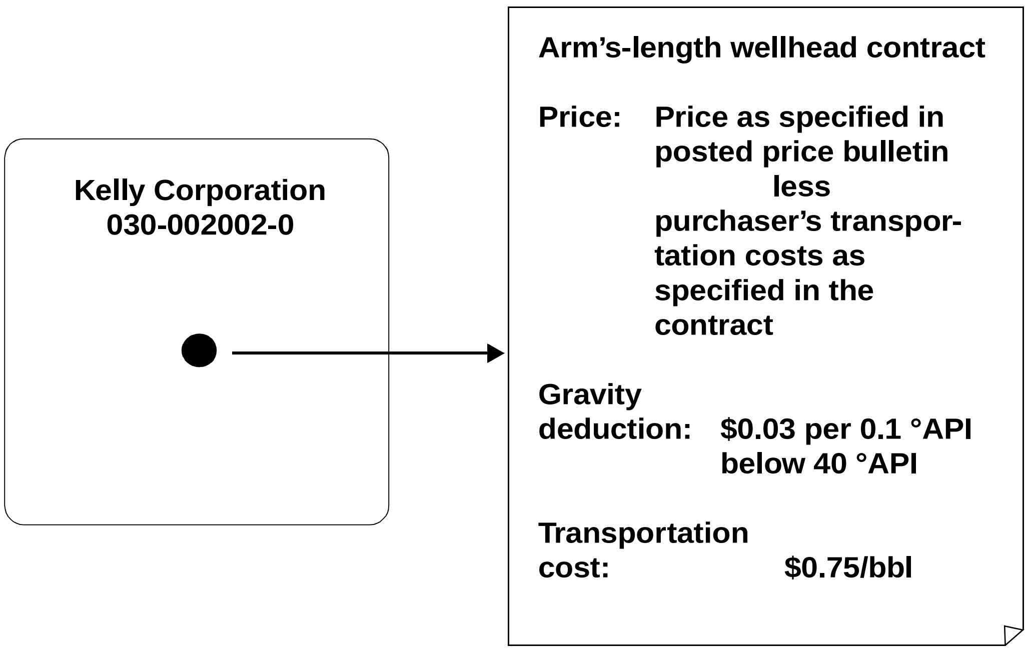
Swivel Production transfers oil to its affiliate, SP Marketing.

SP meets the definition of a marketing affiliate.

SP sells the oil in the spot market to Valley under an arm's length oil sales contract.

Swivel must value its production for royalty purposes based on the spot price received by its marketing affiliate, SP.

FIGURE 3-3. Oil value based on gross proceeds received by a lessee's marketing affiliate



Run date	Volume (bbl)	Gravity (°API)	Bulletin price	Gravity adjustment	Adjusted price
01/03	1,000	38.6	$27.25	$0.42	$26.83
01/18	500	39.1	20.25	0.27	19.98

Adjusted price		Transportation factor		Royalty value/bbl		Volume (bbl)		Gross proceeds
$26.83	–	$0.75	=	$26.08	×	1,000	=	$26,080.00
19.98	–	0.75	=	19.23	×	500	=	9,615.00

Total gross proceeds accruing to Kelly Corporation: $35,695.00

Value for royalty purposes is based on the gross proceeds accruing to Kelly under its arm's-length contract.

FIGURE 3-4. Consideration of an arm's-length transportation factor in determining oil value for royalty purposes

3.2 Valuation of Oil Not Sold Under an Arm's-Length Contract

For oil not sold under an arm's-length contract, including oil disposed of without a contract (that is, not sold) or any other arrangement for the sale or disposition of oil that does not meet the criteria of an arm's-length contract, value must be determined under the benchmark system established at 30 CFR 206.52(c) and 30 CFR 206.102(c). (Dispositions other than arm's-length are subsequently referred to as **non-arm's-length**.) However, value cannot be less than the gross proceeds accruing to the lessee under a non-arm's-length contract (30 CFR 206.52(h) and 30 CFR 206.102(h)).

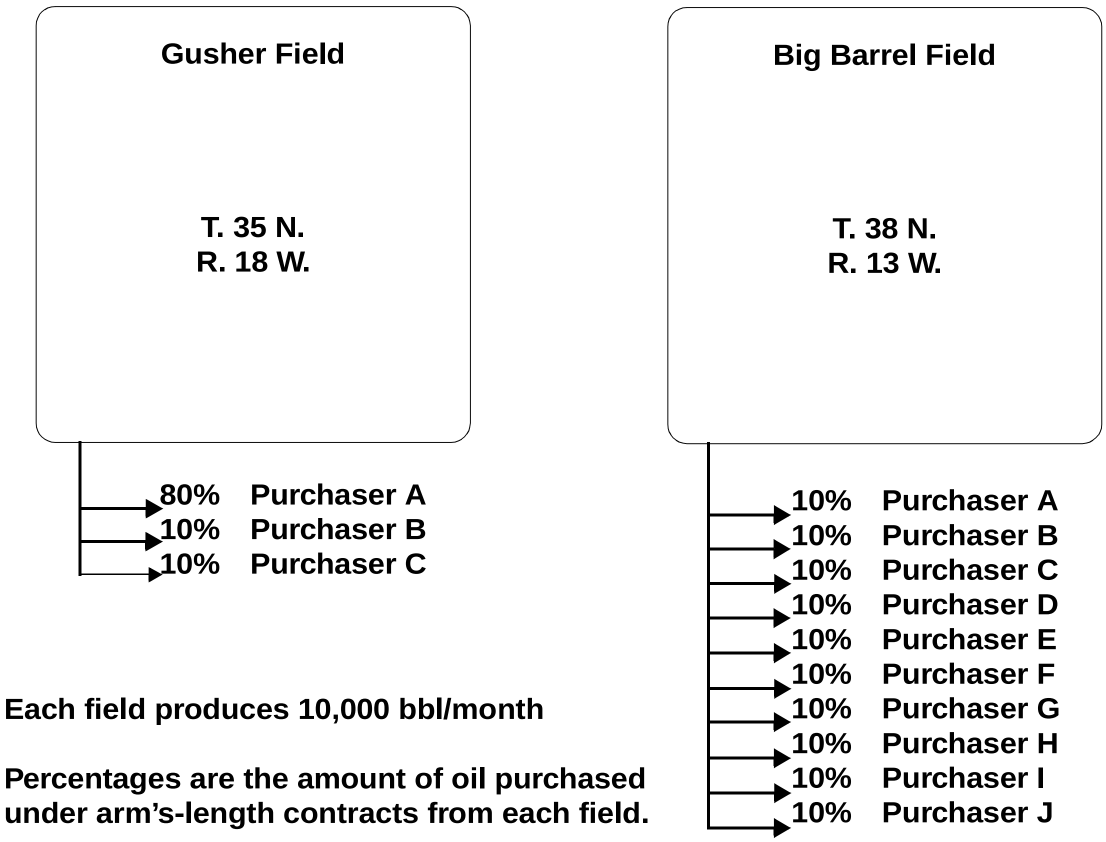
The benchmark system provides a series of prioritized standards or methods in which value is determined by the first applicable method. If the first benchmark does not apply or cannot be used, the lessee uses the second benchmark to determine value, and so on. The benchmark that first applies in any given situation is the one used to determine value. Five benchmarks are listed for non-arm's-length oil valuation.

The benchmark valuation standards are based on the principle that market value is determined through supply/demand interaction under arm's-length contracts, and arm's-length prices established under those contracts are the best measure of value. By using arm's-length contract prices, the lessee is assured some certainty in determining value for its own non-arm's-length transactions without MMS assistance or approval. The lessee may, however, request guidance from MMS if the lessee is uncertain of the proper valuation method to use.

Posted prices and arm's-length sales contract prices form the basis for valuation under the oil benchmark system. Arm's-length contracts for oil sales normally refer to posted prices as the pricing basis. These prices generally reflect the value of oil in the open market and can be used to determine royalty value. However, to be considered indicative of value for royalty purposes, the posted prices or arm's-length contract prices used in the value determination must be comparable to other **contemporaneous** posted or contract prices used in arm's-length transactions. Contemporaneous posted or sales contract prices are postings or prices in effect at the time oil is removed, sold, or otherwise disposed of (that is, prices in effect at the time the lessee incurs a royalty obligation).

In addition to the contemporaneity requirement, posted prices or arm's-length contract prices must also be associated with purchases or sales of **significant quantities** of like-quality production in the same field or area where the non-arm's-length transaction(s) occurs. "Significant quantities" has no precise definition and varies depending on the circumstances particular for each situation. A volume that represents a certain percentage of the total volume produced from a field may be considered a significant quantity of oil under one set of circumstances, but may not represent a significant quantity of oil in other circumstances. Figure 3-5 illustrates significant quantities.

The lessee must retain all relevant data for all value determinations under the benchmark system (30 CFR 206.52(e)(1) and 30 CFR 206.102(e)(1)).



Although Purchasers B and C both purchase the same percentage of the volume committed to arm's-length sales from each field, Purchasers B and C would not be considered purchasers of significant quantities of like-quality oil in the Gusher Field, but would be considered purchasers of significant quantities of like-quality oil in the Big Barrel Field.

FIGURE 3-5. Determination of purchasers of significant quantities of like-quality oil in a field or area

3.2.1 First valuation benchmark: Lessee's contemporaneous posted prices or oil sales contract prices used in arm's-length transactions

The first benchmark for non-arm's-length oil valuation applies in situations where the lessee has contemporaneous posted or contract prices used in arm's-length purchases or sales of significant quantities of like-quality oil in the same field or area. However, the lessee's posted or contract prices used in arm's-length purchases or sales must also be comparable to other contemporaneous posted or contract prices used in arm's-length purchases or sales of significant quantities of like-quality oil in the same field or area. In evaluating the comparability of posted or contract prices, MMS considers such factors as price, duration of the contract, market or markets served, terms, quality, volume, and other appropriate factors.

If the lessee's posted or contract prices used in arm's-length purchases or sales of significant quantities of like-quality oil are both contemporaneous and comparable, the established prices are used to determine value for the lessee's non-arm's-length transaction.

NOTE

However, if the lessee makes arm's-length purchases or sales at different posted or contract prices during the production month, value is determined by the volume-weighted-average price for the purchases or sales during that month.

Posted prices are generally established by the purchaser, marketer, or transporter, not the seller (usually the lessee or operator). However, some lessees may have affiliates that purchase oil under the affiliate's posting. For the purposes of royalty valuation, a lessee is defined as including the lessee's designated purchasing agent (30 CFR 206.52(c)(6) and 30 CFR 206.102(c)(6)). Thus, a lessee is considered to be a purchaser of significant quantities of like-quality oil in the same field or area if the lessee's affiliate purchases oil under those criteria.

3.2.2 Second valuation benchmark: Arithmetic average of contemporaneous posted prices used in arm's-length transactions by persons other than the lessee

The second benchmark for determining oil value is based on an arithmetic average of contemporaneous posted prices used in arm's-length transactions by persons **other than** the lessee for purchases or sales of significant quantities of like-quality oil in the same field or area (30 CFR 206.52(c)(2) and 30 CFR 206.102(c)(2)).

This benchmark requires consideration of postings by entities other than the lessee and would be used to determine value when a lessee does not purchase or sell a significant quantity of like-quality oil under arm's-length conditions, or if the lessee's posted prices are not comparable to other posted prices used in arm's-length transactions in the field or area.

Because postings do not always indicate a purchaser's willingness to buy, the arithmetic average should include only posted prices that were used in arm's-length transactions to purchase significant quantities of like-quality oil sold in the field or area.

3.2.3 Third valuation benchmark: Arithmetic average of other contemporaneous arm's-length contract prices in the area

The third benchmark for determining oil value is based on an arithmetic average of other contemporaneous arm's-length contract prices for purchases or sales of significant quantities of like-quality oil in the same area or nearby areas (30 CFR 206.52(c)(3) and 30 CFR 206.102(c)(3)).

This benchmark focuses on other arm's-length **contract** prices in the area or nearby areas for determining value for royalty purposes when there are **no posted prices** used in arm's-length purchases in the immediate field or area. Value is determined by computing an arithmetic average of the arm's-length prices. However, only purchases of significant quantities of like-quality oil under these arm's-length contracts are included in the calculation.

3.2.4 Fourth valuation benchmark: Arm's-length spot sales prices and other relevant matters

The fourth benchmark for determining oil value is based on prices received for arm's-length spot sales of significant quantities of like-quality oil from the same field or area and other relevant matters, including information submitted by the lessee concerning circumstances unique to a particular lease operation or the salability of certain types of oil (30 CFR 206.52(c)(4) and 30 CFR 206.102(c)(4)).

Generally, a lessee uses this benchmark to determine value only when no arm's-length posted prices or contracts for the purchase of like-quality oil exist in the same field, area, or nearby areas where the lessee is selling its oil under non-arm's-length conditions. Actual circumstances in the field or area affect how value is determined.

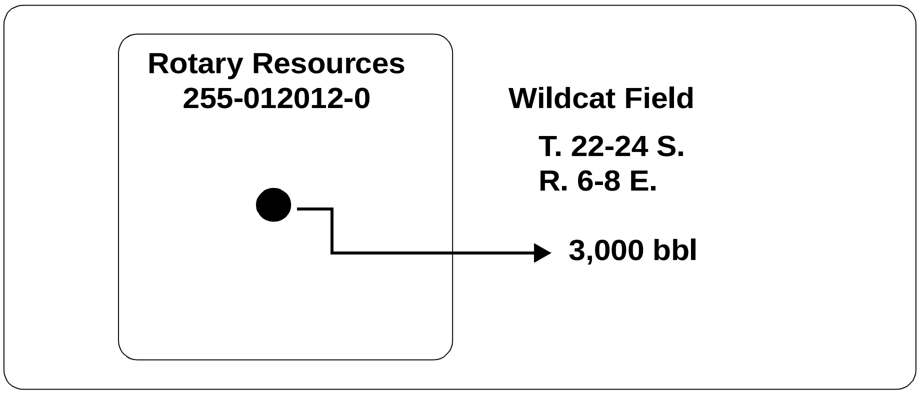
3.2.5 Fifth valuation benchmark: Net-back or other reasonable valuation method

The fifth benchmark for determining of oil value is the net-back method or any other reasonable method to determine value (30 CFR 206.52(c)(5) and 30 CFR 206.102(c)(5)). (The net-back method is defined at 30 CFR 206.51 and 30 CFR 206.101.)

Because circumstances that lead to the use of a net-back or other method cannot be foreseen, no instructions are provided for this valuation method. The applicability of a particular valuation method under the fifth benchmark is determined on a case-by-case basis.

3.2.6 Benchmark valuation examples

Valuation of oil under the benchmark system (that is, oil not sold under arm's-length transactions) is illustrated in figures 3-6 through 3-11.



Total field production: 10,000 bbl oil

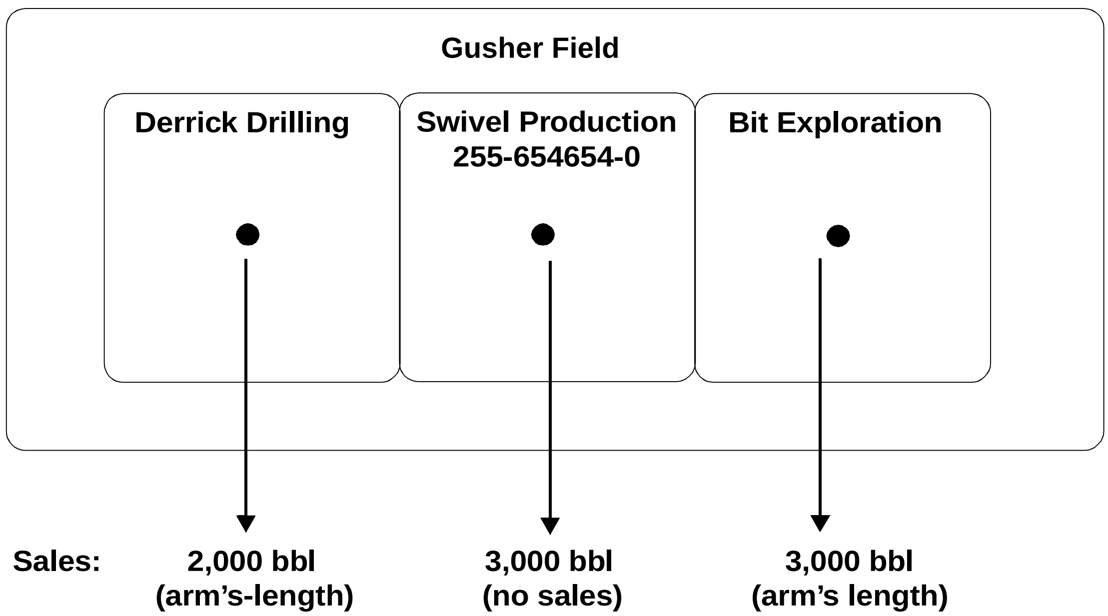
Oil sales by producer:	**Rotary Resources**	**(non-arm's-length)**	**3,000 bbl**
	Derrick Drilling	**(arm's-length)**	**3,000 bbl**
	Bit Exploration	**(arm's-length)**	**2,000 bbl**
	Kelly Corporation	**(arm's-length)**	**2,000 bbl**

Rotary Resources posts for this field and purchases its own production as well as Derrick Drilling's and Bit Exploration's production. Another purchaser buys Kelly Corporation's production under an arm's-length contract.

7,000 bbl of production are purchased arm's-length, of which Rotary purchases 5,000 bbl.

Rotary purchases a significant quantity of like-quality oil from the field. Also, Rotary's posted prices are comparable to prices posted by Kelly's purchaser. Under the criteria of the first benchmark, Rotary may use its posted price to value its portion of production from the Wildcat Field.

FIGURE 3-6. Oil value for a lessee's non-arm's-length sale when that lessee also purchases significant quantities of like-quality oil in the field under arm's-length conditions



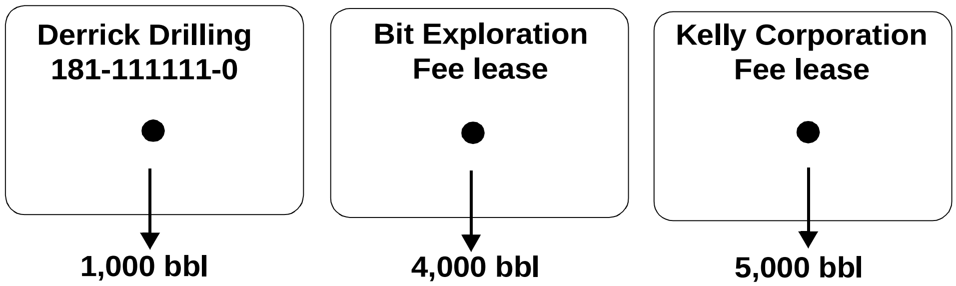
All produced oil is 40 °API.

Swivel Production uses its own production in its nearby refinery and purchases an additional 3,000 bbl arm's-length from Bit Exploration. Mountain Refinery purchases 2,000 bbl arm's-length from Derrick Drilling.

The two arm's-length contract prices are based on Swivel's posted price bulletin.

Swivel purchases a significant quantity of like-quality oil under arm's-length conditions in the Gusher Field. In accordance with the first benchmark, Swivel must use its purchase prices to determine value for its no sales disposition of oil.

FIGURE 3-7. Value of oil not sold by the lessee when that lessee also purchases significant quantities of like-quality oil in the field under arm's-length conditions



Producer	Volume (bbl)	Contract type	Price ($/bbl)
Derrick Drilling	400	arm's-length	$25.25
Derrick Drilling	600	non-arm's-length	25.25
Bit Exploration	4,000	arm's-length	25.50
Kelly Corporation	3,000	arm's-length	25.75
Kelly Corporation	2,000	non-arm's-length	25.10

Both Bit Exploration and Kelly Corporation post for this field; Derrick Drilling does not. Based on purchases in the field, both Bit and Kelly purchase significant quantities of like-quality oil under arm's-length conditions.

Value, arm's-length sales
The gross proceeds accruing to Derrick will generally determine value for royalty purposes.

$$\$25.25 \times 400 \text{ bbl} = \$10{,}100.00$$

Value, non-arm's-length sales
Because Derrick does not post, value is determined under the second benchmark. Derrick must use the arithmetic average to determine value.

$$\frac{(\$25.50 + \$25.75)}{2} = \$25.63$$

Value for royalty purposes is the arithmetic average price times the volume produced.

$$\$25.63/\text{bbl} \times 600 \text{ bbl} = \$15{,}378.00$$

FIGURE 3-8. Oil value for a lessee's non-arm's-length sale using the arithmetic average of posted prices used in arm's-length purchases in the field

Rotary Resources
046-987654-0

Wildcat Field

10,000 barrels of oil are produced from this lease in December.

- **7,000 bbl** — **Sold arm's-length to Kelly Corporation at Kelly's posted price of $25.00/bbl**
- **3,000 bbl** — **Burned to produce steam**
  - **80%** — **Steam injected back into wells to stimulate production**
  - **20%** — **Steam diverted to steam turbine to generate electricity**
    - **60%** — **Electricity used on the lease**
    - **40%** — **Electricity sold to High Voltage Power Company**

Production sold to Kelly Corporation and production used to generate the electricity that is sold to High Voltage Power Company is royalty bearing.

<u>Production sold to Kelly:</u>

The gross proceeds accruing to Rotary Resources will generally determine value for the 7,000 bbl sold under the arm's-length contract with Kelly.

$$7{,}000 \text{ bbl} \times \$25.00/\text{bbl} = \$175{,}000.00$$

<u>Production used to generate electricity that is sold to High Voltage:</u>

The production used to generate electricity that is sold to High Voltage is not sold under an arm's-length contract. To determine royalty value for this portion of lease production, the lessee must use the benchmark system.

FIGURE 3-9. Determination of value for oil used to generate electricity for sale (1 of 2)

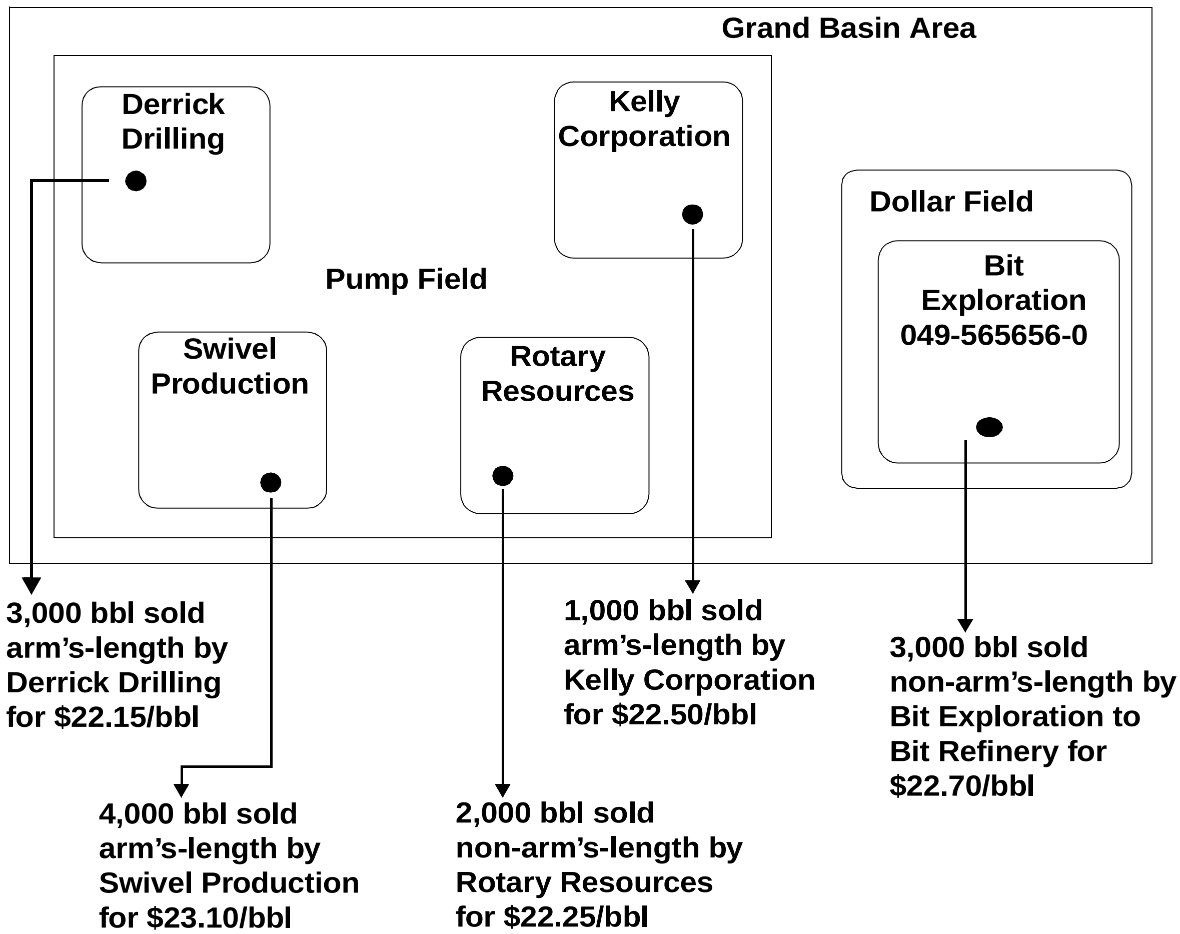
Rotary does not purchase or sell a significant quantity of like-quality oil from the Wildcat Field under arm's-length conditions. Therefore, Rotary cannot use the first benchmark to determine value for its non-arm's-length disposition of oil.

Based on sales in the Wildcat Field, Swivel Production purchases a significant quantity of like-quality oil under arm's-length conditions using its own posted price. There are no other purchasers in the field. Oil used under Rotary's non-arm's-length disposition will be valued using the second benchmark.

Swivel's posted price for oil is $25.15/bbl. Because only one company purchases a significant quantity of like-quality oil, an arithmetic average cannot be calculated. Rotary must use Swivel's posted price to determine the value of oil used to generate electricity during December as follows:

$$3{,}000 \text{ bbl} \times 0.20 \times 0.40 \times \$25.15/\text{bbl} = \$6{,}036.00$$

FIGURE 3-9. Determination of value for oil used to generate electricity for sale (2 of 2)



Bit Exploration is the only producer in the Dollar Field. The Dollar and Pump Fields are the only producing oil fields in the Grand Basin Area.

Bit Exploration sells all oil produced from its lease to its affiliate, Bit Refinery. Bit Refinery uses the oil in its small refinery in the Dollar Field and does not purchase any additional oil for that refinery.

Three producers in Pump Field sell oil under arm's-length conditions to separate buyers. Based on sales from the field, the buyers for Derrick Drilling's and Swivel Production's oil are considered purchasers of significant quantities of like-quality oil in the same area where Dollar Field is located. However, the arm's-length contract prices are not based on posted prices.

FIGURE 3-10. Oil value for a lessee's non-arm's-length sale using the arithmetic average of arm's-length contract prices in a nearby field (1 of 2)

Because Bit Exploration does not post and no posted prices are used in arm's-length purchases or sales in the same field or area, Bit Exploration must use the third benchmark to determine value for oil sold under its non-arm's-length contract. The arithmetic average of Derrick's and Swivel's arm's-length contract prices will determine value for royalty purposes as follows:

$$\frac{(\$22.15 + \$23.10)}{2} = \$22.63$$

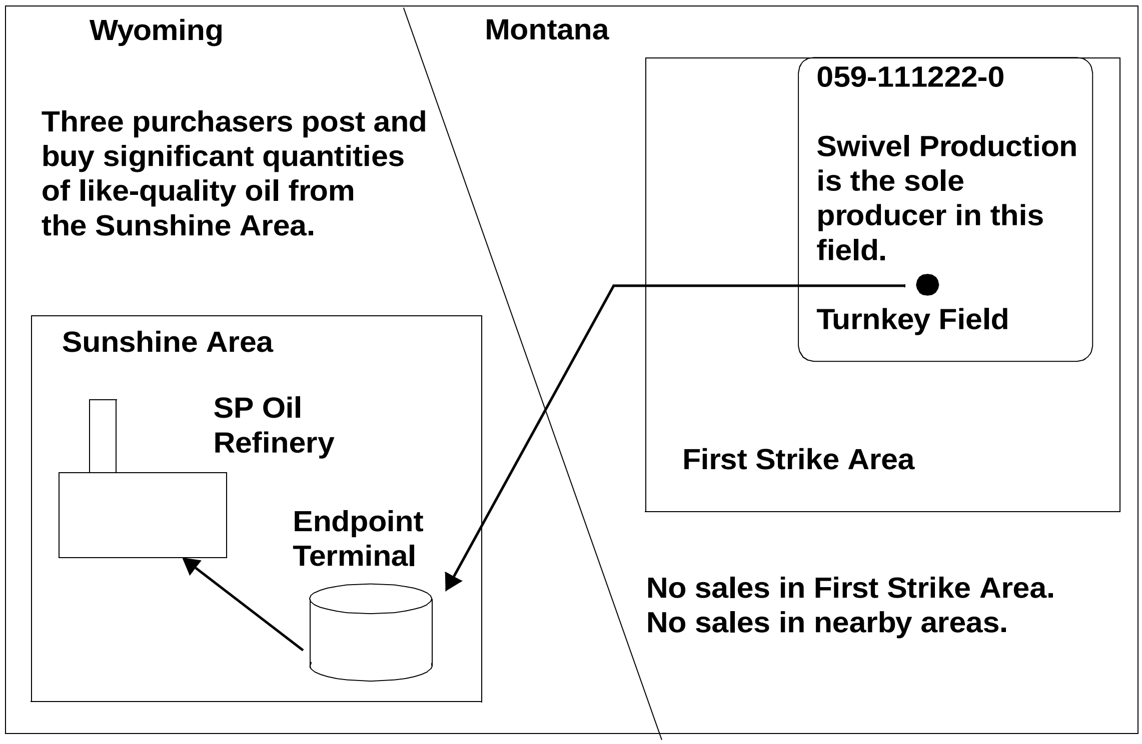
$$\$22.63 \times 3{,}000 \text{ bbl} = \$67{,}890.00$$

This value must be compared to the gross proceeds received by Bit Exploration under its non-arm's-length contract:

$$\$22.70 \times 3{,}000 \text{ bbl} = \$68{,}100.00$$

In this example, the gross proceeds accruing to Bit Exploration are greater than the value determined under the third benchmark. Therefore, Bit Exploration must report the gross proceeds received under its non-arm's-length contract as the value for royalty purposes.

FIGURE 3-10. Oil value for a lessee's non-arm's-length sale using the arithmetic average of arm's-length contract prices in a nearby field (2 of 2)



Because no posted prices or contracts are used in arm's-length purchases of significant quantities of like-quality oil in the field, area, or nearby areas where lease 059-111222-0 is located, Swivel Production cannot use the first three benchmarks to determine value.

No arm's-length spot sales exist in the same field or area where the lease is located. Therefore, under the fourth benchmark, Swivel must use other relevant matters or information concerning circumstances unique to operations on this lease or the salability of the oil to determine value.

To apply the fourth benchmark, Swivel could use the arithmetic average of the posted prices used in the Sunshine Area to determine value for oil produced from the Turnkey Field. If appropriate, Swivel may file for a transportation allowance.

FIGURE 3-11. Oil value for a lessee's non-arm's-length sale based on other relevant matters or information particular to the lease

3.3 Oil Exchange Agreements

An exchange agreement for oil is an agreement for the delivery of oil at a certain location by one party in exchange for the delivery of oil at another location by a second party. The form of an exchange agreement varies widely, depending on the relationship between the two delivery points and the purpose of the agreement. If the two delivery points are on the same pipeline system, the agreement may represent nothing more than a transportation arrangement. By contrast, the delivery points may not be physically connected by the same pipeline system, and the exchange agreement may represent multiple sales or other dispositions under one contract.

The valuation of oil under an exchange agreement depends on whether the oil is actually sold under the agreement or is subject to other dispositions. MMS recognizes three types of exchange agreements for valuation purposes.

In the **first type** of exchange agreement, the lessee's oil is delivered at one point on a pipeline or pipeline system and the same volumes, theoretically, are redelivered at another point downstream on the same system.

A commodity price may or may not be specified in the agreement. If a commodity price is specified, the agreement provides that a price is paid to one party at one point and the same price plus a location differential is paid to the second party at another exchange point.

If a commodity price is not specified, the agreement provides only for payment of the location differential. The location differential specified in the agreement is essentially a transportation charge.

In both cases, the pipeline is obligated to return the oil to the lessee. No sale takes place at the exchange points, and the only consideration passing between the parties is payment for transportation services. Royalty value is:

- Determined at the first sales point at or beyond the downstream exchange point,
- Based on whether the sale is arm's-length or non-arm's-length, and
- Never less than the lessee's gross proceeds.

The lessee's reasonable, actual costs of transporting the oil are eligible for a transportation allowance.

In the **second type** of exchange agreement, the pipeline system carrying the oil exchanged at one location is separate and distinct from the pipeline system carrying the oil exchanged at the second location. The lessee relinquishes possession and title to its oil at the first point of exchange and acquires possession and title to other oil at the second point of exchange.

A commodity price may or may not be specified in the agreement, but no consideration is paid apart from a quality and/or location differential. The exchange of oil under this type of agreement is considered a disposition of lease production but not a sale under an arm's-length contract.

If the oil is not sold after the initial exchange, royalty value is determined under the non-arm's-length benchmark system at the first point of exchange where the lessee relinquishes title to its Federal or Indian oil. If the lessee sells the oil after the exchange, the royalty value is:

- Based on the total consideration received by the lessee from both the exchange and the subsequent sale,
- Based on whether the sale is arm's-length or non-arm's-length, and
- Never less than the lessee's gross proceeds.

The lessee's reasonable, actual costs of transporting the oil are eligible for a transportation allowance.

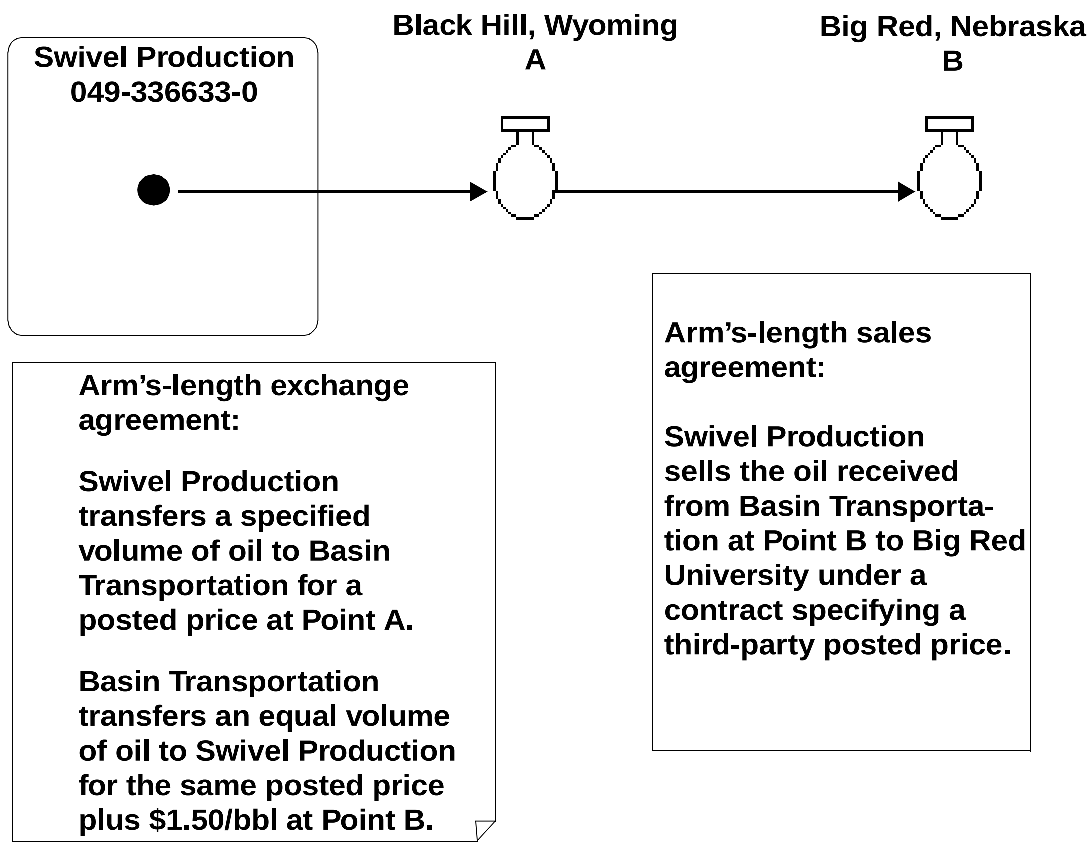
In the **third type** of exchange agreement, the lessee relinquishes title to, and receives consideration for, its oil at one exchange point. The lessee then receives title to, and pays consideration for, oil at a second exchange point. The two exchange points may or may not be physically connected by the same pipeline system. Title to the oil may be transferred at the initial exchange point, and a price may be specified in the agreement.

Because the agreement is conditioned on the lessee's purchase of oil at a subsequent exchange point, the value specified in the exchange agreement does not necessarily reflect the total consideration received for the oil. Royalty value at the initial exchange point is:

- Based on the total consideration ultimately received for the oil (including any premiums received for sales before, at, or beyond the subsequent exchange point),
- Based on whether the post-exchange sale is arm's-length or non-arm's-length, and
- Never less than the lessee's gross proceeds.

The lessee's reasonable, actual costs of transporting the oil are eligible for a transportation allowance.

Figures 3-12, 3-13, and 3-14 illustrate valuation of oil under the three types of exchange agreements recognized by MMS.

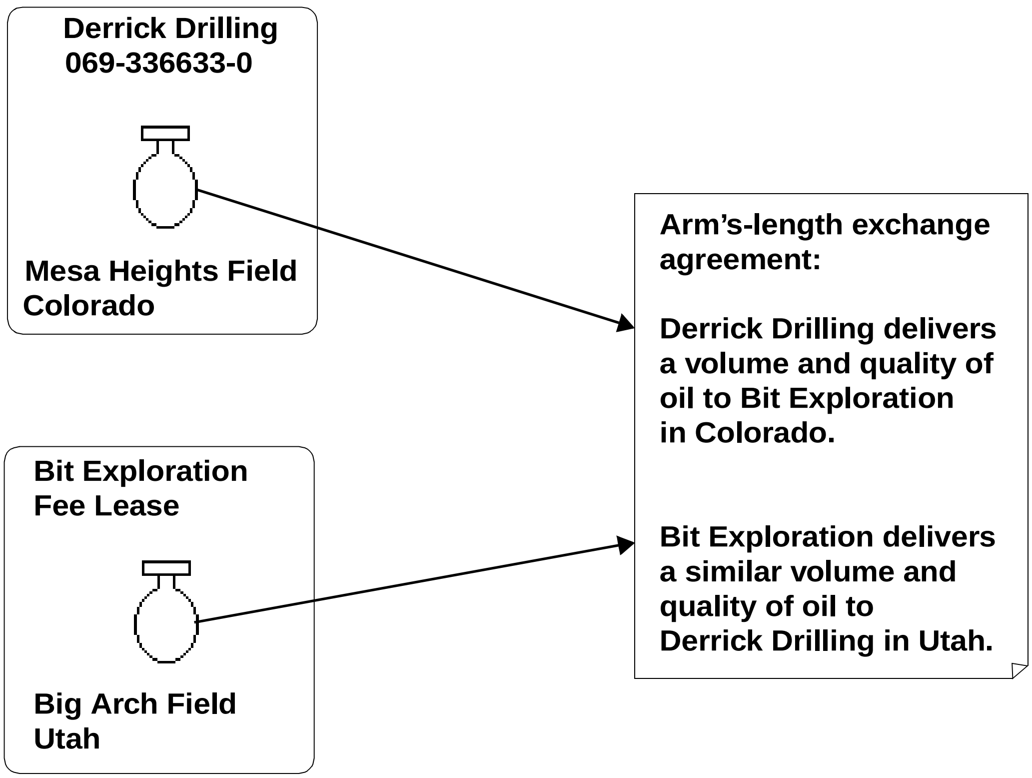


The only consideration passing between Swivel Production and Basin Transportation is a premium for transportation of $1.50/bbl.

The value of the oil is determined based on the arm's-length contract price Swivel receives from Big Red University.

Swivel may also claim a transportation allowance of $1.50/bbl as specified in the exchange agreement and any actual costs incurred to move the oil from the lease to Point A (see ch. 5, "Oil Transportation Allowances").

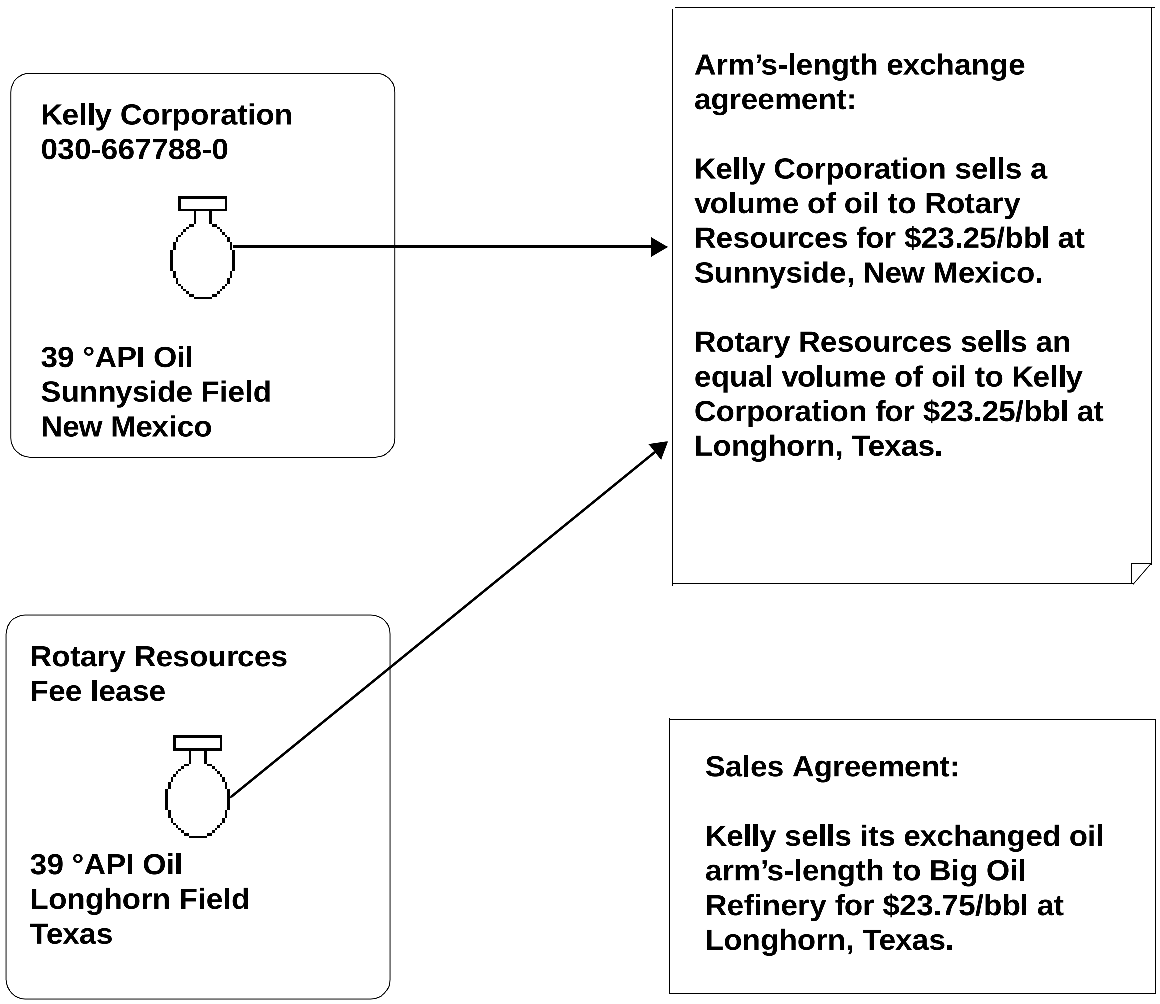
FIGURE 3-12. Determination of oil value under an exchange agreement where the consideration paid is solely for transportation purposes



No price is specified in the exchange agreement, and no consideration is paid for the exchange of oil.

The exchange of oil is not considered a sale under an arm's-length contract, and the value of oil produced from Derrick Drilling's lease is determined at the first point of exchange (Mesa Heights, Colorado) using the benchmark system.

FIGURE 3-13. Determination of oil value under an exchange agreement where a volume exchange occurs and no consideration is paid



Royalty value for production from Kelly Corporation's lease in New Mexico is determined by the arm's-length sales price of $23.75 to Big Oil Refinery at Longhorn, Texas. This represents the total consideration paid for the oil.

If Kelly Corporation incurs reasonable, actual costs to transport the oil, those costs are eligible for a transportation allowance.

FIGURE 3-14. Determination of oil value under an exchange agreement where actual consideration is paid to the lessee on delivery

3.4 Special Oil Valuation Situations

Some situations involving oil valuation require additional consideration in determining the value of oil for royalty purposes. These situations include instances where the oil produced was altered, either physically or chemically, prior to sale or was sold under contracts that use nontraditional pricing mechanisms.

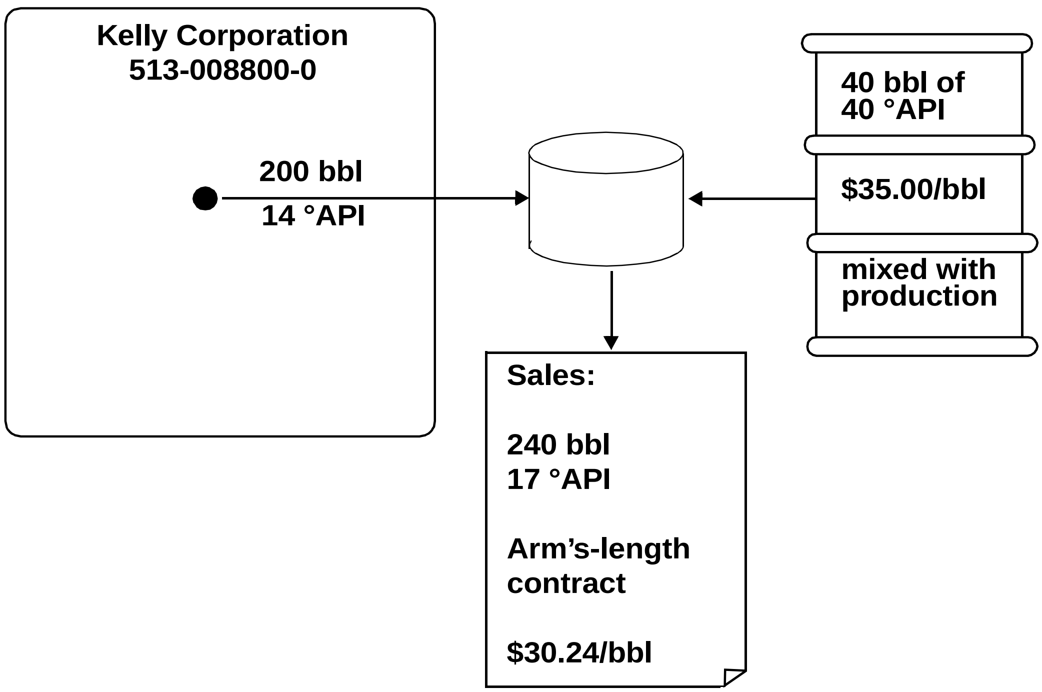
3.4.1 Oil blending for quality enhancement

In some situations, low-grade crude oil cannot be marketed as it comes from the ground. To place the production in marketable condition, lessees may choose to enhance the physical or chemical quality of the low-grade "native" oil by blending it with a higher grade oil purchased elsewhere. Blending occurs at the surface after the native oil is produced.

Value cannot be less than the gross proceeds accruing to the lessee for the sale or other disposition of lease production in marketable condition. However, in cases where low-grade lease (native) oil is blended with a higher grade oil to meet market conditions, the lessee's gross proceeds for the sale of the blended stock will reflect the contribution of the higher grade oil.

Accordingly, the lessee's gross proceeds, as determined by the sales price of the blended stock, must be adjusted to compensate for the contribution of the higher grade oil. This adjustment is performed by subtracting the **cost** of the higher grade oil used in the blending process. The resulting figure reflects the contribution of the low-grade lease oil to the sales price of the blended product, and thus reflects the value of the low-grade oil as adjusted by the quantity and quality of the higher grade blended oil (*Davis* v. *Lujan*, District of Wyoming, No. 90-CV-0071-V, April 29, 1991).

Figure 3-15 illustrates valuation for lease oil that has been blended for quality enhancement. The lessee must maintain all documentation on the oil used for blending to properly account for the native lease oil.



Kelly Corporation is lessee and operator of a Federal well that produces 14 °API gravity oil. Kelly purchases oil off-lease and mixes this oil at the surface with lease production to enhance its quality.

The value of production from this well is calculated as follows:

240 bbl	×	**$30.24/bbl**	**=**	**$7,257.60**
40 bbl	×	**$35.00/bbl**	**=**	**$1,400.00**
			=	
$7,257.60	**-**	**$1,400.00**	**=**	**$5,857.60**

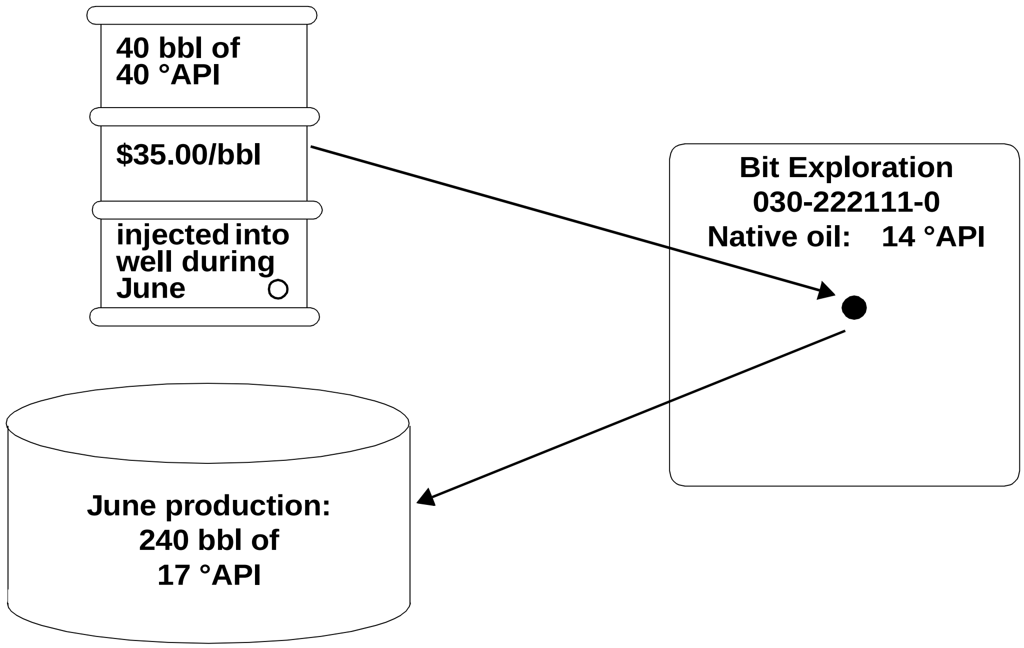
FIGURE 3-15. Determination of value for lease oil that has been blended at the surface for quality enhancement purposes

3.4.2 Load oil

Load oil is oil that is injected into the wellbore for wellbore stimulation, workover, chemical treatment, or other production purposes (30 CFR 206.51 and 30 CFR 206.101). Load oil is not considered oil used for quality enhancement. Instead, MMS considers load oil as a production expense in which the Federal or Indian royalty owner does not share.

When load oil is injected into a well to increase its production, the oil subsequently produced from the well is a mixture of native and load oil. The lessee may recover a volume equal to the volume of load oil injected during the month the oil is recovered without incurring a royalty obligation on that load oil. Royalty value is based on the total volume produced from the well, less the volume of the injected load oil. The load oil is considered to be the first oil recovered from the well for the same month.

Figure 3-16 illustrates value determination for lease oil where load oil has been injected into the wellbore to stimulate or enhance production.



Bit Exploration injects 40 bbls of 40 °API gravity oil into the well during June. June production is 240 bbl of 17 °API gravity oil.

Bit sells all 240 bbl under an arm's-length contract for a price of $29.54/bbl.

The first 40 bbl recovered from the well are considered to be the injected oil and are not royalty bearing.

The remaining 200 bbl are considered native oil and are subject to royalty.

Value for royalty purposes: $\quad$ **200 bbl × $29.54/bbl = $5,908.00**

FIGURE 3-16. Determination of lease oil value where load oil has been injected into a well to stimulate or enhance production

3.4.3 Oil sold under contracts using daily weighted-average prices

The sales value of oil purchased from tank storage is generally determined by posted prices in effect at the time the run ticket is generated. In these situations, the gross proceeds accruing to the seller are based on the posted price in effect on the day the purchaser takes possession of the oil.

However, some contracts establish the purchase price for oil as the weighted average of daily posted prices for the month. This pricing mechanism results in a single monthly price for a given grade of oil. The mechanism is designed to normalize the daily fluctuations sometimes experienced for posted prices. Normally, a purchaser uses its own posted prices to calculate the daily weighted-average price.

Under the daily weighted-average price method, the sales value of purchased oil is determined at the end of the month, based on the weighted average of the posted prices for that month. This value is applied to all oil sold in a particular month, regardless of the posted price in effect on the date the oil was actually sold.

If the oil was actually purchased on days when the highest posted prices were in effect, the daily weighted-average method yields gross proceeds that are lower than those generated by the contemporary postings. Conversely, if oil was purchased on days when the lowest posted prices were in effect, the weighted-average price method yields gross proceeds that are higher than those generated by the contemporary postings.

Arm's-Length Contracts. The gross proceeds accruing to the lessee under an arm's-length contract are generally accepted as value for royalty purposes unless those prices do not represent reasonable value because of lessee misconduct or because the lessee has breached its duty to market the oil to the mutual benefit of the lessee and the lessor.

Although the daily weighted-average price method may yield gross proceeds that are lower than those generated by the contemporary postings, this lower price does not necessarily represent lessee misconduct or breach of the lessee's marketing duty. Thus, if a lessee executes an arm's-length contract with an oil purchaser that uses the daily weighted-average price method, the lessee's gross proceeds are generally accepted as value for royalty purposes.

Non-Arm's-Length Contracts. Value for non-arm's-length purchases must be determined under the benchmark system, regardless of which pricing mechanism is used to value production. The lessee's daily weighted-average price under its non-arm's-length contract is acceptable under the first benchmark if:

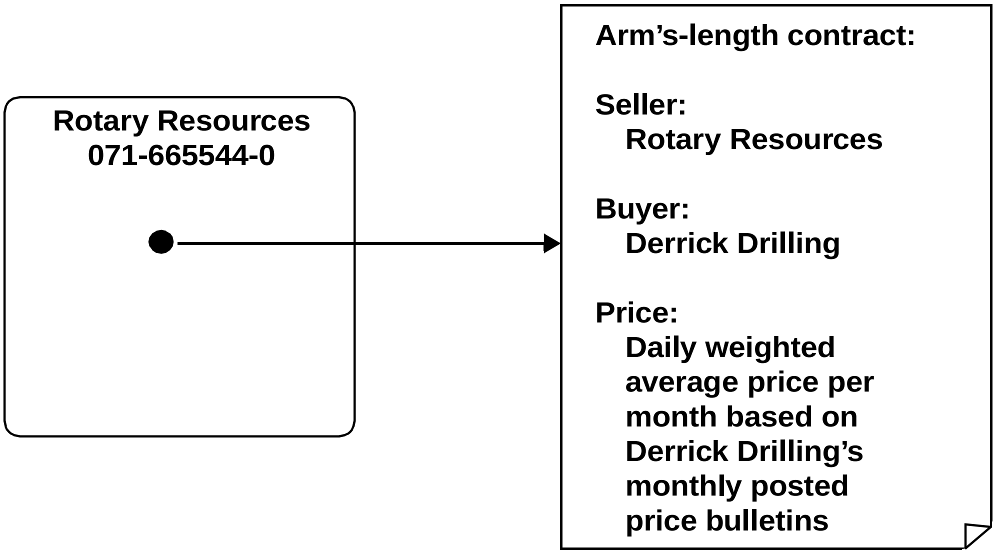
- A lessee selling oil under non-arm's-length conditions uses the daily weighted-average price method in other arm's-length transactions for the purchase of significant quantities of like-quality oil in the same field,

  and

- That price is comparable to other posted or contract prices used in arm's-length transactions for purchases of significant quantities of like-quality oil in the same field.

If the lessee's price does not meet the requirements of the first benchmark, the lessee must use the next applicable benchmark to determine value.

Figure 3-17 illustrates value determination for oil sold under a daily weighted-average price contract.



Based on Derrick Drilling's posted prices for the field, the daily weighted average price is calculated as follows:

Date	Posted price	Days at posting	Weighted value
06/01/91	$19.50	9	$175.50
06/10/91	$18.25	3	54.75
06/13/91	$18.25	11	200.75
06/24/91	$18.50	3	55.50
06/27/91	$19.00	4	76.00
		30	$562.50

Daily weighted-average price:

$$\frac{\$562.50}{30} = \$18.75$$

Rotary Resources sells 1,000 bbl of oil on 06/10/91 and 3,000 bbl on 06/24/91 to Derrick Drilling.

Value for royalty purposes: $4{,}000\ \text{bbl} \times \$18.75/\text{bbl} = \$75{,}000.00$

FIGURE 3-17. Determination of value for oil sold under a daily weighted-average price contract

3.4.4 Oil sold under fixed-price contracts

Oil purchase contracts are generally based on posted prices that fluctuate daily in response to both national and international market conditions. To mitigate the effect of volatile oil prices and to provide a steady source of oil, a few purchasers are buying oil under contracts that establish a single, fixed price for oil during a specified period. Generally, these contracts involve low-quality oil located in remote fields where posted prices do not exist and purchasers are few or nonexistent. The fixed-price contracts are designed to ensure that production of this oil is sustained in a volatile and uncertain market.

Under a typical oil sales contract that is based on posted prices, oil value for a specific month is calculated by multiplying the volume of oil removed from the lease on a particular day by the posted price in effect on the same day. If oil sales from a lease occur several days during the month, each daily sale will be valued based on the price posted for that day. By contrast, under the fixed-price contract, the entire volume of oil removed from the lease during a specific month is valued at one single price.

Arm's-Length Contracts. In situations where the lessee enters into a fixed-price contract because of remoteness of the field, scarcity of purchasers, lack of posted prices, low oil quality, or unstable market conditions, MMS assumes that the lessee is making every effort to market the production to the mutual benefit of the Federal or Indian lessor unless a breach of duty or misconduct is demonstrated. Therefore, MMS generally views the gross proceeds received under an arms-length, fixed-price contract as value for royalty purposes, even though such value may be higher or lower than prices posted or negotiated for other oil in the general area.

Non-Arm's-Length Contracts. Value for non-arm's-length purchases must be determined under the benchmark system, regardless of which pricing mechanism is used to value production. The lessee's price under its non-arm's-length fixed-price contract is acceptable under the first benchmark if:

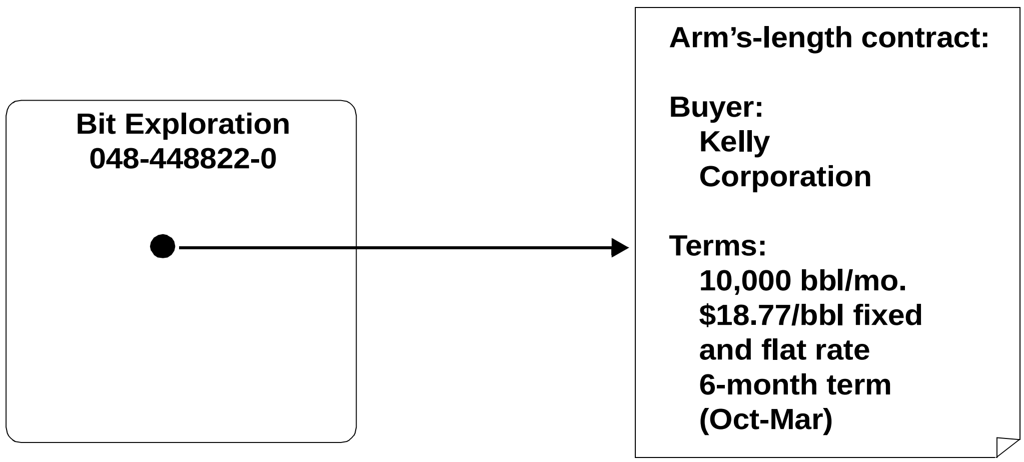
- A lessee selling oil under non-arm's-length conditions uses the fixed-price method in other arm's-length transactions for the purchase of significant quantities of like-quality oil in the same field,

  and

- That price is comparable to other posted or contract prices used in arm's-length transactions for purchases of significant quantities of like-quality oil in the same field.

If the lessee's price does not meet the requirements of the first benchmark, the lessee must use the next applicable benchmark to determine value.

Figure 3-18 illustrates value determination for oil sold under a fixed-price contract.



The oil produced is classified as sour crude.

Other production from the field is sold under typical oil sales contracts that are based on posted prices.

Bit Exploration entered into the fixed-price contract because of concern that sour oil prices might soften during the winter months due to less demand for asphalt.

Prices under the fixed-price contract could be higher or lower than prices under typical oil sales contracts in the area. Because the short duration of the contract enables Bit to renegotiate at market-sensitive levels within a reasonable period of time, if prices under this contract were lower than prices paid under typical oil sales contracts in the field, MMS would not view the lower prices to be a result of lessee misconduct or breach of duty.

Value for royalty purposes: **10,000 bbl $\times$ \$18.77/bbl = \$187,700.00**

FIGURE 3-18. Determination of value for oil sold under a fixed-price contract

3.5 Major Portion Analysis for Indian Oil Leases

The valuation of oil produced from Indian leases is subject to the same procedures, conditions, and limitations that apply to the valuation of oil produced from Federal leases. However, most Indian lease terms provide for, at the discretion of the Secretary of the Interior, a major portion analysis to determine the value of oil for royalty purposes.

For those Indian leases requiring consideration of the major portion, the value of the oil is the greater of the value determined by major portion analysis (known as the majority price) or the value determined based on the actual disposition of the oil (arm's-length or non-arm's-length) (30 CFR 206.52(i)). The majority price is defined as the highest price paid or offered at the time of production for the major portion of oil produced from the same field or area (30 CFR 206.52(a)(2)(ii)).

Compute the majority price as follows:

STEP 1. Array all arm's-length sales prices and corresponding volumes from the highest price at the top to the lowest price at the bottom.

STEP 2. Starting from the bottom, sum the cumulative percentages that each volume represents of the total volume.

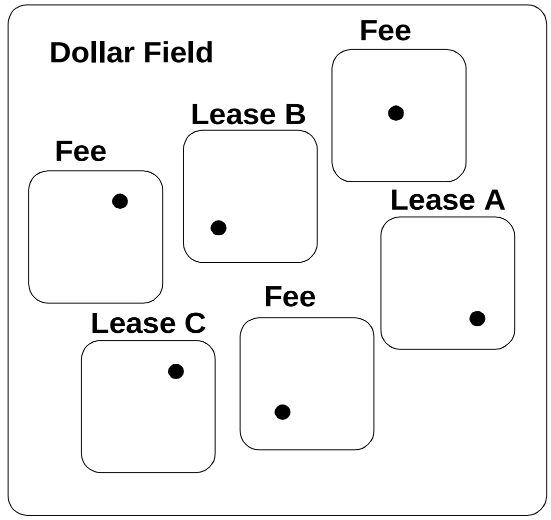
The majority price is that price at which 50 percent (by volume) plus 1 barrel (bbl) of oil (starting from the bottom) is sold.

Figure 3-19 illustrates calculation of a majority price for Indian oil.

15,00 bbl are produced from the Dollar Field.

10,000 bbl are sold under arm's-length contracts.

Leases A, B, and C are Indian leases. All three leases require calculation of a majority price.



Majority price calculation*

Contract	Volume (bbl)	Price ($/bbl)	Summation
Fee lease	2,000	$20.00	100%
Lease A	1,000	19.50	80
Fee lease	3,500	19.25**	70
Lease B	2,000	18.75	35
Lease C	500	18.50	15
Fee lease	1,000	18.25	10
	10,000		

* Only arm's-length prices are used.
** The price at which 50 percent plus 1 bbl of oil was sold.

Determination of value

The majority price calculated for the Dollar Field is $19.25/bbl.

Lessee A would base royalty value on its arm's-length price of $19.50/bbl.

Lessee B and C would base their royalty value on the calculated majority price.

FIGURE 3-19. Majority price calculation for Indian oil leases

4. Gas Valuation

This chapter describes specific methods and procedures for valuing gas and constituent products produced from Federal and Indian lands. In addition to the general requirements discussed in chapter 2, the lessee must follow the procedures outlined in this chapter for gas valuation. The valuation standards for Federal and Indian gas are based primarily on whether the gas is processed or unprocessed, and criteria are included for distinguishing these two types of gas for valuation purposes. The valuation of gas disposed of under special contracts is also covered in this chapter, as well as the requirements for performing accounting for comparison (dual accounting) to be used in valuing both Federal and Indian gas and the major portion analysis for valuing Indian gas.

NOTE

MMS published new Indian gas valuation regulations in the *Federal Register* on August 10, 1999 (64 FR 43506). The revised regulations, which became effective on January 1, 2000, add alternative valuation methods to the March 1, 1988, regulations to ensure that Indian lessors receive maximum revenues from their mineral resources as required by the unique terms of Indian leases and MMS's trust responsibility to Indian lessors.

For valuation of Indian gas production from Tribal or allotted oil and gas leases (except leases on the Osage Indian Reservation) occurring on or after January 1, 2000, lessees must use the criteria contained in this new regulation.

A copy of this new regulation can be found on MMS's web page at www.mrm.mms.gov, under the Tribal Services, Index Zone Prices buttons.

MMS will prepare an update to this payor handbook with specific instructions on how to determine value under the new Indian gas valuation regulations.

4.1 Unprocessed Gas

Unprocessed gas is gas at the outlet of normal lease production equipment such as dehydration and compression facilities. Unprocessed gas may contain liquefiable hydrocarbons and/or other nonhydrocarbon substances necessitating eventual processing, or it may be relatively free of these components and require little or no additional treatment.

Gas produced from **Federal** leases is valued as unprocessed gas under any one of the following conditions:

1. The gas is not physically processed for the recovery of gas plant products (30 CFR 206.152(a)(1) and 30 CFR 206.172(a)(1)).

2. The gas is processed but is sold prior to processing under an arm's-length contract, and the lessee retains no rights to the gas after the point of sale (30 CFR 206.152(a)(1) and 30 CFR 206.172(a)(1)).

3. The gas is produced on or after November 1, 1991, and the lessee's **arm's-length** contract for the sale of gas prior to processing provides for the value to be determined based upon a percentage of the purchaser's proceeds resulting from processing the gas, known as a percentage-of-proceeds (POP) contract (56 FR 46527, September 13, 1991).

4. The gas is processed, but the value is determined based on unprocessed gas under accounting for comparison requirements (30 CFR 206.155(a) and 30 CFR 206.175(a)).

If the lessee reserves the rights to processing and exercises those rights, the gas is valued as processed gas (see "Processed Gas" on p. 4-34). Also, the gas is valued as processed gas if the lessee has a POP contract and either of the following conditions apply:

- The contract is **non-arm's-length**.

- The production occurred before November 1, 1991.

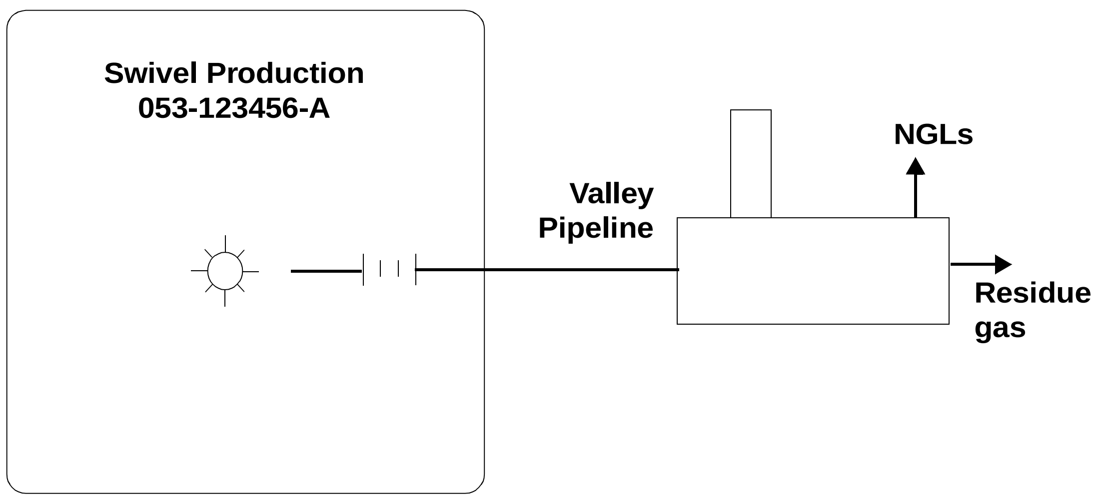
"Gas Disposed of Under Special Contracts or Situations" on page 4-55 provides guidelines for the valuation of gas sold under POP contracts both before and after November 1, 1991.

Gas produced from **Indian** leases is valued as unprocessed gas under any one of the following conditions:

- The gas is not physically processed for the recovery of gas plant products.
- The lease terms do not require dual accounting, in which case the gas is valued as unprocessed gas under any of the conditions for which Federal gas is valued as unprocessed gas.
- Under dual accounting, the value of the unprocessed gas is greater than the value of the processed gas (see "Accounting for Comparison" [dual accounting] on p. 4-90).

The royalty value of unprocessed gas must be calculated on the full volume of gas measured at the point of royalty settlement designated by the BLM for onshore operations and by MMS for offshore operations. Valuation standards are based primarily on whether or not the unprocessed gas is sold under an arm's-length contract. For sales or dispositions under an arm's-length contract, the price established by the contract is usually acceptable for determining value. For sales or dispositions under other than an arm's-length contract, the value is determined under a benchmark system. If applicable, a transportation allowance may be deducted from the value of the unprocessed gas (30 CFR 206.152(a)(2) and 30 CFR 206.172(a)(2)) (see Chapter 6, "Gas Transportation Allowances"). All reported values are subject to being monitored, reviewed, and audited.

Figures 4-1 through 4-5 illustrate how to determine whether gas is valued as processed or unprocessed.

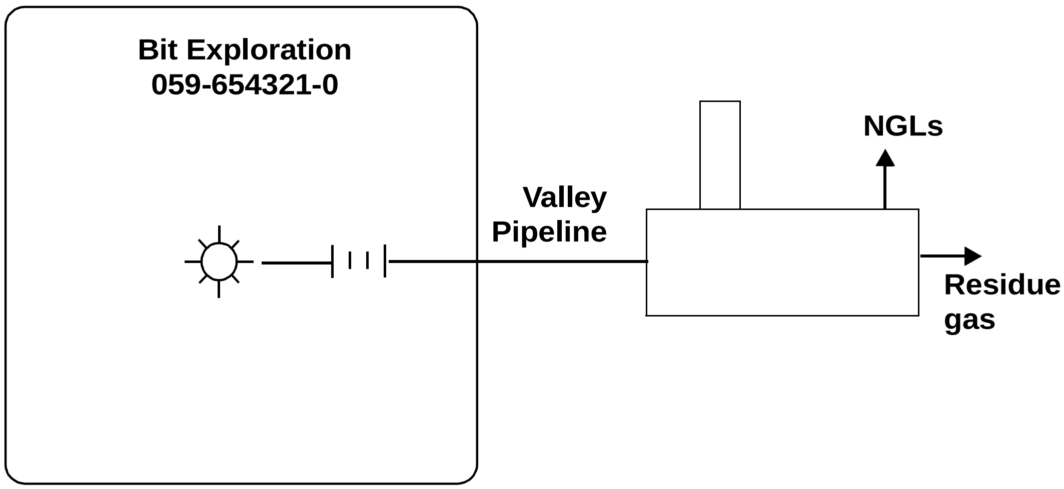


Swivel Production sells gas to Valley Pipeline under an arm's-length wellhead sales contract at a specified price stated in $/MMBtu.

Swivel retains no rights to processing.

Because the gas is sold under an arm's-length contract prior to processing, the gas is valued as unprocessed gas.

FIGURE 4-1. Gas valued as unprocessed: Arm's-length wellhead sales contract specifying price per MMBtu



Bit Exploration sells gas to Valley Pipeline under an arm's-length casinghead gas contract. Bit retains no rights to processing. The price received for the gas is specified in the contract as the liquid value plus the residue gas value.

<u>Liquid value:</u>

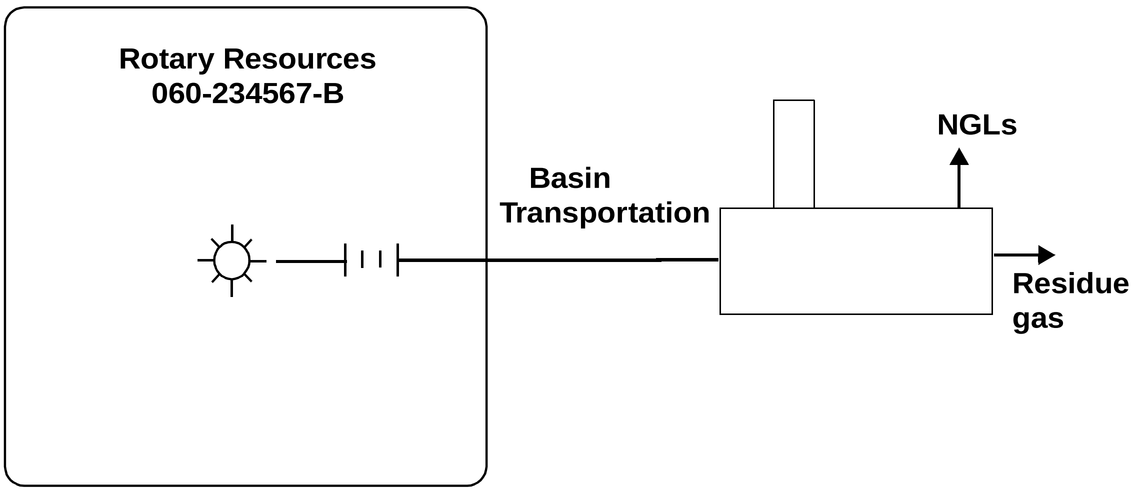
Wellhead Mcf × NGL content (gal/Mcf) × contract price ($/gal)

<u>Residue gas value:</u>

Residue gas (Mcf) × contract price ($/Mcf)

Because Bit sells the gas under an arm's-length contract prior to processing, the gas is valued as unprocessed gas.

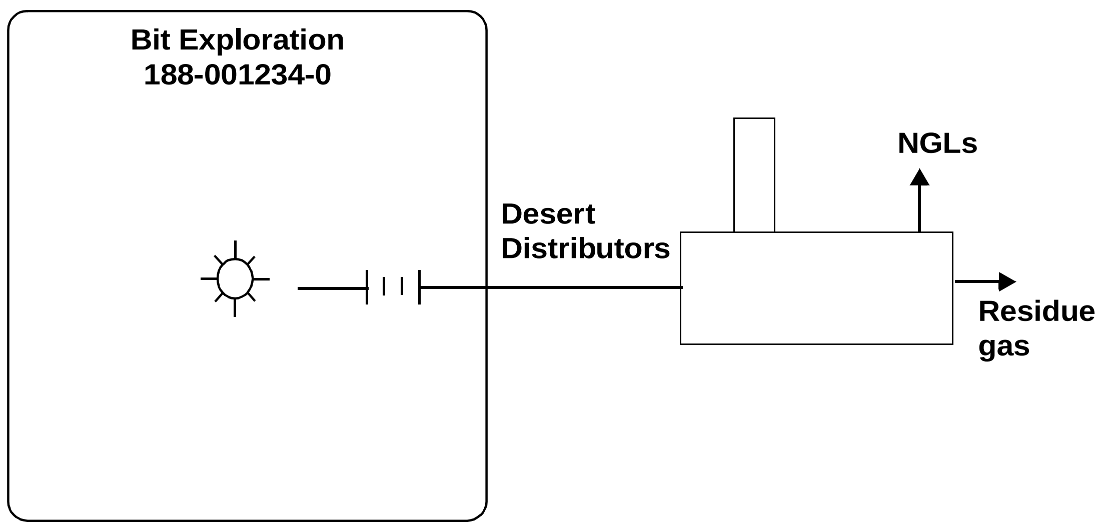
FIGURE 4-2. Gas valued as unprocessed: Arm's-length wellhead sales contract specifying price based on values of residue gas and liquids



Rotary Resources sells gas to Basin Transportation under an arm's-length wellhead sales contract at a specified price in terms of $/MMBtu. Rotary reserves and exercises the right to process the gas for the recovery of NGLs.

The gas is valued as processed gas (see "Processed Gas" on p. 4-34).

FIGURE 4-3. Gas valued as processed: Arm's-length wellhead sales contract where lessee reserves and exercises the processing rights

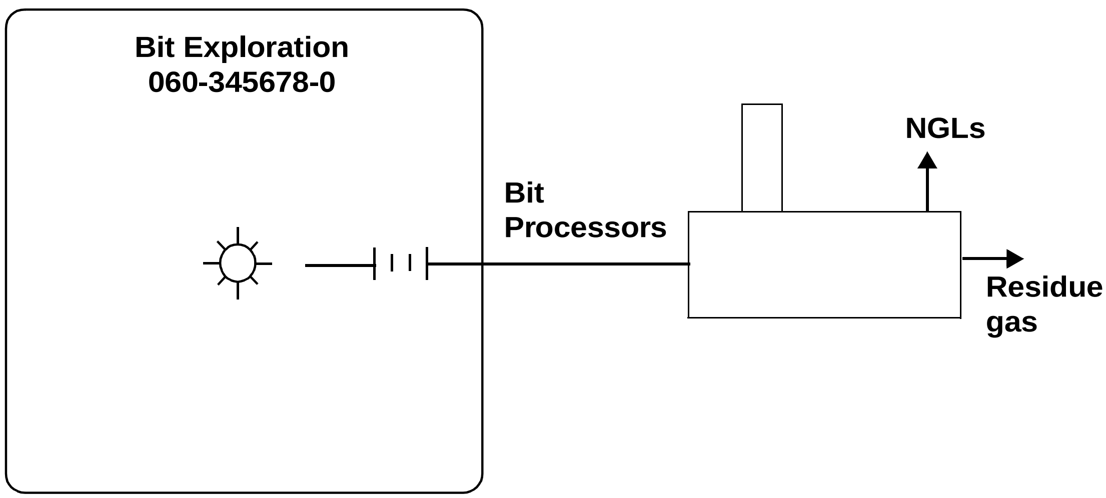


Bit Exploration sells gas to Desert Distributors under an arm's-length POP sales contract.

The gas produced prior to November 1, 1991, is valued as processed gas. The gas produced on or after November 1, 1991, is valued as unprocessed gas.

See "POP contracts" on p. 4-56 for valuation under POP contracts.

FIGURE 4-4. Gas valued as processed or unprocessed: Arm's-length POP contract for production both prior to, and on and after, November 1, 1991



Bit Exploration sells gas to Bit Processors under a non-arm's-length POP contract.

The gas is valued as processed gas.

See "Gas Disposed of Under Special Contracts or Situations" on p. 4-55 for valuation under POP contracts.

FIGURE 4-5. Gas valued as processed: Non-arm's-length POP contract

4.1.1 Valuation of unprocessed gas sold under an arm's-length contract

The value of unprocessed gas sold under an arm's-length contract is generally the gross proceeds accruing to the lessee under the provisions of the contract. Gross proceeds are also used to determine value in those cases where the unprocessed gas is sold by the lessee's marketing affiliate under an arm's-length transaction (30 CFR 206.152(b)(1)(i) and 30 CFR 206.172(b)(1)(i)). The gross proceeds include any payments made to the lessee for placing the unprocessed gas in marketable condition, such as reimbursements for gathering, dehydration, compression, and marketing, plus any reimbursements for those and other services allowed under FERC Order No. 94. Gross proceeds also include any reimbursements for severance or ad valorem taxes (see "Gross proceeds" on p. 2-21 for more information).

However, MMS will not accept arm's-length gross proceeds (or contract prices) as royalty value if:

- The lessee's sales contract does not reflect the total consideration actually transferred either directly or indirectly from the buyer to the seller. If the contract does not reflect total consideration, MMS may require the lessee to determine value for royalty purposes under the benchmarks governing the value of unprocessed gas not sold under an arm's-length contract (30 CFR 206.152(b)(1)(ii) and 30 CFR 206.172(b)(1)(ii)). Value for royalty purposes can never be less than the gross proceeds accruing to the lessee, and those gross proceeds must include any additional consideration required under the contract.

- The lessee's gross proceeds received under the contract do not reflect reasonable value of the production because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to market the production for the mutual benefit of the lessee and lessor. Then MMS requires the gas to be valued under the benchmarks governing the value of unprocessed gas not sold under arm's-length contracts (30 CFR 206.152(b)(1)(iii) and 30 CFR 206.172(b)(1)(iii)). When MMS determines that the value is unreasonable, the lessee is provided an opportunity to justify its valuation method.

The value of unprocessed gas sold under an arm's-length warranty contract may not necessarily be based on the gross proceeds. Rather, MMS will determine value on a case-by-case basis by considering all valuation criteria available (30 CFR 206.152(b)(2) and 30 CFR 206.172(b)(2)). See the guidelines in “Warranty contracts” on page 4-68.

4.1.1.1 Total consideration

If the arm’s-length contract does not set forth total consideration passing directly or indirectly from the buyer to the lessee for the sale of unprocessed gas, the lessee’s gross proceeds may have to be adjusted to reflect the additional consideration (30 CFR 206.152(b)(1)(ii) and 30 CFR 206.172(b)(1)(ii)). In some cases, the contract may not reveal special arrangements between the buyer and the lessee that may affect sales prices. In these situations, the value of the other considerations must be included as part of the gross proceeds accruing to the lessee. For instance, in return for the lessee’s reduced price for gas, the buyer may agree to reduce the cost of services it sells to the lessee, or the lessee may be reimbursed by the purchaser for services that the lessee is obligated to perform at no cost to the lessor.

For example, in the situation described above, the lessee that sold gas at a reduced price under its sales contract and received reimbursement under a separate contract must increase its gross proceeds by the amount of the reimbursement to determine the value of the gas for royalty purposes (reimbursements become part of the consideration paid for the gas).

If the lessee is aware of considerations outside the “four corners” of the contract, it should notify the Royalty Valuation Division of such considerations and the circumstances under which they occur and propose a valuation and/or request valuation guidance. Notification consists of a letter addressed to the Chief, Royalty Valuation Division. See “Important Addresses and Phone Numbers” on page 1-5.

If necessary, the lessee may be required to certify that its arm’s-length contract discloses all of the consideration paid by the buyer, either directly or indirectly, for the gas (30 CFR 206.152(b)(3)and 30 CFR 206.172(b)(3)).

4.1.1.2 Reasonable value

The lessee is obligated to negotiate contracts prudently and receive the best possible price to the mutual benefit of itself and the lessor. Even though a contract may be arm's-length, if MMS determines that the gross proceeds under that arm's-length contract do not reflect a reasonable value because of misconduct between the contracting parties or because the lessee has otherwise breached its duty to market production for the mutual benefit of the lessee and the lessor, MMS requires that the gas be valued under the regulations governing transactions involving other than arm's-length contracts (30 CFR 206.152(b)(1)(iii) and 30 CFR 206.172(b)(1)(iii)). Lessee misconduct or breach of marketing duty may include, but is not limited to, such actions as collusion between the lessee/seller and purchaser, negligence in negotiating contracts, or pricing practices found by a court or regulatory authority to be incorrect or fraudulently manipulated.

If MMS determines the value to be unreasonable, MMS notifies the lessee and gives the lessee an opportunity to provide written information justifying its value.

4.1.1.3 Sales by a marketing affiliate

Under certain circumstances, a lessee may choose to transfer gas produced from a Federal lease to its marketing affiliate. For royalty purposes, a marketing affiliate is an affiliate whose function is to acquire only the lessee's production and to market that production.

In instances where the lessee's affiliate meets the MMS definition of marketing affiliate, unprocessed gas that is transferred to the marketing affiliate and is subsequently sold by the marketing affiliate under an arm's-length contract is valued based on the gross proceeds accruing to the marketing affiliate (30 CFR 206.152(b)(1)(i) and 30 CFR 206.172(b)(1)(i)). If the lessee sells or transfers gas to its marketing affiliate and the marketing affiliate does not subsequently sell the gas under an arm's-length contract, the gas is valued under the benchmarks governing the value of unprocessed gas not sold under an arm's-length contract.

If the lessee transfers gas to an affiliate that also purchases gas from other sources, the affiliate does not qualify as a marketing affiliate for valuation purposes. In this case, the gas is valued under the benchmark system. When gas is transferred to an affiliate without a sales transaction, the value of the gas cannot be less than the gross proceeds received by the affiliate for sale of the gas (30 CFR 206.152(h) and 30 CFR 206.172(h)).

4.1.1.4 Transportation factors

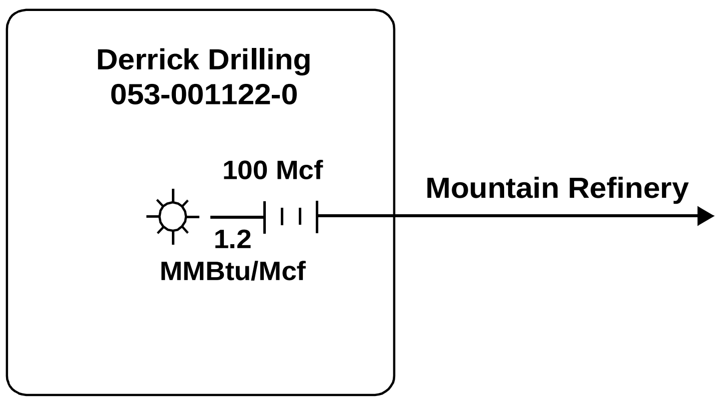
When the lessee's gross proceeds received under an arm's-length contract are reduced by the purchaser to reflect the purchaser's costs of transporting the lessee's unprocessed gas, the amount of the transportation charge is deemed a transportation factor (30 CFR 206.157(a)(5) and 30 CFR 206.177(a)(5)). Transportation factors represent the amount by which a contractually specified price is reduced for costs of moving gas production to a location away from the point of title transfer at which the purchaser believes the value of the gas (the contractually specified price) can best be defined. Because the lessee incurs no out-of-pocket expenses for the costs of transportation, transportation factors are not considered a transportation allowance. For valuation purposes, the gross proceeds received by the lessee for gas sold under its arm's-length contract (net of the transportation factor) establishes value for that gas. For reporting purposes, the lessee enters only one line on Form MMS-2014, representing the gross proceeds net of the transportation factor.

Transportation factors may not exceed 50 percent of the value of the unprocessed gas at the sales point without MMS approval. If the lessee's transportation factor exceeds the 50-percent limit, the lessee must notify the Royalty Valuation Division in writing and request and receive approval to exceed the 50-percent limit prior to paying royalties based on its gross proceeds. See "Important Addresses and Phone Numbers" on page 1-5.

For additional information on gas transportation factors, see "Transportation factors" on page 6-4.

4.1.1.5 Arm's-length valuation examples

Figures 4-6 through 4-12 illustrate valuation of unprocessed gas sold under arm's-length contracts. Values and allowances reported on Form MMS-2014 are shown in boxes.

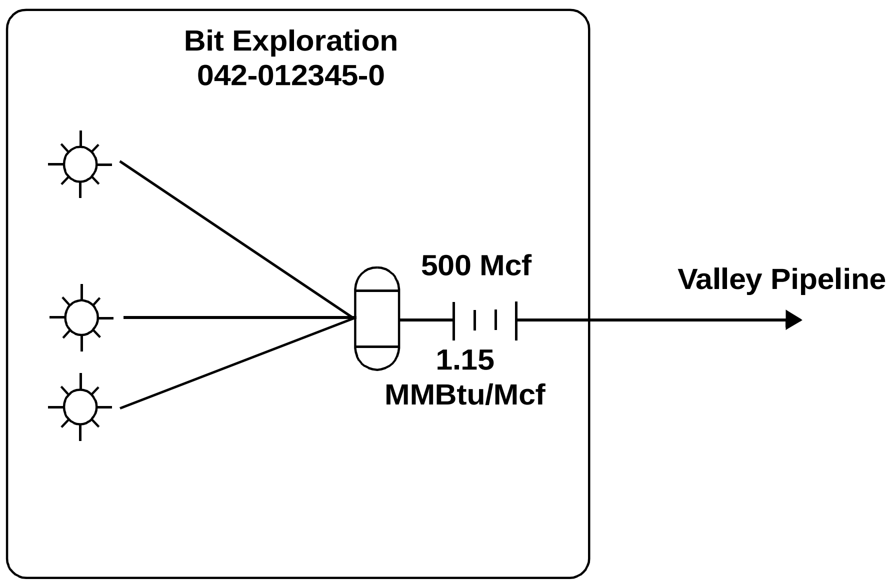


Derrick Drilling sells gas to Mountain Refinery under an arm's-length contract for $1.83/MMBtu.

Value is based on the gross proceeds.

Value: **100 Mcf** × **1.2 MMBtu/Mcf** × **$1.83/MMBtu** = $\boxed{\textbf{\$219.60}}$

FIGURE 4-6. Valuation of unprocessed gas sold under an arm's-length contract

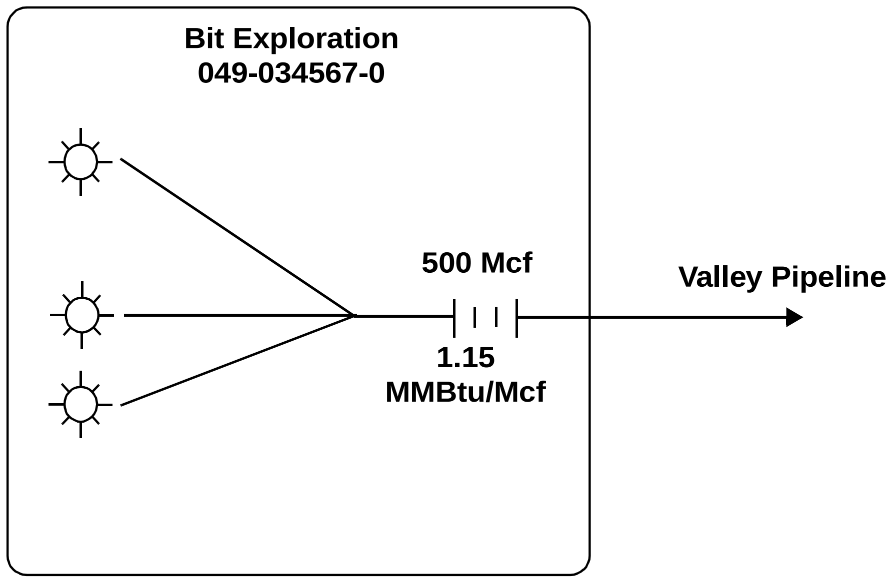


Bit Exploration sells gas at a central lease meter to Valley Pipeline under an arm's-length contract. The price received for the gas is $1.60/MMBtu plus a $0.25/MMBtu gathering and dehydration reimbursement.

Value is based on gross proceeds including reimbursements.

Value: **500 Mcf** × **1.15 MMBtu/Mcf** × **$1.85/MMBtu** = $\boxed{\textbf{\$1,063.75}}$

FIGURE 4-7. Valuation of unprocessed gas sold under an arm's-length contract that provides for gathering and dehydration reimbursements



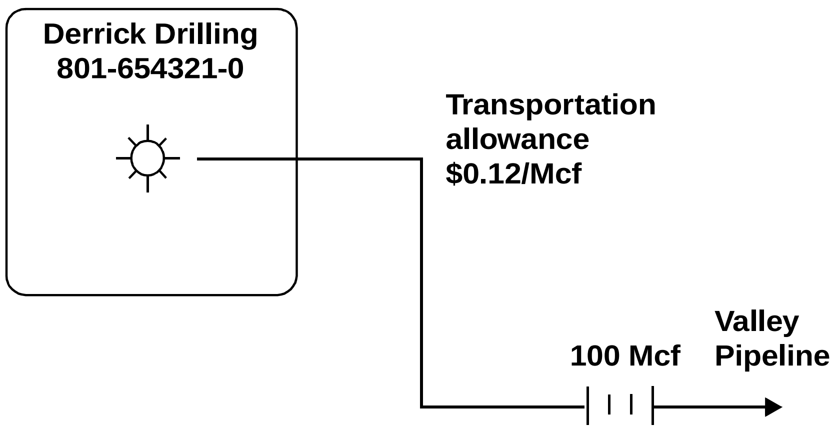
Bit Exploration sells gas at a central lease meter to Valley Pipeline under an arm's-length contract at a price of $1.60/MMBtu. Bit also has a construction agreement with Valley where Valley pays Bit $100.00 per month until payout for the costs of building the gathering system to Valley's main line.

Value is based on gross proceeds, including payments under other agreements for services required to place the gas in marketable condition.

Value:

$$(\textbf{500 Mcf} \times \textbf{1.15 MMBtu/Mcf} \times \textbf{\$1.60/MMBtu}) + \textbf{\$100.00} = \boxed{\textbf{\$1,020.00}}$$

FIGURE 4-8. Valuation of unprocessed gas sold under an arm's-length contract with additional monies received under another agreement



Derrick Drilling sells gas at an off-lease location to Valley Pipeline under an arm's-length contract at a price of $1.60/Mcf. Derrick incurs a cost of $0.12/Mcf to transport the gas from the lease to the sales point.

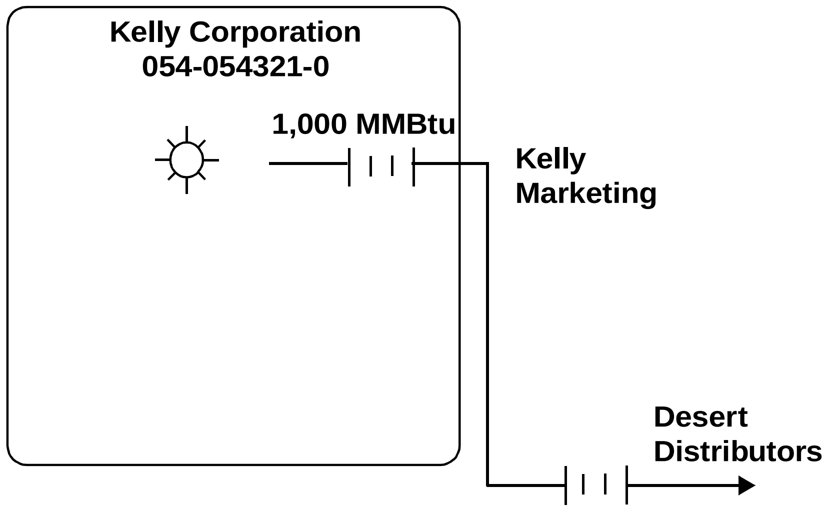
Value is based on gross proceeds.

Value: **100 Mcf** × **$1.50/Mcf** = **$150.00**

A transportation allowance may be deducted from the value.

Transportation allowance: **100 Mcf** × **$0.12/Mcf** = **$12.00**

FIGURE 4-9. Valuation of unprocessed gas sold under an arm's-length contract with transportation costs incurred prior to sale



Kelly Corporation transfers gas to Kelly Marketing at the wellhead.

Kelly Marketing transports and sells the gas to Desert Distributors under an arm's-length contract at a price of $2.05/MMBtu.

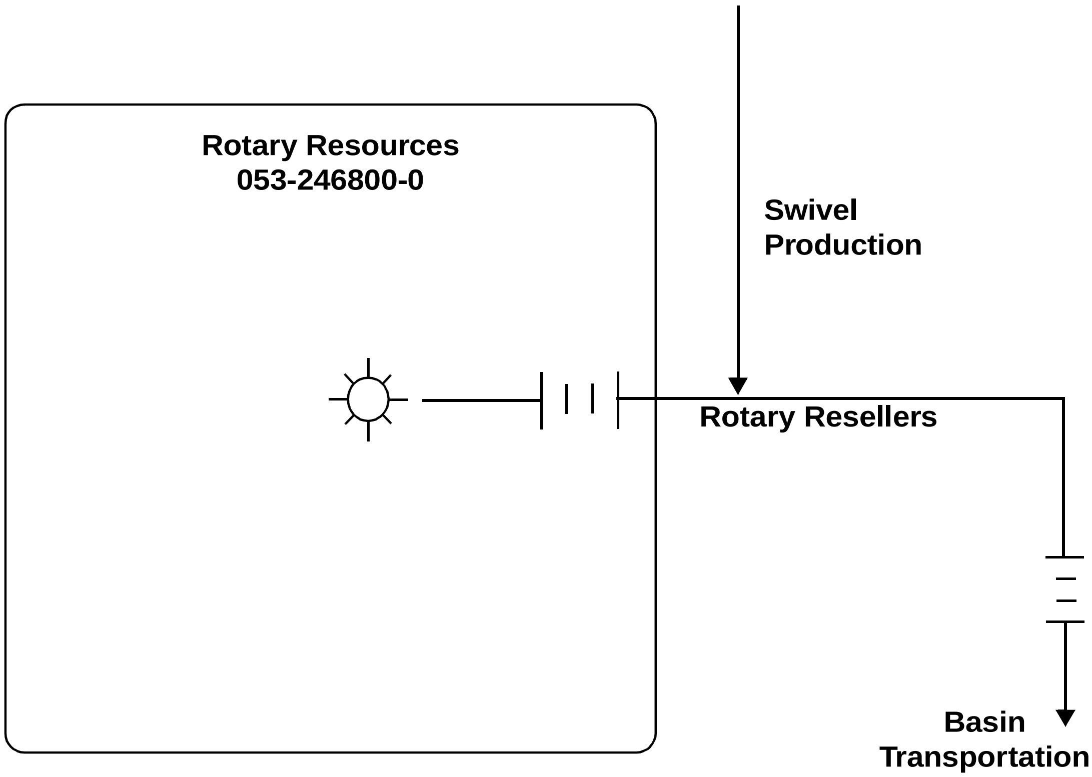
Kelly Marketing purchases only Kelly Corporation's gas and meets the definition of a marketing affiliate.

Value is based on the arm's-length sales price received by Kelly Marketing from Desert Distributors.

Value: **1,000 MMBtu × $2.05/MMBtu = $\boxed{\text{\$2,050.00}}$**

A transportation allowance may be deducted from the value for transportation from the lease to the sales point.

FIGURE 4-10. Valuation of unprocessed gas sold to a marketing affiliate



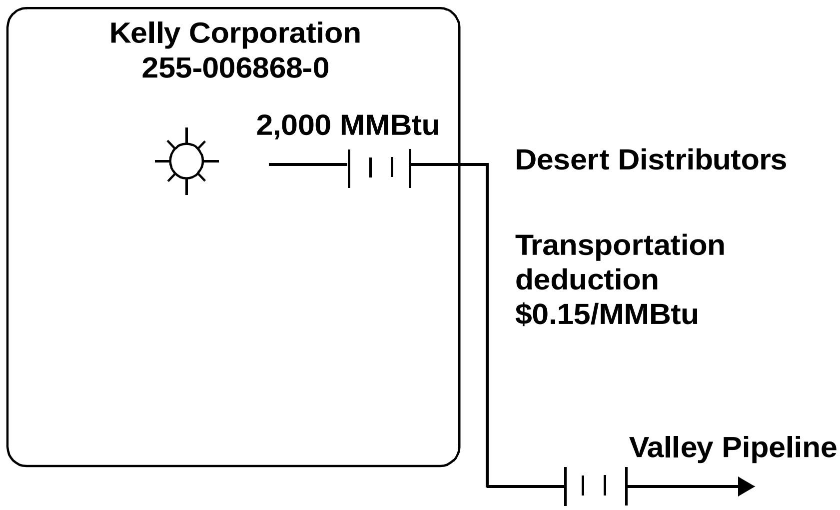
Rotary Resources transfers gas to Rotary Resellers at the wellhead.

Rotary Resellers transports and sells the gas to Basin Transportation under an arm's-length contract at a price of $1.85/MMBtu.

Rotary Resellers purchases gas from other producers and does not meet the definition of a marketing affiliate.

The value of Rotary Resources' gas is determined under the benchmark system (see "Valuation of unprocessed gas not sold under an arm's-length contract" on p. 4-20).

FIGURE 4-11. Valuation of unprocessed gas sold to an affiliate that is not a marketing affiliate



Kelly Corporation sells gas at the wellhead to Desert Distributors under an arm's-length contract at a price of $2.05/MMBtu, less a transportation deduction of $0.15/MMBtu.

The $0.15/MMBtu price deduction for transportation is considered a transportation factor.

Value is based on Kelly's gross proceeds, which are based on a net price of $1.90/MMBtu.

Value: **2,000 MMBtu × $1.90/MMBtu = $\boxed{\text{\$3,800.00}}$**

FIGURE 4-12. Valuation of unprocessed gas sold under an arm's-length contract where the price is reduced by a transportation factor

4.1.2 Valuation of unprocessed gas not sold under an arm's-length contract

Unprocessed gas that is not sold under an arm's-length contract is valued under the benchmark system (30 CFR 206.152(c) and 30 CFR 206.172(c)). The benchmark system governs the valuation of unprocessed gas under any of the following three conditions:

- The gas is sold under a non-arm's-length contract;
- The gas is transferred without a contract; or
- The gas is sold or disposed of under an arrangement that does not meet the criteria for valuation under an arm's-length contract.

The disposition of unprocessed gas under any of these conditions is referred to as non-arm's-length.

The benchmark system for valuing unprocessed gas under non-arm's-length conditions consists of three prioritized benchmarks. Value is based on the first benchmark that is applicable to the lessee's situation. If the first benchmark does not apply or cannot be used, the lessee must use the second benchmark to determine value. This process is continued through the third benchmark. Value can never be less than the gross proceeds accruing to the lessee for sales under a non-arm's-length contract (30 CFR 206.152(h) and 30 CFR 206.172(h)).

For all value determinations under the benchmark system, the lessee must retain all relevant data (30 CFR 206.152(e)(1) and 30 CFR 206.172(e)(1)).

4.1.2.1 First valuation benchmark: Lessee's gross proceeds if equivalent to gross proceeds under comparable arm's-length contracts

Under the first benchmark, the gross proceeds accruing to the lessee under its non-arm's-length contract are acceptable for royalty value, provided those gross proceeds are equivalent to the gross proceeds derived from, or paid under, comparable arm's-length contracts for sales, purchases, or other dispositions of like-quality gas from the same field (30 CFR 206.152(c)(1) and 30 CFR 206.172(c)(1)). If transactions for production from the same field do not provide a reasonable sample of arm's-length values, the surrounding area should be used.

Equivalency. The lessee's non-arm's-length gross proceeds are considered equivalent if they are not less than the gross proceeds derived from or paid under the most comparable arm's-length contract in the same field (or area) for like-quality gas.

Comparability. Use the following factors to evaluate comparability of arm's-length contracts:

- Price
- Duration of the contract
- Market(s) served
- Terms
- Quality of gas
- Volume
- Other appropriate factors

Lessees must use the most comparable arm's-length contract to determine value. For example, a 5-year sales contract for a large volume of unprocessed gas delivered to a distant utility company is not comparable to a monthly interruptible sales contract covering a small volume of unprocessed gas sold in the field.

Gross proceeds. The lessee's gross proceeds for unprocessed gas sold under a non-arm's-length contract include all consideration paid directly or indirectly under the contract, the same as under arm's-length contracts. However, the gross proceeds under a non-arm's-length contract cannot be reduced by a transportation factor (see "Transportation factors" on p. 4-12 for an explanation of a transportation factor). If the lessee's proceeds under its non-arm's-length contract are reduced by the costs of transportation, the transportation reduction must be added to those proceeds to determine value for royalty purposes. The lessee may, however, receive an allowance for its actual transportation costs.

4.1.2.2 Second valuation benchmark: Other relevant information

The second benchmark is used if the lessee's gross proceeds are not equivalent to the gross proceeds paid under comparable arm's-length contracts, or if no comparable arm's-length contracts exist in the field or area. The second benchmark is also applicable when the lessee receives no consideration for the disposition of its gas, as in cases of waste or avoidable loss. Under this benchmark, the lessee must consider other information that is relevant or would be used in valuing like-quality gas in the field or area (30 CFR 206.152(c)(2) and 30 CFR 206.172(c)(2)), including:

- The gross proceeds under arm's-length contracts in the field or area;
- Published prices for unprocessed gas;
- Prices for arm's-length spot sales of unprocessed gas;
- Other reliable public sources of price or market information; or
- Other information relevant to the particular lease operation or the salability of the lessee's gas.

The lessee must select the method that best determines the value of the lessee's unprocessed gas. The selected criterion should either:

- Reflect most closely the circumstances surrounding the disposition of the lessee's unprocessed gas, or
- Be the most relevant factor in valuing the lessee's unprocessed gas.

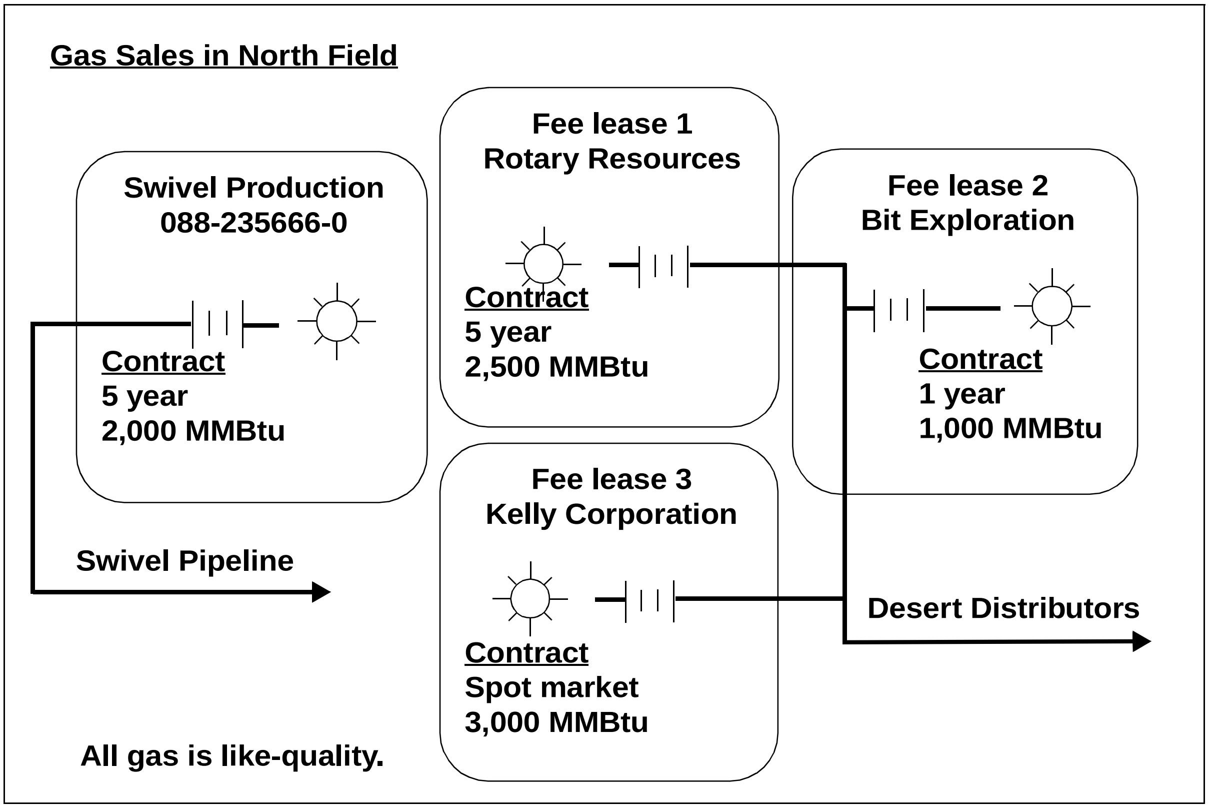
For example, if comparable arm's-length contracts exist in the field or area as required under the first benchmark, but the lessee's gross proceeds are less than the gross proceeds under those contracts, the gross proceeds under the most comparable arm's-length contracts would be used to establish value. If no arm's-length contracts exist in the field or area, published prices, adjusted for quality and transportation, may be the best determinant of value. Or, other factors, such as weighted-average prices, contractually reduced prices for transportation, or certain non-arm's-length contract prices may be used in establishing value.

Published prices and spot market prices for unprocessed gas may be obtained from natural gas periodicals such as *Natural Gas Intelligence, Natural Gas Week*, *Inside F.E.R.C.'s Gas Market Report*, and other similar publications.

4.1.2.3 Third valuation benchmark: Net-back or other reasonable valuation method

The third benchmark for valuing unprocessed gas is the net-back method or any other reasonable method for valuation (30 CFR 206.152(c)(3) and 30 CFR 206.172(c)(3)). This benchmark is used to determine value if there are no other factors relevant in valuing like-quality unprocessed gas in the field or area. Because the circumstances regarding the use of a net-back or other method cannot be foreseen, no instructions are provided in this handbook. The acceptability of such methods is determined solely on the merits of each method on a case-by-case basis.

Figures 4-13 through 4-20 illustrate valuation of unprocessed gas not sold under arm's-length contracts. Values reported on Form MMS-2014 are shown in boxes.



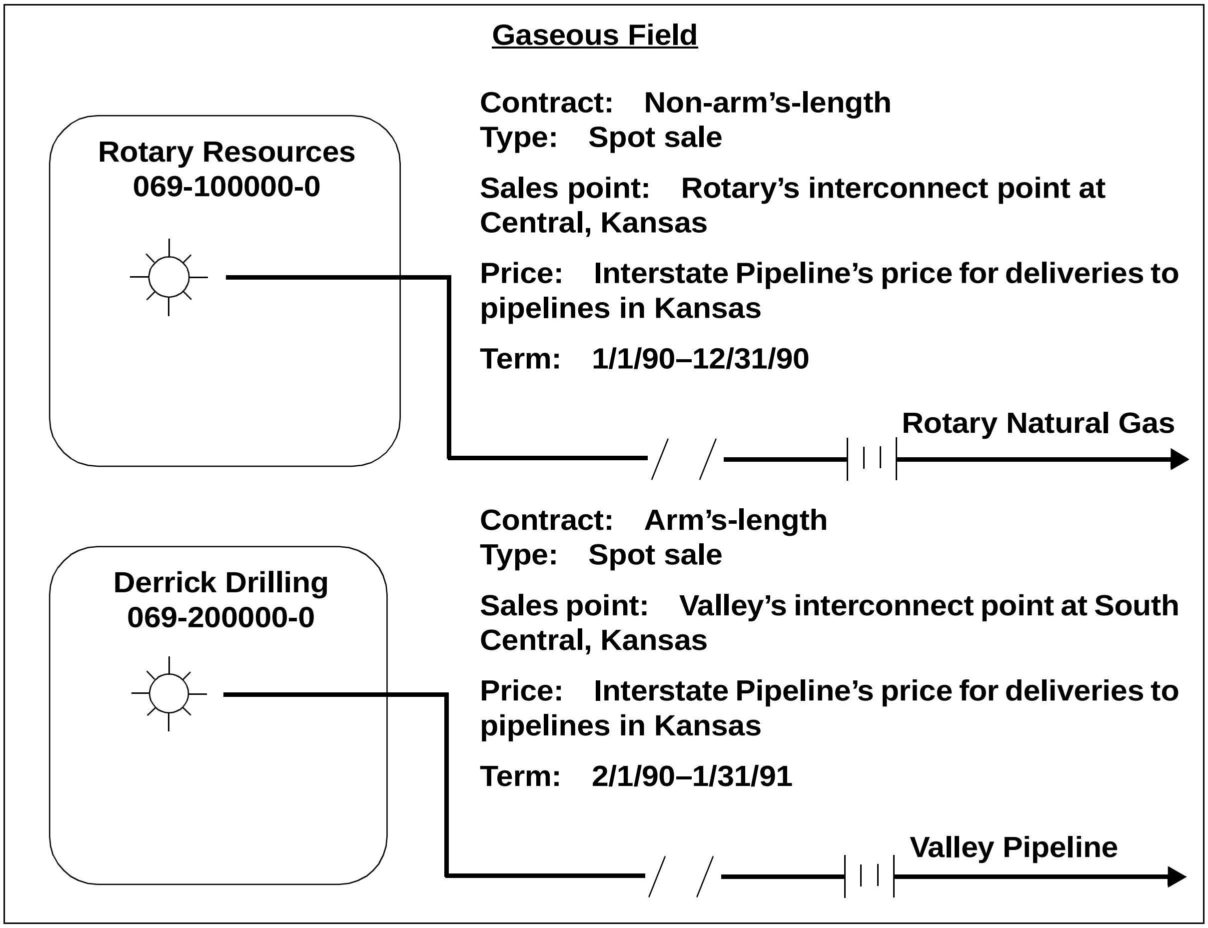
Producer	Contract type	Price ($/MMBtu)
Swivel Production	non-arm's-length	$1.75
Rotary Resources	arm's-length	1.70
Bit Exploration	arm's-length	1.80
Kelly Corporation	arm's-length	2.00

The most comparable contract is Rotary Resources' contract.

Swivel Production's price of $1.75/MMBtu is equivalent to the price paid under Rotary Resources' contract. Therefore, Swivel Production's gross proceeds based on $1.75/MMBtu is acceptable for value under benchmark 1.

Value: 2,000 MMBtu x $1.75/MMBtu = $\boxed{\$3{,}5000.00}$

FIGURE 4-13. Valuation of unprocessed gas under benchmark 1 where lessee's price is equivalent to prices paid under a comparable arm's-length contract



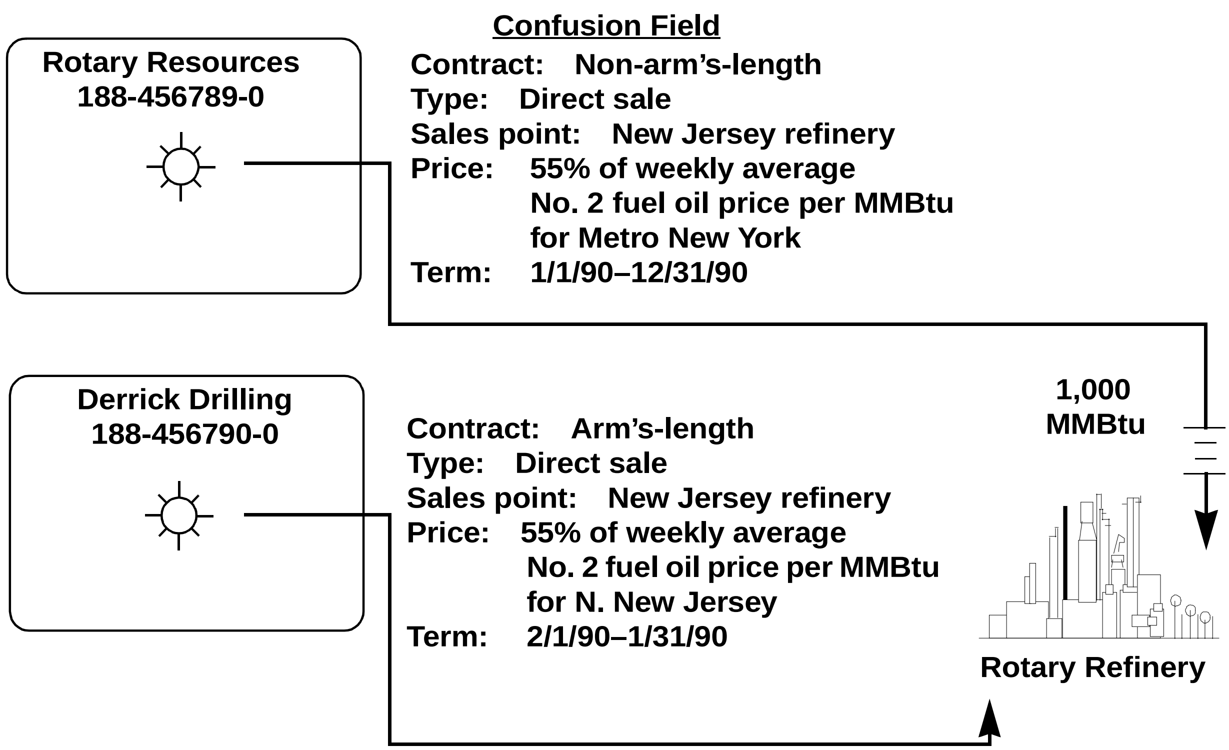
All gas is like-quality.

The most comparable contract is Derrick Drilling's contract.

Rotary Resources' price is equivalent to the price paid under Derrick Drilling's contract. Therefore, Rotary Resources' gross proceeds based on its non-arm's-length contract is acceptable for value for the period 2/1/90–12/31/90 under benchmark 1.

Rotary Resources may deduct a transportation allowance from the value for the costs of moving the gas to the sales point.

FIGURE 4-14. Valuation of unprocessed gas under benchmark 1 where lessee's contract is comparable to another arm's-length contract in the field



All gas is like-quality.

Rotary Refining purchases all gas from the field at its New Jersey refinery.

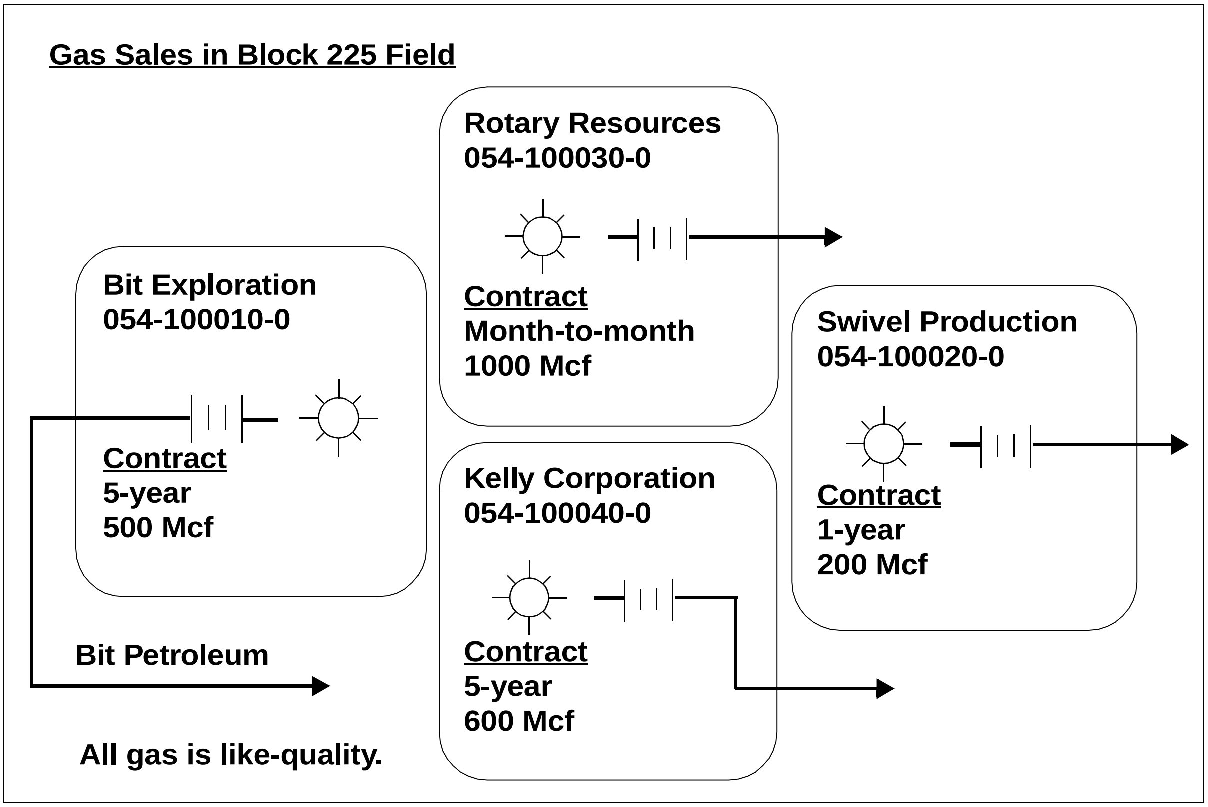
Fuel oil prices for Metro New York range from \$0.01/gal to \$0.02/gal higher than for N. New Jersey (for this example, \$0.65/gal = \$4.68/MMBtu).

The most comparable contract is Derrick Drilling's contract.

Rotary Resources' price under its non-arm's-length contract is equivalent to the price paid under Derrick Drilling's contract. Therefore, Rotary Resources' gross proceeds based on its non-arm's-length contract is acceptable for the period 2/1/90-12/31/90 under benchmark 1.

Value: 1,000 MMBtu x 55% x \$4.68/MMBtu = $\boxed{\$2,574.00}$

FIGURE 4-15. Valuation of unprocessed gas under benchmark 1 where lessee's contract meets both the comparability and equivalency criteria



Producer	Sales point	Contract type	Price ($/Mcf)
Bit Exploration	wellhead	non-arm's-length	$1.80
Rotary Resources	wellhead	arm's-length	2.10
Swivel Production	wellhead	arm's-length	1.90
Kelly Corporation	wellhead	arm's-length	2.20

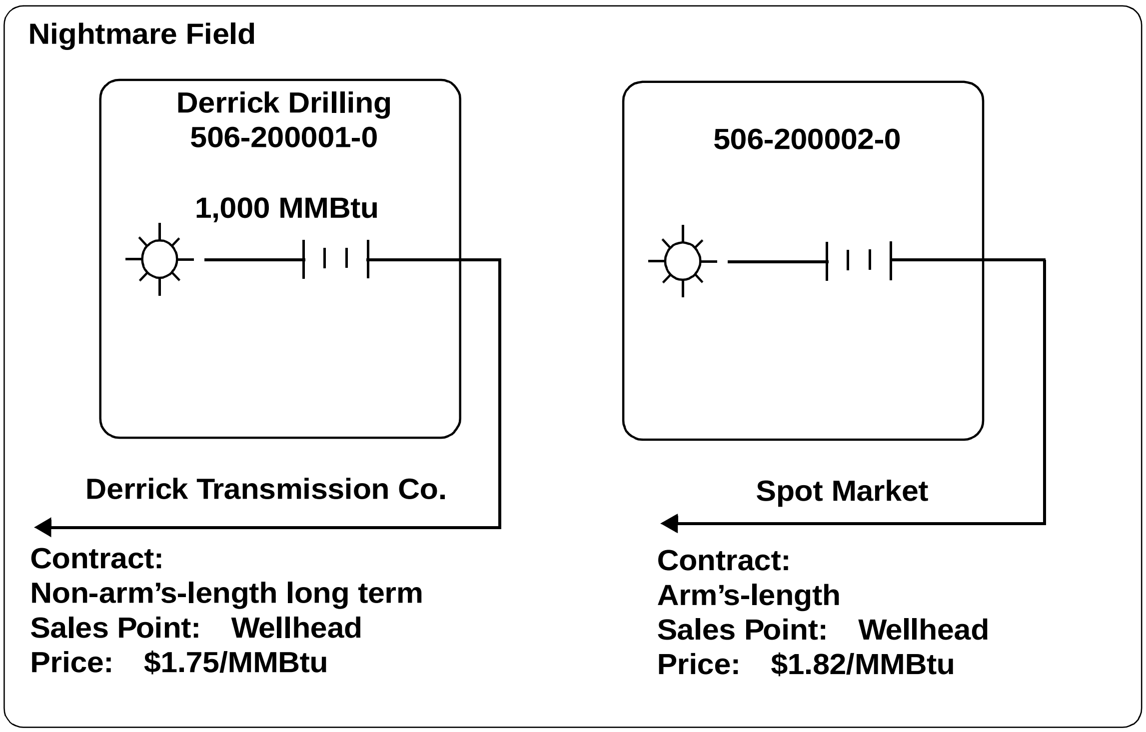
Bit Exploration's gross proceeds based on $1.80/Mcf are less than the gross proceeds under arm's-length contracts in the field.

The most comparable contract in the field is Kelly Corporation's contract.

Bit Exploration must use this contract to value its gas under benchmark 2.

Value: 500 Mcf x $2.20/Mcf = $\boxed{\$1,100.00}$

FIGURE 4-16. Valuation of unprocessed gas under benchmark 2 where lessee's price is not equivalent to prices under comparable arm's-length contracts



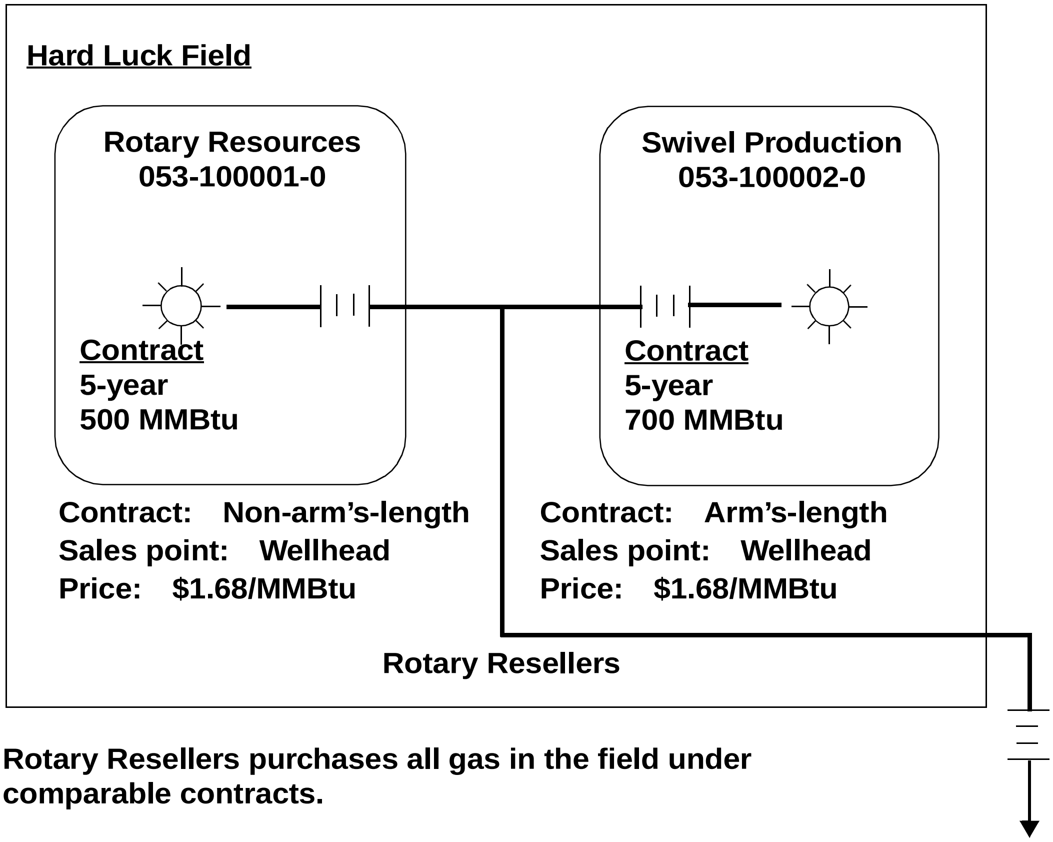
All gas is like-quality.

No comparable long-term arm's-length contracts exist in the area.

Derrick Drilling may value its gas from lease 056-200001-0 under benchmark 2 based on the arm's-length spot market price of $1.82/MMBtu.

Value: **1,000 MMBtu** × **$1.82/MMBtu** = **$1,820.00**

FIGURE 4-17. Valuation of unprocessed gas under benchmark 2 where no comparable arm's-length contract exists in the field



Rotary Resellers purchases all gas in the field under comparable contracts.

All gas is like-quality.

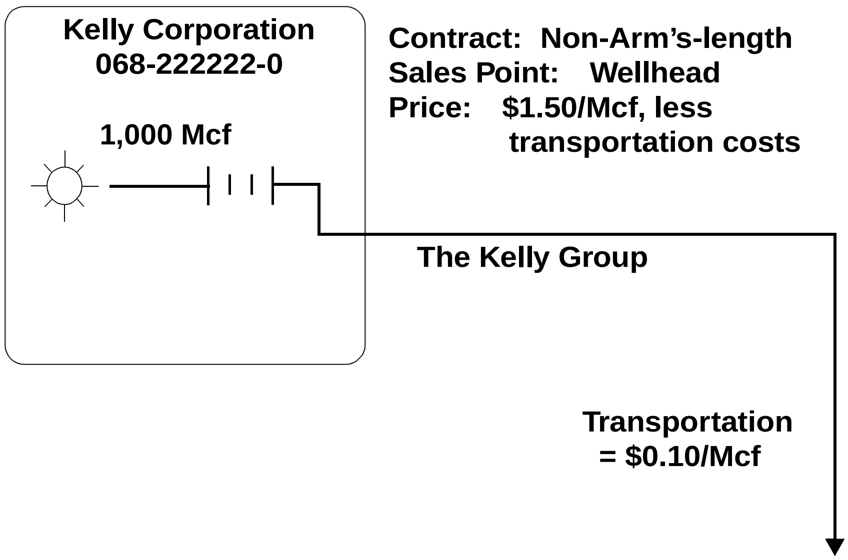
Rotary Resellers purchases gas from other producers and therefore does not meet the definition of a marketing affiliate. Thus, the value of Rotary Resources' gas must be determined under the benchmark system.

The most comparable contract is Swivel Production's contract.

Rotary Resources' gross proceeds are equivalent to the gross proceeds paid under Swivel Production's Contract. Therefore, Rotary Resources' gross proceeds are acceptable in valuing Rotary Resources' gas under benchmark 1.

Value: 500 MMBtu x $1.68/MMBtu = $\boxed{\$840.00}$

FIGURE 4-18. Valuation of unprocessed gas under benchmark 1 where the gas is sold to an affiliate who is not a marketing affiliate



Kelly Corporation's revenues under its non-arm's-length contract are:

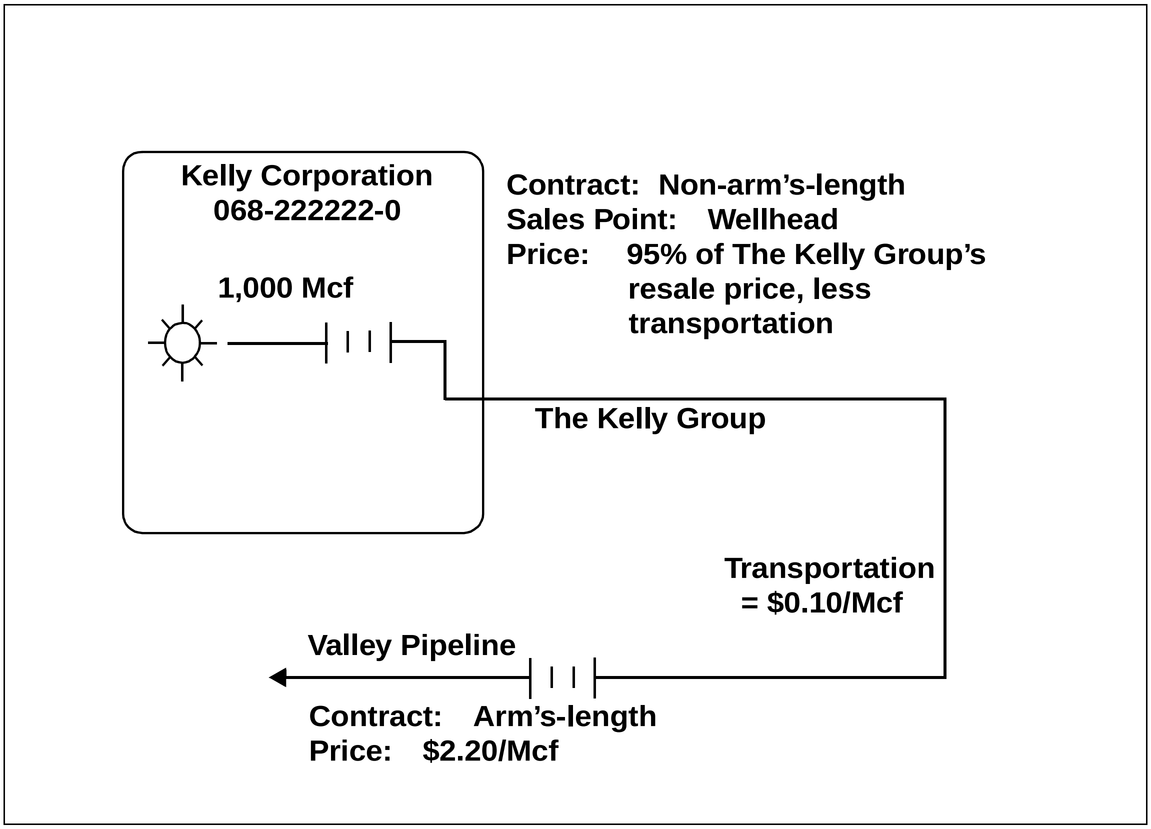
$$(\textbf{1,000 Mcf} \times \textbf{\$1.50/Mcf}) - (\textbf{1,000 Mcf} \times \textbf{\$0.10/Mcf}) = \textbf{\$1,400.00}$$

However, the transportation deduction in the non-arm's-length contract is not allowed in determining gross proceeds for valuation under the benchmarks.

Kelly Corporation must report gross proceeds under the benchmark system as follows: $\textbf{1,000 Mcf} \times \textbf{\$1.50/Mcf} = \boxed{\textbf{\$1,500.00}}$

Kelly Corporation may claim actual transportation costs under its non-arm's-length contract as a separate transportation allowance (Ch. 5, "Oil Transportation Allowances").

FIGURE 4-19. Valuation of unprocessed gas under benchmark 1 where the non-arm's-length gross proceeds cannot be reduced by a transportation factor



The Kelly Group is not a marketing affiliate.

No sales of like-quality gas under comparable arm's-length contracts exist in the field or area.

Therefore, valuation falls under benchmark 2. The Kelly Group's full resale value may be the best indicator of value.

Value: 1,000 Mcf $\times$ \$2.20/Mcf = $\boxed{\$2{,}200.00}$

Kelly Corporation may claim actual transportation costs under its non-arm's-length contract as a separate transportation allowance (Ch. 5, "Oil Transportation Allowances").

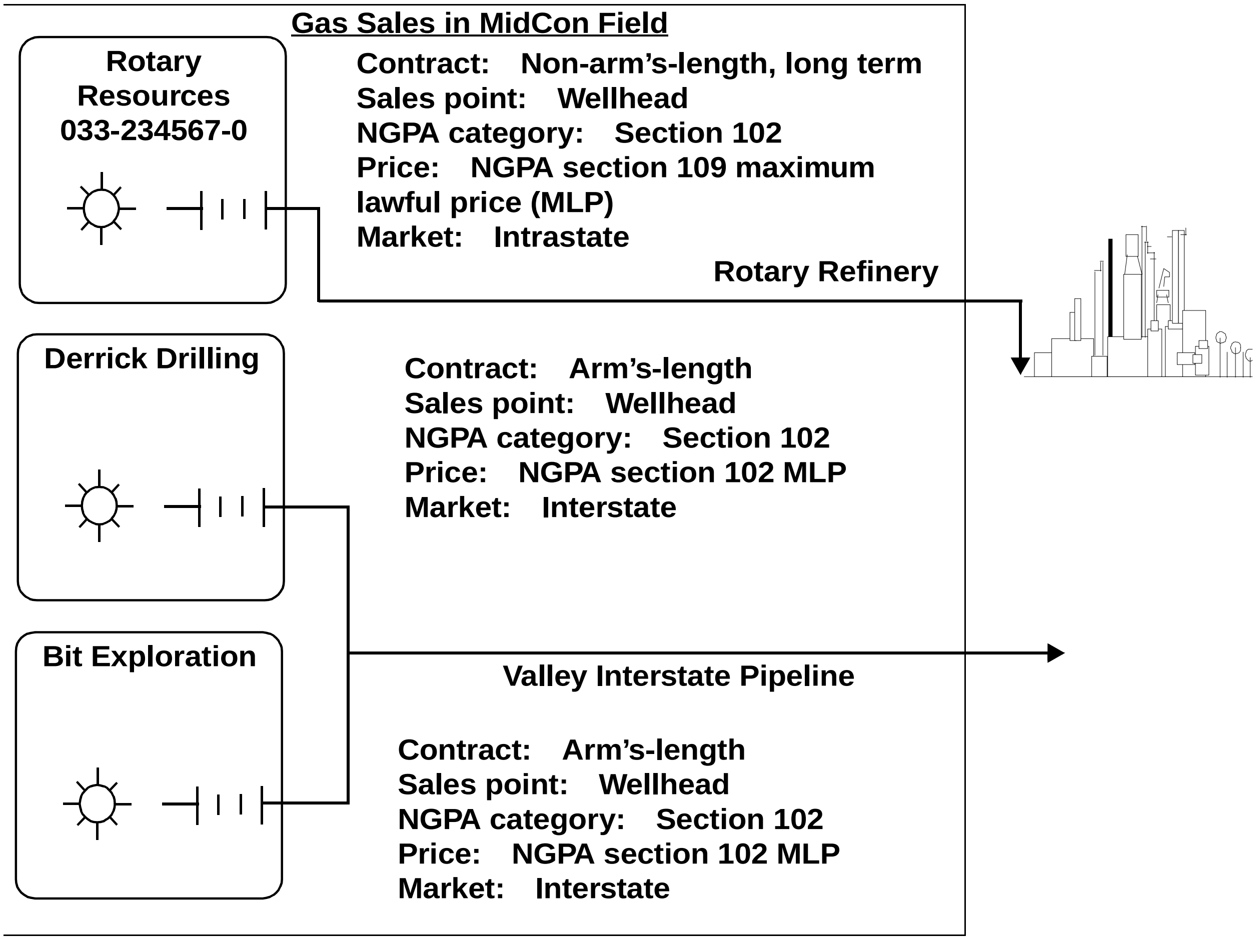
FIGURE 4-20. Valuation of unprocessed gas under benchmark 2 where no comparable arm's-length contract exists and the affiliate resells the gas

4.1.3 Effects of regulated prices

The value of the lessee's unprocessed gas cannot be greater than the maximum price permitted by Federal law (30 CFR 206.152(d)(1) 30 CFR 206.172(d)(1)). The maximum price permitted by Federal law includes consideration paid under section 110 of the NGPA.

Price limitations set by State or local governments that do not exceed Federal price limitations, although permissible under the NGPA section 602 for intrastate sales of gas, are not considered as having the effect of a maximum price prescribed by Federal law and do not limit any values determined under this chapter. Furthermore, the limitations on value because of Federal price controls do not apply in valuing gas sold under a warranty contract (30 CFR 206.152(d)(2) and 30 CFR 206.172(d)(2)). (See "Warranty contracts" on page 4-68.)

Figure 4-21 illustrates the effects of regulated prices on the value of unprocessed gas.



The State regulatory ceiling price for NGPA section 102 intrastate gas is the NGPA section 109 MLP.

No comparable arm's-length contracts exist in the field or area.

Benchmark 2 must be used for valuation.

Value is based on prices under arm's-length contracts for section 102 gas in the field (NGPA section 102 MLP for interstate sales).

The price for royalty purposes is not limited by the State ceiling price, which is the NGPA section 109 price.

FIGURE 4-21. Effect of State-regulated price on value where arm's-length contracts for like-quality gas exist in the field

4.2 Processed Gas

Gas that has been processed by the lessee or its affiliate in a gas processing plant for the recovery of individual components contained in the raw gas stream is valued as processed gas. Processed gas consists of residue gas and gas plant products. Residue gas contains primarily methane plus small amounts of other gases, liquids, or impurities. Gas plant products are any liquid, gaseous, or solid substances that are recovered from the gas stream in marketable condition in addition to the residue gas. Gas plant products include ethane, propane, butane, and other liquefiable hydrocarbons, collectively referred to as NGLs; carbon dioxide; nitrogen; and sulfur. All NGLs recovered at a processing plant are considered a single gas plant product for MMS reporting purposes.

Any one of the following criteria determines when Federal gas is valued as processed gas (30 CFR 206.152 and 30 CFR 206.153):

- The lessee, or the lessee's affiliate to whom the lessee has sold or transferred the gas under a non-arm's-length contract, processes the gas. This includes those situations where the lessee reserves and then exercises the right to process the gas under a contract for the sale of gas prior to processing.

- The gas is produced prior to November 1, 1991, and the lessee sells the gas under either an arm's-length or a non-arm's-length POP contract.

- The gas is produced on or after November 1, 1991, and the lessee sells the gas under a **non-arm's-length** POP contract.

- The gas is not covered by the provisions of 30 CFR 206.152 or 30 CFR 206.172 governing the valuation of unprocessed gas.

Gas produced from Indian leases is valued as processed gas under any of these conditions and in certain accounting for comparison (dual accounting) situations. That is, if the gas is physically processed and the lease terms require dual accounting, the gas is valued as processed gas if that value is greater than the value of the gas prior to processing (30 CFR 206.175(a) and (b)). (See "Accounting for Comparison" on page 4-90 for details regarding dual accounting.)

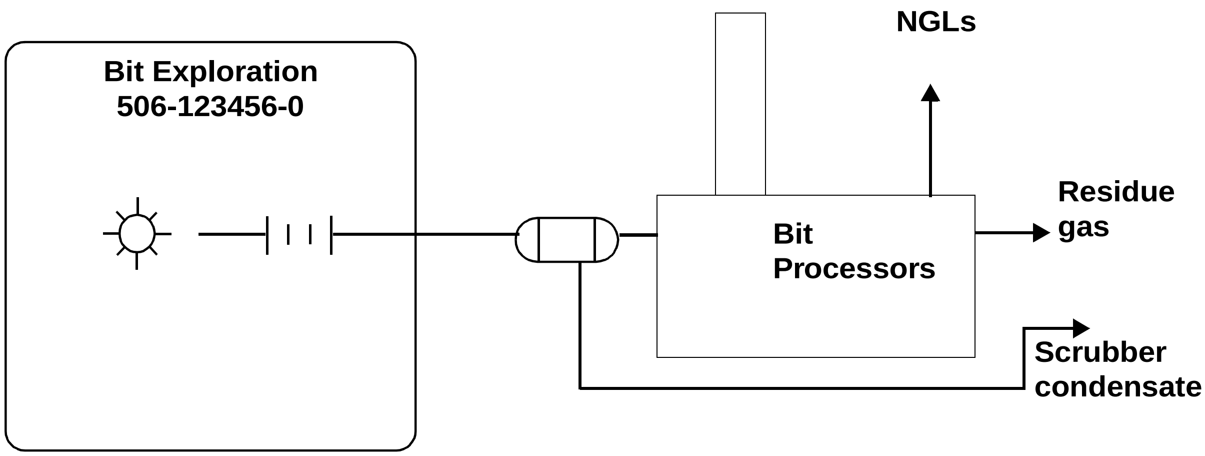
The value of processed gas is determined on the basis of the full value of residue gas, gas plant products, and drip condensate recovered downstream from the point of royalty settlement without resorting to processing, less allowances. A processing allowance may be deducted from the value of each individual gas plant product for the costs of extracting that product from the gas stream. Also, a transportation allowance may be deducted for the costs of transporting, if applicable, residue gas, gas plant products, or drip condensate to the plant and/or to a sales point away from the plant (30 CFR 206.153(a)(2) and 30 CFR 206.173(a)(2)). (See chapters 5, 6, and 7 for the determination of transportation and processing allowances.)

The method for determining the value of residue gas and gas plant products is based on whether or not the residue gas or gas plant products are sold under an arm's-length contract. As is the case with unprocessed gas, the price established by the arm's-length contract is generally acceptable for value. For sales or dispositions not involving an arm's-length contract, the value is determined under a benchmark system. All reported values are subject to monitoring, review, and audit.

For gas sold under a POP contract and valued as processed gas, the value of the residue gas and gas plant products is determined as if the person actually disposing of the residue gas and gas plant products were the Federal or Indian lessee. That is, the disposition of the residue gas or gas plant products by the purchaser/processor (such as under an arm's-length or non-arm's-length contract) determines the valuation criteria for the residue gas or gas plant products. (See "POP contracts" on p. 4-56 for further information regarding valuation under POP contracts.)

Condensate recovered from the gas stream without resorting to processing is valued as oil (see chapter 3).

Figures 4-22 through 4-26 illustrate when gas is valued as processed gas.

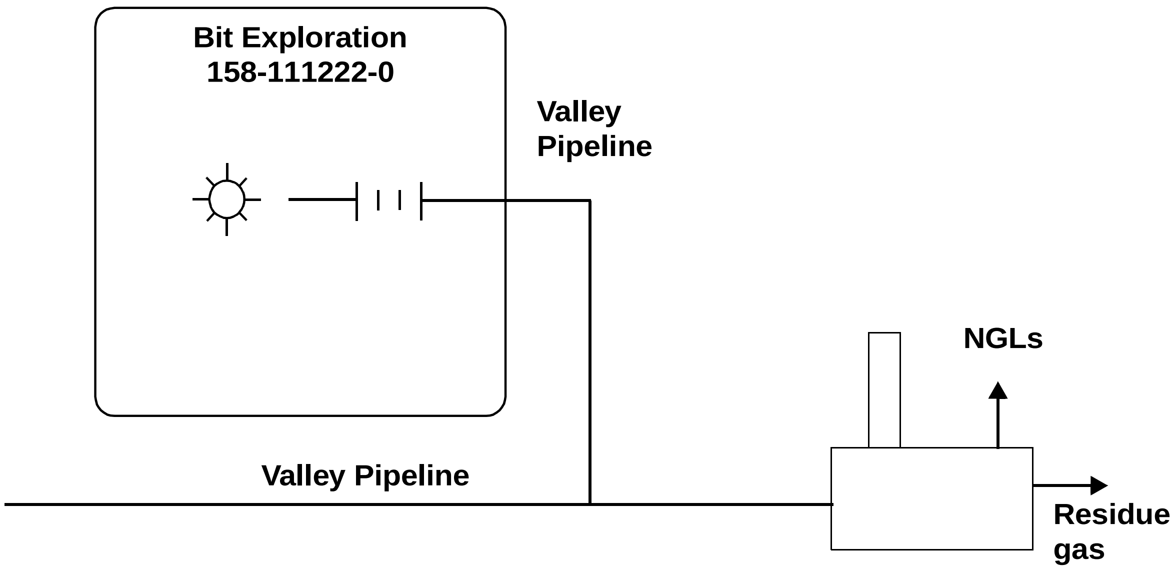


Bit Exploration sells gas to Bit Processors at the wellhead under a non-arm's-length contract.

The gas is valued as processed gas.

Value is based on 100 percent of values of residue gas, NGLs, and scrubber condensate, less a processing allowance (and a transportation allowance, if applicable). However, value may be no less than the gross proceeds accruing to Bit Exploration under its non-arm's-length contract.

FIGURE 4-22. Gas valued as processed: Non-arm's-length sales contract prior to processing

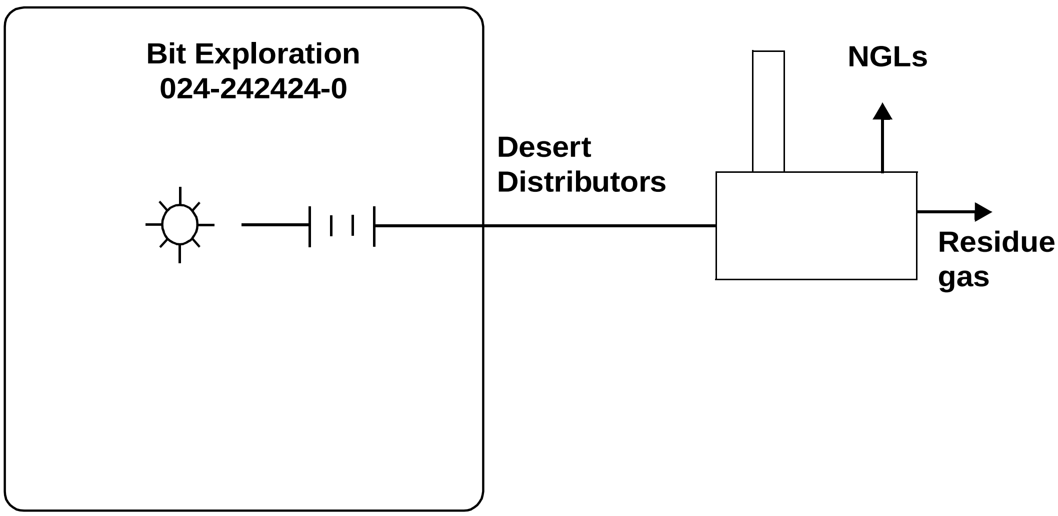


Bit Exploration sells gas to Valley Pipeline at the wellhead under an arm's-length contract. However, Bit reserves and exercises the rights to extract NGLs.

The gas is valued as processed gas.

Value is based on 100 percent of the values of residue gas and NGLs less a processing allowance (and a transportation allowance, if applicable).

FIGURE 4-23. Gas valued as processed: Arm's-length wellhead sales contract where the lessee reserves and exercises the processing rights



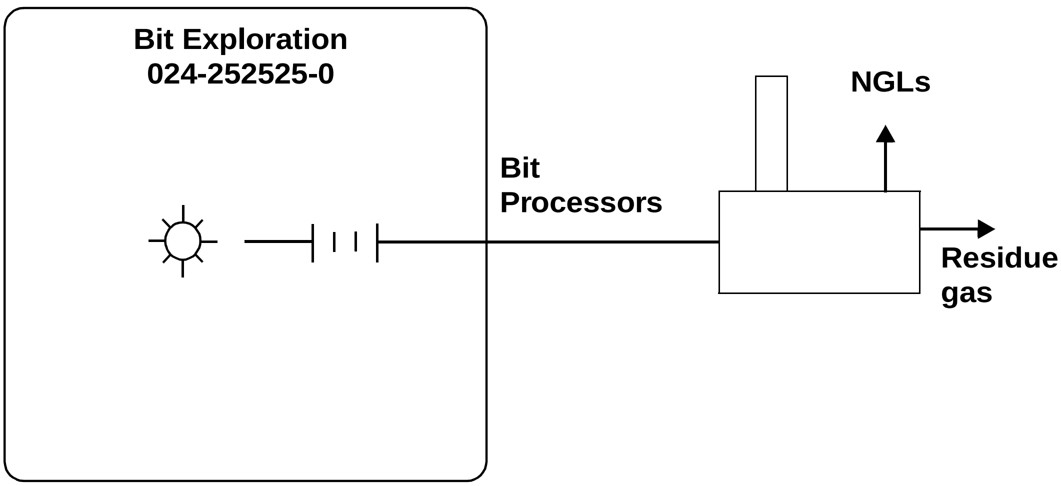
Bit Exploration sells gas to Desert Distributors under an arm's-length POP contract.

The gas produced before November 1, 1991, is valued as processed gas. Value is based on 100 percent of the values of residue gas and NGLs, less a processing allowance (and a transportation allowance, if applicable).

The gas produced on and after November 1, 1991, is valued as unprocessed gas.

See "POP contracts" on page 4-56 for valuation under POP contracts.

FIGURE 4-24. Gas valued as processed or unprocessed: Arm's-length POP contract for production both before, and on and after, November 1, 1991

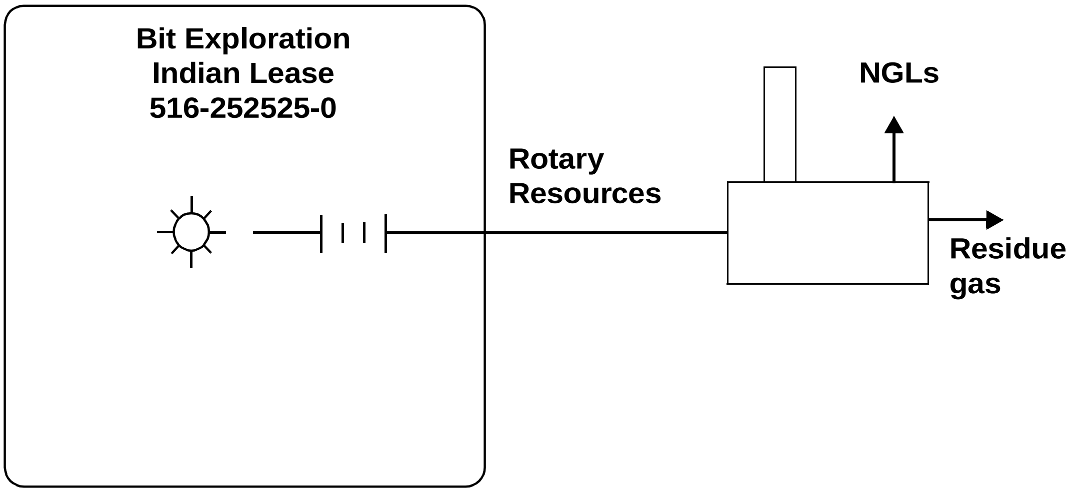


Bit Exploration sells gas to Bit Processors under a non-arm’s-length POP contract.

Gas is valued as processed gas.

Value is based on 100 percent of values of residue gas and NGLs, less a processing allowance (and a tranportation allowance, if applicable).

FIGURE 4-25. Gas valued as processed: Non-arm’s-length POP contract



Bit Exploration sells gas to Rotary Resources at the wellhead under an arm's-length contract. The gas is processed.

The Indian lease terms require dual accounting.

The value of 100 percent of the residue gas and NGLs, less a processing allowance (and a transportation allowance, if applicable) is greater than the unprocessed gas value.

Accordingly, the gas is valued as processed gas.

Note that if the value of the processed gas was less than the value of the unprocessed gas, value would be based on the unprocessed gas value.

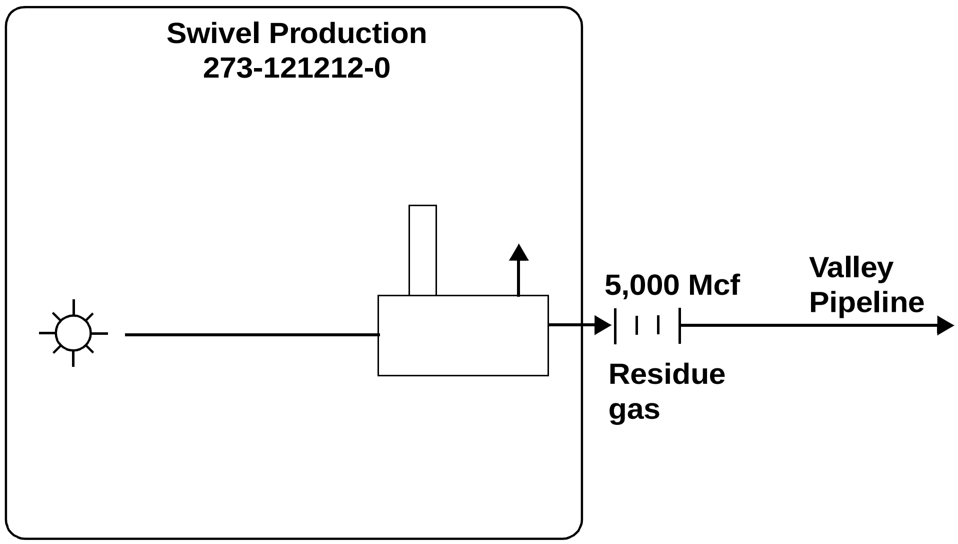
FIGURE 4-26. Indian gas valued as processed under dual accounting requirement

4.2.1 Valuation of processed gas sold under an arm's-length contract

The value of residue gas or gas plant products sold under an arm's-length contract is generally based on the gross proceeds accruing to the lessee under the provisions of the contract (30 CFR 206.153(b)(1)(i) and 30 CFR 206.173(b)(1)(i)). The criteria for accepting the arm's-length gross proceeds to value residue gas and gas plant products are the same criteria as those listed previously for unprocessed gas (see "Valuation of unprocessed gas sold under an arm's-length contract" on p. 4-9). Any payments or reimbursements made to the lessee for placing the residue gas or gas plant products in marketable condition, such as boosting residue gas or storing NGLs prior to sale, are considered part of the lessee's gross proceeds. Reimbursements under FERC Order No. 94 are also considered part of the lessee's gross proceeds.

Other factors in valuing residue gas or gas plant products sold under arm's-length contracts, such as total consideration, lessee misconduct, marketing affiliates, and transportation factors, are also the same as those for unprocessed gas. (See "Valuation of unprocessed gas sold under an arm's-length contract" on p. 4-9 for a discussion of these factors, and substitute the words "residue gas or gas plant products" in place of "unprocessed gas" for applicability to processed gas valuation.)

Figures 4-27 through 4-31 illustrate valuation of processed gas sold under arm's-length contracts. Values and allowances reported on Form MMS-2014 are shown in boxes.

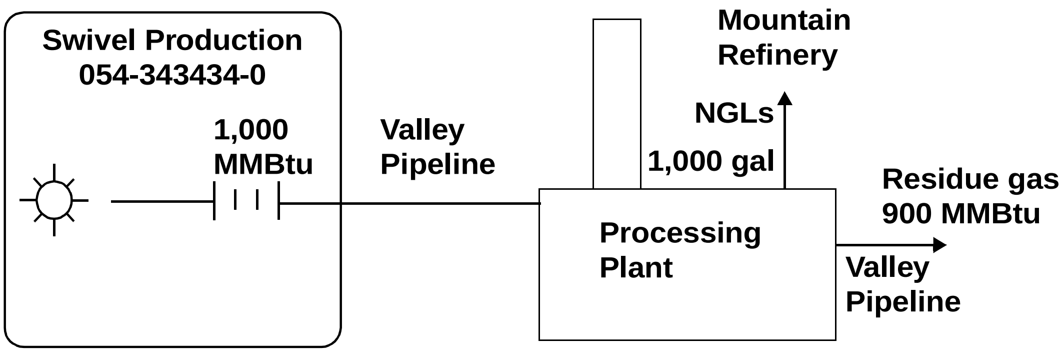


Swivel Production sells residue gas at the plant tailgate to Valley Pipeline under an arm's-length contract at a price of $2.53/Mcf.

Value of residue gas is based on gross proceeds.

Value: **5,000 Mcf** $\times$ **$2.53/Mcf** = $\boxed{\textbf{\$12,650.00}}$

FIGURE 4-27. Valuation of residue gas sold under an arm's-length contract



Swivel Production sells gas at the offshore lease to Valley Pipeline under an arm's-length contract at a price of $1.95/MMBtu. However, Swivel retains the rights to process and redelivers residue gas to Valley at the plant tailgate. Swivel then sells the NGLs to Mountain Refinery under an arm's-length contract at a price of $0.31/gal.

Plant volume reduction (PVR) attributable to Swivel's lease is 100 MMBtu.

The quantity of residue gas purchased by Valley attributable to Swivel's lease is the wellhead MMBtus minus the attributable PVR MMBtus.

Residue gas value is based on the gross proceeds.

Residue gas value: $\quad$ **$1.95/MMBtu × 900 MMBtu = $\boxed{\$1{,}755.00}$**

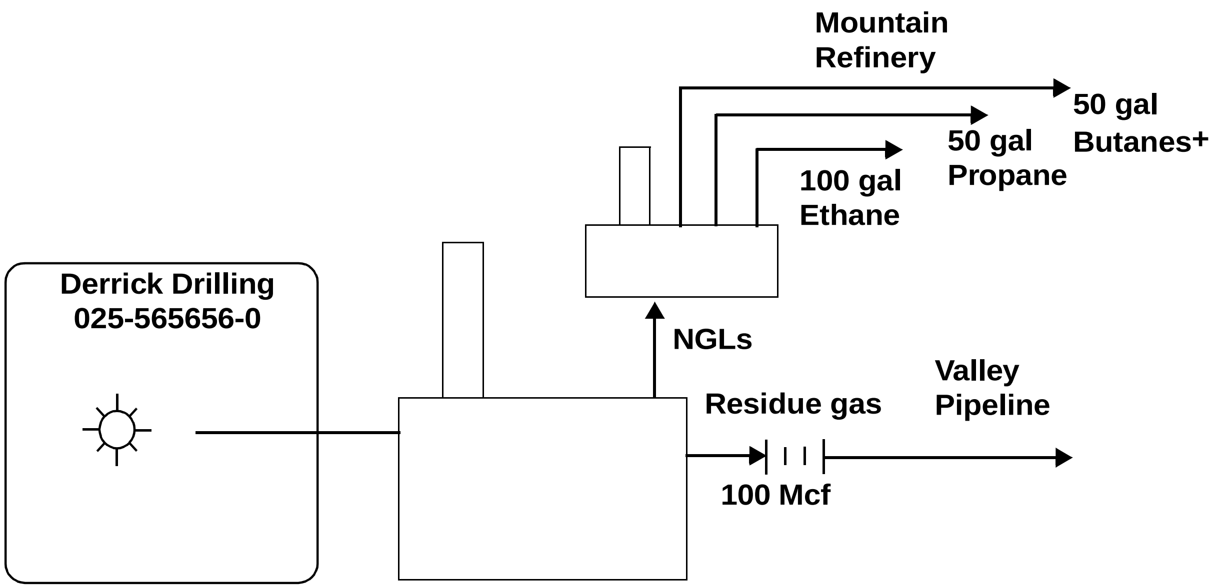
NGLs value is based on the gross proceeds paid for the NGL mix.

NGLs value: $\quad$ **1,000 gal × $0.31/gal = $\boxed{\$310.00}$**

A processing allowance may be deducted for the costs of extracting Swivel's NGLs (see Ch. 7, "Gas Processing Allowances").

Swivel may also claim a transportation allowance for the costs of transporting NGLs (as PVR) to the processing plant (see Ch. 6, "Gas Transportation Allowances").

FIGURE 4-28. Valuation of residue gas and NGLs sold under arm's-length contracts where lessee delivers gas at lease and reserves processing rights



Derrick Drilling processes its gas and sells the residue gas to Valley Pipeline under an arm's-length contract at a price of $1.50/Mcf. Derrick sells its fractionated NGLs to Mountain Refinery under an arm's-length contract at the following prices:

Ethane: $0.30/gal
Propane: $0.60/gal
Butanes+: $0.60/gal

Residue value is based on the gross proceeds.

Residue gas value: **100 Mcf** × **$1.50/Mcf** = $\boxed{\textbf{\$150.00}}$

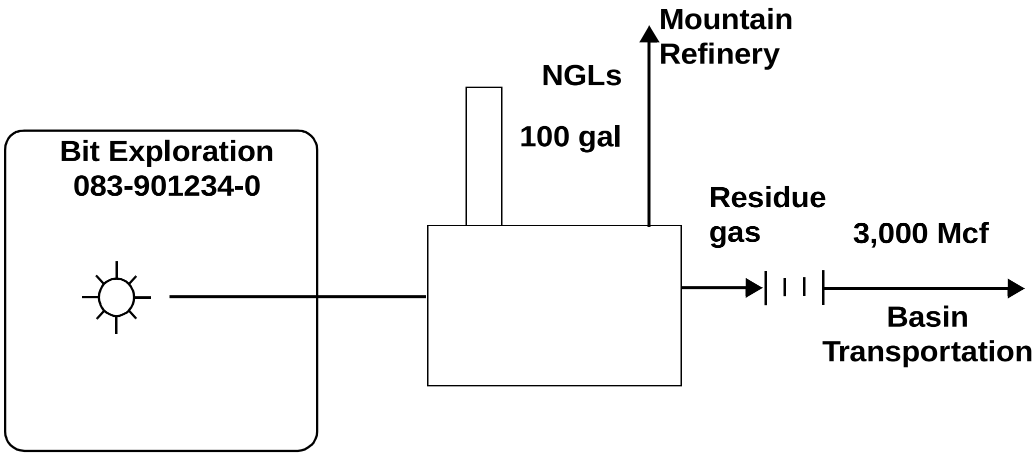
NGLs value is based on the gross proceeds.

NGLs value:

(**100 gal** × **$0.30/gal**) + (**50 gal** × **$0.60/gal**) + (**50 gal** × **$0.60/gal**) = $\boxed{\textbf{\$90.00}}$

Derrick may claim a processing allowance (see Ch. 7, "Gas Processing Allowances").

FIGURE 4-29. Valuation of residue gas and NGLs sold under arm's-length contracts where NGLs are sold individually



Bit Exploration processes its gas and sells the residue gas to Basin Transportation under an arm's-length contract at a price of $1.50/Mcf. The contract also provides for a $0.10/Mcf compression fee to meet pipeline pressure. Bit sells the NGL mix to Mountain Refinery under an arm's-length contract at a price of $0.40/gal. Bit also pays $0.05/gal to a third party for NGL storage.

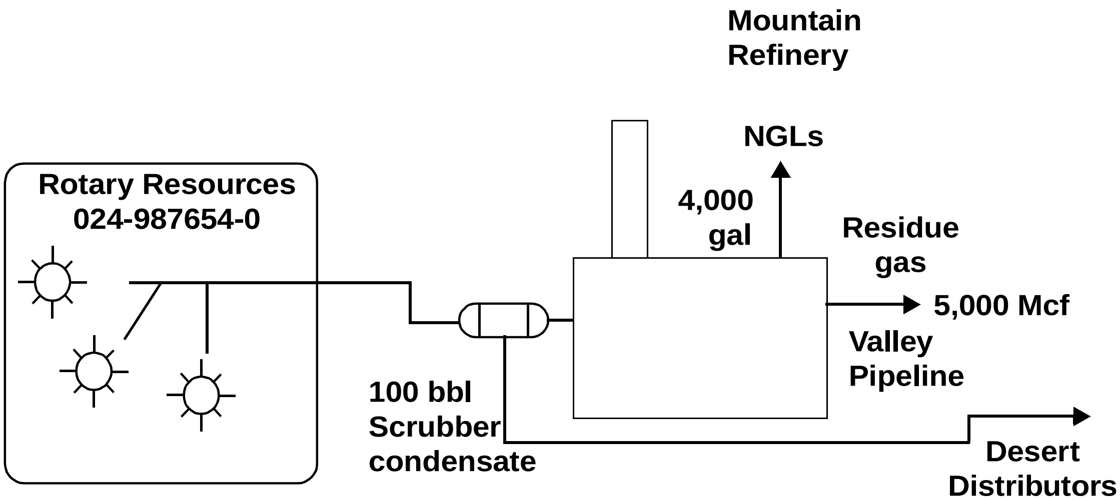
Value is based on the gross proceeds. However, the gross proceeds may not be reduced for the costs of placing the lease production in marketable condition.

Therefore, the price reduction for compression and the payment for NGL storage are not allowable deductions.

Residue gas value: $1.50/Mcf × 3,000 Mcf = **$4,500.00**

NGLs value: 100 gal × $0.40/gal = **$40.00**

FIGURE 4-30. Valuation of residue gas and NGLs sold under arm's-length contracts where prices are reduced for costs of services



Rotary Resources processes its gas and sells the residue gas to Valley Pipeline under an arm's-length contract at a price of $1.98/Mcf.

Rotary sells its NGLs to Mountain Refinery under an arm's-length contract at a price of $0.37/gal.

Rotary sells its condensate to Desert Distributors under an arm's-length contract at a price of $18.00/bbl.

Rotary has a processing allowance of $0.15/gal.

Value is based on gross proceeds less processing allowance.

Residue gas value: 5,000 Mcf × $1.98/Mcf = **$9,900.00**

NGLs value: 4,000 gal × 0.37/gal = **$1,480.00**

Condensate value: 100 bbl × $18.00/bbl = **$1,800.00**

Processing allowance: 4,000 gal × $0.15/gal = **$600.00**

FIGURE 4-31. Valuation of residue gas, NGLs, and scrubber condensate sold under arm's-length contracts

4.2.2 Valuation of processed gas not sold under an arm's-length contract

Residue gas or gas plant products that are not sold under an arm's-length contract are valued under the benchmark system (30 CFR 206.153(c) and 30 CFR 206.173(c)). The benchmark system governs the valuation of residue gas or gas plant products under any of the following three conditions:

- The residue gas or gas plant products are sold under a non-arm's-length contract.
- The residue gas or gas plant products are transferred without a contract.
- The residue gas or gas plant products are sold or disposed of under an arrangement that does not meet the criteria for valuation under an arm's-length contract.

The disposition of residue gas or gas plant products under any of these conditions is referred to as non-arm's-length.

The benchmark system for valuing residue gas or gas plant products is similar to the benchmark system for unprocessed gas (see "Valuation of unprocessed gas not sold under an arm's-length contract" on p. 4-20). However, like-quality residue gas or gas plant products from the same plant or nearby plants are considered rather than residue gas or gas plant products produced from the field or area. As with unprocessed gas, the lessee employs the first benchmark that is applicable to its situation. Also, the lessee must retain all relevant data used in the benchmark valuation. For sales of residue gas and gas plant products under a non-arm's-length contract, value can never be less than the gross proceeds accruing to the lessee under that contract (30 CFR §§ 206.153(h) and 206.173(h)).

4.2.2.1 First valuation benchmark: Lessee's gross proceeds if equivalent to gross proceeds under comparable arm's-length contracts for gas processed at the same plant

Under the first benchmark, the gross proceeds accruing to the lessee under its non-arm's-length contract are acceptable for royalty value, provided those gross proceeds are equivalent to the gross proceeds derived from, or paid under, comparable arm's-length contracts for sales, purchases, or other dispositions of like-quality residue gas or gas plant products from the same plant (30 CFR §§ 206.153(c)(1) and 206.173(c)(1)). If transactions for production from the same plant do not provide a reasonable sample of arm's-length values, nearby plants should be used.

Equivalency. The lessee's non-arm's-length gross proceeds are considered equivalent if they are not less than the gross proceeds derived from, or paid under, the most comparable arm's-length contract.

Comparability. Use the following factors to evaluate comparability of arm's-length contracts:

- Price
- Duration of contract
- Market(s) served
- Terms
- Quality of gas
- Volume
- Other appropriate factors

Lessees must use the most comparable arm's-length contract to determine value. For example, a 10-year contract to supply raw make to a nearby fractionation plant is not comparable to a monthly sales contract to sell raw make on the spot market.

Gross Proceeds. The lessee's gross proceeds for residue gas or gas plant products sold under a non-arm's-length contract include all consideration paid directly or indirectly under the contract, the same as under arm's-length contracts. However, the gross proceeds under a non-arm's-length contract cannot be reduced by a transportation factor (see "First valuation benchmark: Lessee's gross proceeds if equivalent to gross proceeds under comparable arm's-length contracts" on p. 4-20). If the lessee's proceeds under its non-arm's-length contract are reduced by the costs of transportation, the transportation reduction must be added to those proceeds to determine the value for royalty purposes. The lessee may, however, receive an allowance for its actual transportation costs.

4.2.2.2 Second valuation benchmark: Other relevant information

The second valuation benchmark is used if the lessee's gross proceeds are not equivalent to the gross proceeds paid under comparable arm's-length contracts for the plant or nearby plants or if no comparable arm's-length contracts exist for the plant or nearby plants. The second benchmark is also applicable when the lessee receives no consideration for the disposition of its gas as in cases of waste or unavoidable loss.

Under this benchmark, the lessee must consider other information that is relevant or would be used in valuing like-quality residue gas and gas plant products from the same or nearby gas plants (30 CFR 206.153(c)(2) and 30 CFR 206.173(c)(2)), including:

- The gross proceeds under arm's-length contracts at the plant or nearby plants;
- Published prices for residue gas or gas plant products;
- Prices under arm's-length spot sales of residue gas or gas plant products;
- Other reliable public sources of price or market information; and
- Other information relevant to the particular lease operation or the salability of the lessee's residue gas or gas plant products.

The lessee must select the method that best determines the value of its residue gas or gas plant products. The selected criterion should either:

- Reflect most closely the circumstances surrounding the disposition of the lessee's residue gas or gas plant products, or
- Be the most relevant factor in valuing the lessee's residue gas and gas plant products.

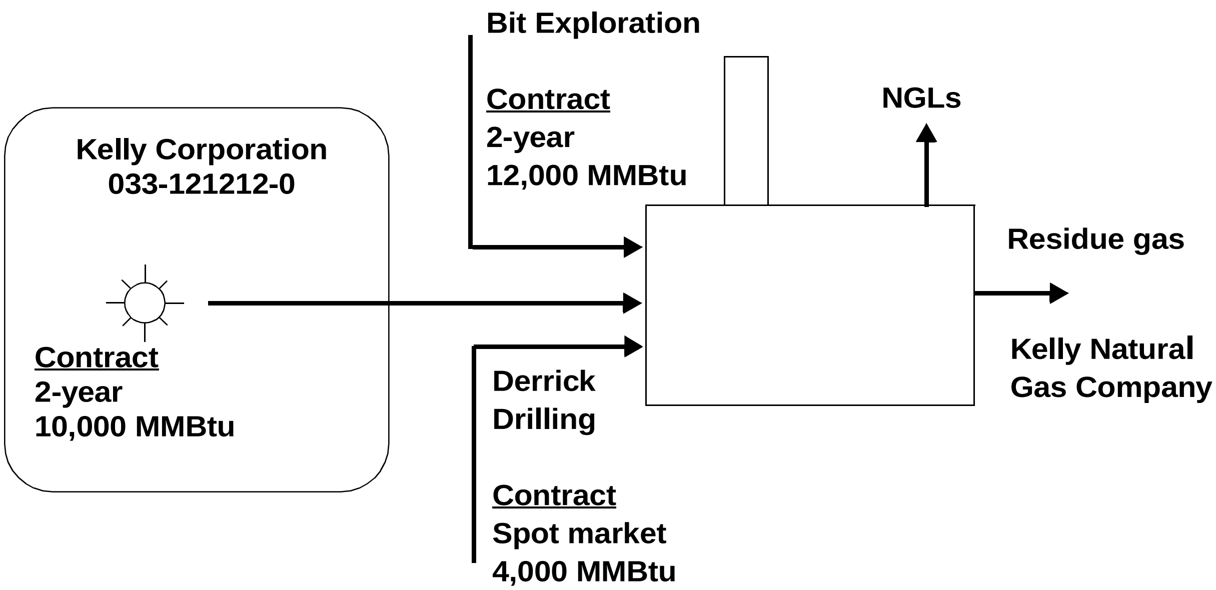
For example, if comparable arm's-length contracts exist at the plant or nearby plants as required under the first benchmark, but the lessee's gross proceeds are less than the gross proceeds under those contracts, the gross proceeds under the most comparable arm's-length contract would be used to establish value. If no arm's-length contracts exist at the plant, the best determinant of value may be published prices adjusted for quality and transportation. Or, other factors such as weighted-average prices, contractually reduced prices for transportation, or certain non-arm's-length contract prices may be used in establishing value.

Published prices for residue gas may be found in the same publications listed for unprocessed gas (see "Second valuation benchmark: Other relevant information" on p. 4-21). Published prices for NGLs may be found in the *Oil Buyer's Guide*, *Platt's Oilgram Price Report*, or other industry publications.

4.2.2.3 Third valuation benchmark: Net-back or other reasonable valuation method

The third benchmark for valuing processed gas is the net-back method or any other reasonable method for valuing residue gas or gas plant products (30 CFR 206.153(c)(3)).

Figures 4-32 through 4-35 illustrate valuation of processed gas sold under non-arm's-length contracts. Values reported on Form MMS-2014 are shown in boxes.



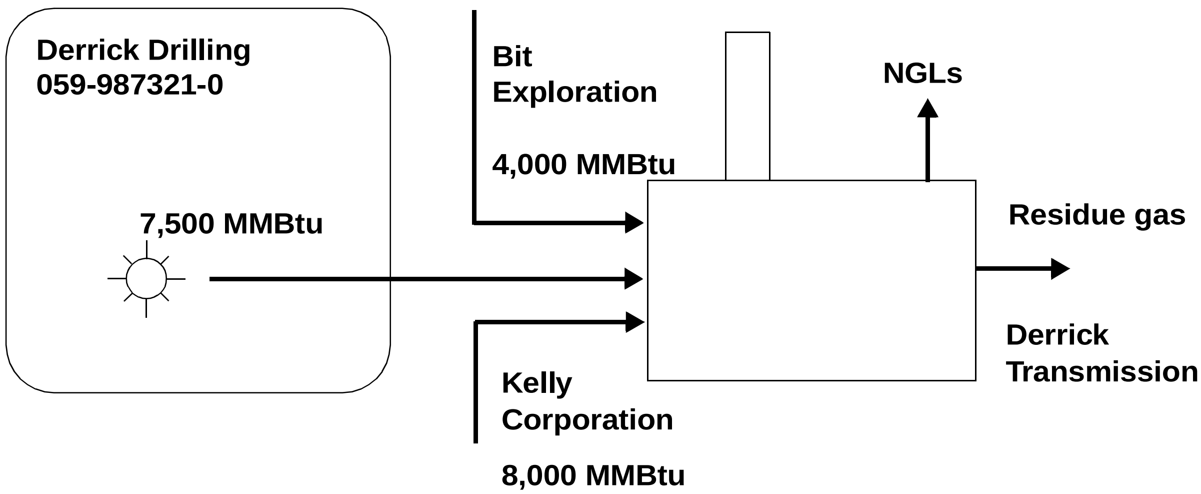
Kelly Corporation processes its gas and sells the residue gas to Kelly Natural Gas Company under a non-arm's-length contract for $2.10/MMBtu. Kelly Natural Gas Company also purchases all other residue gas from the plant.

Bit Exploration and Derrick Drilling sell their residue gas to Kelly Natural Gas Company under arm's-length contracts for $2.05/MMBtu and $2.15/MMBtu, respectively. The most comparable contract is Bit Exploration's contract.

Kelly Corporation's non-arm's-length contract price is equivalent to the price paid under Bit Exploration's contract. Therefore, Kelly Corporation's gross proceeds are acceptable for value under benchmark 1.

Residue gas value: 10,000 MMBtu x $2.10/MMBtu = $\boxed{\$21,000.00}$

FIGURE 4-32. **Valuation of residue gas under benchmark 1 where lessee's price is equivalent to prices paid under a comparable arm's-length contract**



Derrick Drilling processes its gas and sells the residue gas to Derrick Transmission under a non-arm's-length contract for $2.00/MMBtu.

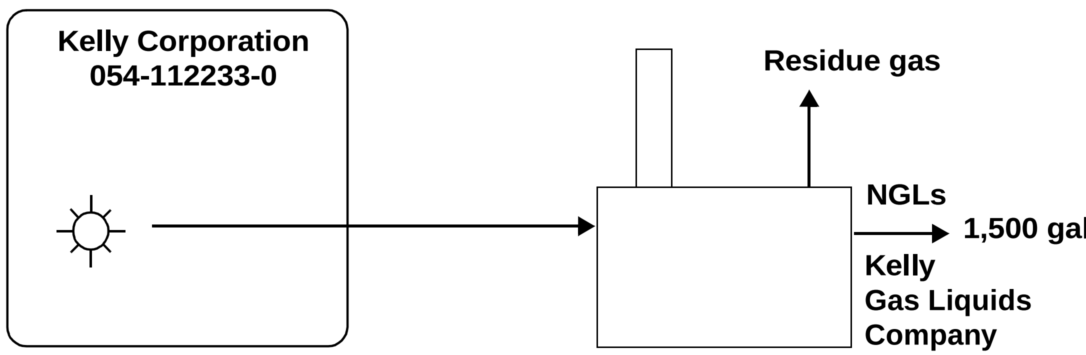
Derrick Transmission also purchases all other residue gas from the plant. Derrick Transmission pays $2.10/MMBtu and $2.05/MMBtu to Bit Exploration and Kelly Corporation, respectively, under arm's-length contracts.

Derrick Drilling's non-arm's-length price is less than the prices paid under arm's-length contracts for residue gas from the plant.

The most comparable contract at the plant is Kelly Corporation's contract. Derrick Drilling must use this contract to value its gas under benchmark 2.

Residue gas value: 7,500 MMBtu x $2.05/MMBtu = $\boxed{\$15{,}375.00}$

FIGURE 4-33. Valuation of residue gas under benchmark 2 where lessee's price is not equivalent to prices under comparable arm's-length contracts



Kelly Corporation sells NGLs to Kelly Gas Liquids Company under a non-arm's-length contract for $0.35/gal.

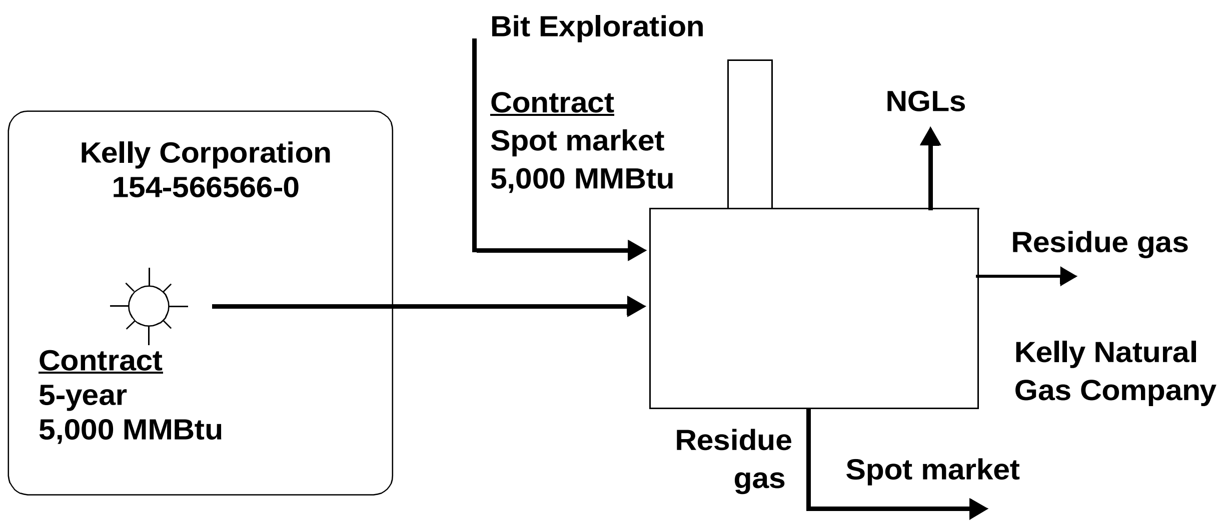
No sales or purchases of like-quality NGLs under comparable arm's-length contracts exist for the plant or nearby plants.

The price published in a national NGLs newsletter for the area is $0.37/gal.

A value of $0.37/gal is acceptable under benchmark 2.

NGL's value: 1,500 gal × $0.37/gal = $555.00

FIGURE 4-34. Valuation of NGLs under benchmark 2 where no comparable arm's-length contracts exist for the plant or nearby plants



Kelly Corporation sells all of its residue gas to Kelly Natural Gas Company under a non-arm's-length contract for $2.05/MMBtu.

Bit Exploration sells all of its residue gas under an arm's-length spot market contract at a current price of $2.12/MMBtu.

Bit Exploration's arm's-length spot price of $2.12/MMBtu is acceptable for valuing Kelly Corporation's gas under benchmark 2.

Residue gas value: 5,000 MMBtu x $2.12/MMBtu = $10,600.00

FIGURE 4-35. Valuation of residue gas under benchmark 2 where other residue gas from plant is sold under an arm's-length contract

4.2.3 Effects of regulated prices

The effects of Federal- or State-regulated prices on the value of the lessee's residue gas or gas plant products are the same as those discussed for unprocessed gas (see "Effects of regulated prices" on p. 4-32).

4.3 Gas Disposed of Under Special Contracts or Situations

Many contracts and arrangements for the disposition of unprocessed gas, residue gas, or gas plant products require special consideration for valuation purposes. This section, though not inclusive of all of the varied situations for the disposition of lease production, describes the following contracts and situations and discusses the applicable valuation procedures:

1. POP contracts,
2. Warranty contracts,
3. Exchange agreements,
4. Arrangements for the transportation and processing of the gas under a tariff structure,
5. Processing agreements that provide for compensation for the PVR (also known as "keep-whole" agreements),
6. Contracts providing for residue gas to be returned to the lease,
7. Production imbalances, and
8. Weighted-average (or pool) pricing.

4.3.1 POP contracts

A POP contract is an agreement for the sale of gas prior to processing in which the value of the wet, unprocessed gas is based on a percentage of the proceeds the purchaser receives for the sale of residue gas and gas plant products attributable to processing the lessee's gas.

Prior to November 1, 1991, all gas sold under a POP contract was valued as processed gas (product codes 03, 05, 07, etc.) under 30 CFR 206.153 and 30 CFR 206.173. All lessees were required to file for transportation and processing allowances during this period. Effective November 1, 1991, gas sold under an **arm's-length** POP contract is valued as unprocessed gas (product code 04) under 30 CFR 206.152 and 30 CFR 206.172 (56 FR 46527, September 13, 1991). These lessees are not required to file for or claim an allowance on the Form MMS-2014. However, gas sold under a **non-arm's-length** POP contract continues to be reported as processed gas.

Indian lessees are required to file the appropriate allowance forms prior to the time or at the same time an allowance is claimed on the Form MMS-2014. (For allowance filing requirements, see Chapter 5, "Oil Transportation Allowances," Chapter 6, "Gas Transportation Allowances," and Chapter 7, "Gas Processing Allowances.")

The value of gas sold under a POP contract is determined as described below.

Situation 1. Gas produced prior to November 1, 1991, and sold under either an arm's-length or a non-arm's-length POP contract is valued as processed gas. The value is based on the full value of residue gas, gas plant products, and drip condensate recovered downstream from the point of title transfer without resorting to processing, less appropriate processing and/or transportation allowances.

Situation 2. Gas produced on or after November 1, 1991, and sold under an **arm's-length** POP contract is valued as unprocessed gas. The value is based on the gross proceeds accruing to the lessee under the contract, provided that the value for royalty purposes is not less than a minimum value equivalent to 100 percent of the value of the residue gas attributable to the processing of the lessee's gas.

Situation 3. Gas produced on or after November 1, 1991, and sold under a **non-arm's-length** POP contract is valued as processed gas.

The value is based on the full value of residue gas, gas plant products, and drip condensate recovered downstream from the point of title transfer without resorting to processing, less appropriate processing and/or transportation allowances.

Situation 4. Gas produced from an Indian lease and sold under **either** an arm's-length or non-arm's-length POP contract is valued under the lease terms, which may require accounting for comparison and major portion analyses (see "Accounting for Comparison" on p. 4-90 and "Major Portion Analysis for Indian Gas Leases" on p. 4-103).

The criteria for determining the lessee's gross proceeds under an arm's-length POP contract in situation 2 are the same as those for determining the gross proceeds under any other arm's-length contract for the sale of unprocessed gas. Transportation factors reflecting the costs of transporting the residue gas to a point away from the plant may be considered in determining the gross proceeds for valuation purposes. Likewise, deductions reflecting the volume of gas used for fuel or the liquids recovered during transportation to the plant may be included in determining the gross proceeds. (See "Valuation of unprocessed gas sold under an arm's-length contract" on page 4-9 for more details regarding the acceptance of gross proceeds in valuing unprocessed gas.) When determining the minimum value of 100 percent of the residue gas value, however, only the costs of transporting the residue gas to a sales point away from the plant may be deducted.

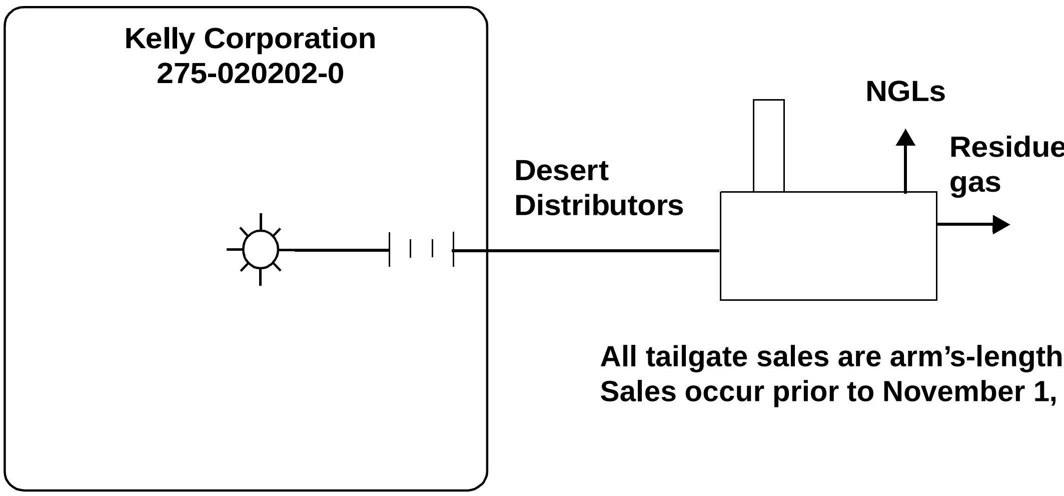
The value of the residue gas or gas plant products in situations 1 and 3 is determined as if the person actually selling or disposing of the residue gas or gas plant products were the lessee. That is, the circumstances surrounding the disposition at the tailgate (arm's-length or non-arm's-length sale) control the valuation of the residue gas or gas plant products. (See "Valuation of processed gas sold under an arm's-length contract" on page 4-41 and "Valuation of processed gas not sold under an arm's-length contract" on page 4-47 for more details about the valuation of residue gas and gas plant products.)

The processing allowance under a POP contract is based on the actual costs incurred under the contract. Actual costs under an arm's-length POP contract are generally the percentages of the residue gas and gas plant products values retained by the purchaser, plus any other fees that are a contractual cost of processing. The processing costs are limited to two-thirds of the value of the gas plant products. However, the lessee may request an exception to the two-thirds limitation (see Chapter 7, "Gas Processing Allowances").

The minimum value of **unprocessed** gas sold under a POP contract after November 1, 1991, situation 2, is 100 percent of the value of the residue gas at the tailgate of the plant. If the lessee incurs any costs for postplant transportation of the residue gas, those costs may be deducted in determining the tailgate value of the residue gas. However, the minimum value may not be further reduced for any costs associated with transporting the gas from the field to the plant.

Furthermore, consistent with all other Federal and Indian gas valuation, royalty is due on no less than the gross proceeds accruing under the lessee's POP contract.

Figures 4-36 through 4-39 illustrate valuation of gas disposed of under POP contracts. Values and allowances reported on Form MMS-2014 are shown in boxes.



**All tailgate sales are arm's-length.
Sales occur prior to November 1, 1991.**

Kelly Corporation sells gas to Desert Distributors under an arm's-length POP contract. Payment is based on 80 percent of Desert's net proceeds resulting from the sales of residue gas and NGLs attributable to processing Kelly's gas.

Settlement statement

Product	Volume		%		Price		Payment
Residue gas	10,000 MMBtu	×	80	×	$1.00/MMBtu	=	$8,000.00
NGLs	25,000 gal	×	80	×	$0.25/gal	=	$5,000.00
					Sales total		$13,000.00
					Fuel fee		($750.00)
					Net proceeds		$12,250.00

Fuel fee is for plant fuel only.

Kelly's gross proceeds = net proceeds = $12,250.00

FIGURE 4-36. Valuation of gas sold under an arm's-length POP contract before November 1, 1991: Processing costs do not exceed limitation (1 of 2)

Actual processing costs

Product	Volume		Price		Value		%		Processing cost
Residue gas	10,000 MMBtu	×	$1.00/ MMBtu	=	$10,000	×	20	=	$2,000.00
NGLs	25,000 gal	×	$0.25/ gal	=	$6,250	×	20	=	$1,250.00

Processing cost totals	$3,250.00
Fuel fee	$750.00
Total processing costs	$4,000.00

Processing allowance limit

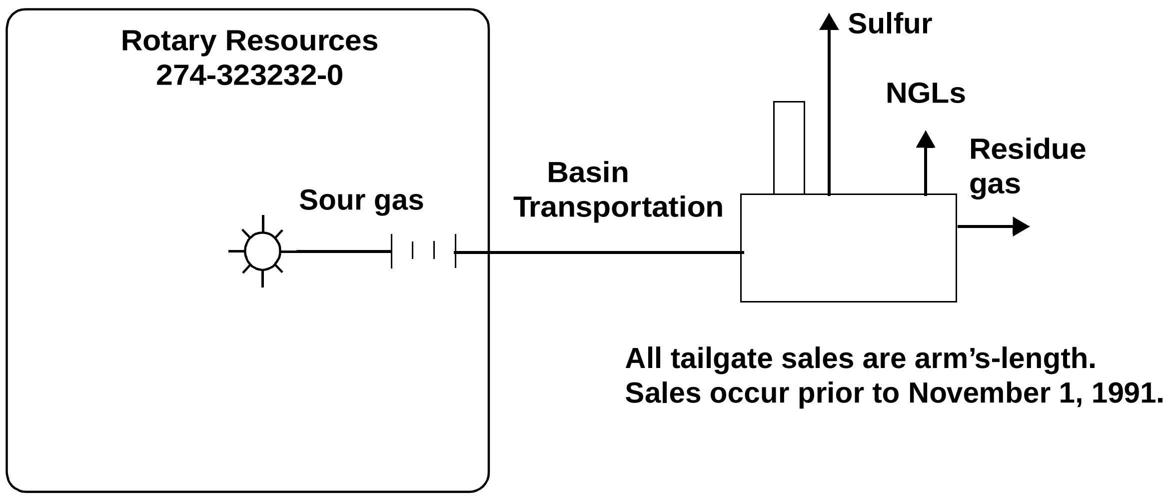
66 2/3% of NGLs value: 0.666667 × 25,000 gal × $0.25/gal = $4,166.67

Value for royalty

Product	Volume		%		Price		Value
Residue gas	10,000 MMBtu	×	100	×	$1.00/MMBtu	=	$10,000.00
NGLs	25,000 gal	×	100	×	$0.25/gal	=	$6,250.00

Processing allowance: $4,000.00

FIGURE 4-36. Valuation of gas sold under an arm's-length POP contract before November 1, 1991: Processing costs do not exceed limitation (2 of 2)



Rotary Resources sells gas to Basin Transportation under an arm's-length POP contract. Payment is based on 80 percent of Basin's net proceeds resulting from the sales of residue gas and NGLs attributable to processing Rotary's gas; Rotary does not receive compensation for other recovered products.

Settlement statement

Product	Volume		%		Price		Payment
Residue gas	10,000 MMBtu	×	80	×	$1.00/MMBtu	=	$8,000.00
NGLs	25,000 gal	×	80	×	$0.25/gal	=	$5,000.00
Sulfur	100 Mcf	×	0	×	$1.50/Mcf	=	$0.00

Sales total	$13,000.00
Fuel fee	($750.00)
Sulfur removal fee	($2,000.00)
Net proceeds	$10,250.00

Fuel fee is for plant fuel only.

Rotary's gross proceeds = $10,250.00

FIGURE 4-37. Valuation of gas sold under an arm's-length POP contract before November 1, 1991: Processing costs exceed limitation (1 of 3)

Actual processing costs for NGLs

Product	Volume		Price		Value		%		Processing cost
Residue gas	10,000 MMBtu	×	$1.00/ MMBtu	=	$10,000	×	20	=	$2,000.00
NGLs	25,000 gal	×	$0.25/ gal	=	$6,250	×	20	=	$1,250.00

Processing cost totals	$3,250.00
Fuel fee	($750.00)
Total processing costs	$4,000.00

Actual processing costs for sulfur

Product	Volume		Price		Value		%		Processing cost
Sulfur	100 Mcf	×	$1.50/ Mcf	=	$150.00	×	100	=	$150.00

Processing cost total	$150.00
Sulfur removal fee	$2,000.00
Total processing costs	$2,150.00

Processing allowance limits

66 2/3% value of NGLs: 0.666667 × 25,000 gal × $0.25/gal = $4,166.67

66 2/3% value of sulfur: 0.666667 × 100 Mcf × $1.50/Mcf = $100.00

FIGURE 4-37. Valuation of gas sold under an arm's-length POP contract before November 1, 1991: Processing costs exceed limitation (2 of 3)

Value for royalty

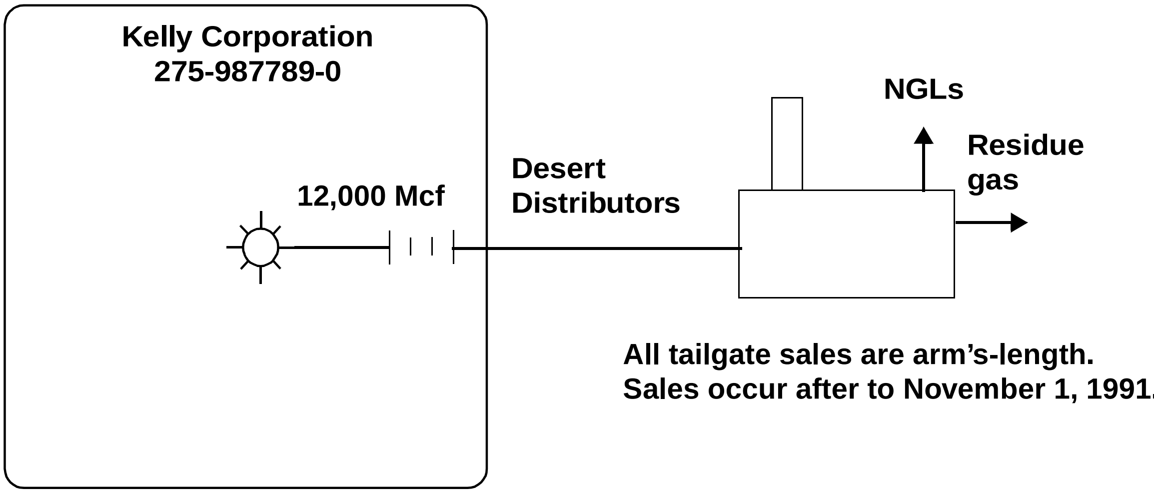
Product	Volume		%		Price		Value
Residue gas	10,000 MMBtu	×	100	×	$1.00/MMBtu	=	$10,000.00
NGLs	25,000 gal	×	100	×	$0.25/gal	=	$6,250.00
Sulfur	100 Mcf	×	100	×	$1.50/Mcf	=	$150.00

NGLs processing allowance: **$4,000.00**

Sulfur processing allowance: **$100.00**

Rotary may request an exception to the limitation on the sulfur processing allowance.

FIGURE 4-37. Valuation of gas sold under an arm's-length POP contract before November 1, 1991: Processing costs exceed limitation (3 of 3)



Kelly Corporation sells gas to Desert Distributors under an arm's-length POP contract. Payment is based on 80 percent of Desert's net proceeds resulting from the sales of residue gas and NGLs attributable to processing Kelly's gas.

Settlement statement

Product	Volume		%		Price		Payment
Residue gas	10,000 MMBtu	×	80	×	$1.00/MMBtu	=	$8,000.00
NGLs	25,000 gal	×	80	×	$0.25/gal	=	$5,000.00
					Sales total		$13,000.00
					Transportation fee		($750.00)
					Net proceeds		$12,250.00

Transportation fee is for moving lease gas to the plant.

Kelly's gross proceeds = $12,250.00

FIGURE 4-38. Valuation of gas sold under an arm's-length POP contract on or after November 1, 1991: Gross proceeds exceed minimum value (1 of 2)

Minimum value

Product	Volume		%		Price		Value
Residue gas	10,000 MMBtu	×	100	×	$1.00/MMBtu	=	$10,000.00

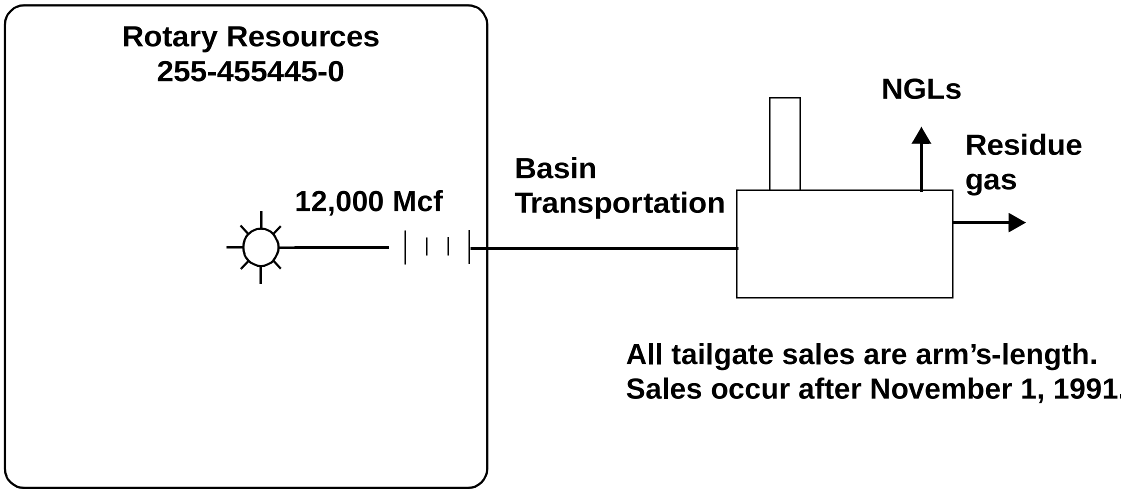
The minimum value of 100 percent of the residue gas value is determined at the plant tailgate and may not be reduced for the costs of transportation to the plant.

Value for royalty purposes

Value is based on the gross proceeds, but can never be less than the minimum value.

Value of the unprocessed gas is based on the gross proceeds: $\boxed{\textbf{\$12,250.00}}$

FIGURE 4-38. Valuation of gas sold under an arm's-length POP contract on or after November 1, 1991: Gross proceeds exceed minimum value (2 of 2)



Rotary Resources sells gas to Basin Transportation under an arm's-length POP contract. Payment is based on 60 percent of Basin's net proceeds resulting from the sales of residue gas and NGLs attributable to processing Rotary's gas.

Settlement statement

Product	Volume		%		Price		Payment
Residue gas	10,000 MMBtu	×	60	×	$1.00/MMBtu	=	$6,000.00
NGLs	25, 000 gal	×	60	×	$0.25/gal	=	$3,750.00
					Sales total		$9,750.00
					Transportation fee		($750.00)
					Net proceeds		$9,000.00

Transportation fee is for moving residue gas away from the plant.

Rotary's gross proceeds = net proceeds = $9,000.00

FIGURE 4-39. Valuation of gas sold under an arm's-length POP contract on or after November 1, 1991: Gross proceeds are less than minimum value (1 of 2)

Minimum value

Product	Volume		%		Price		Value
Residue gas	10,000 MMBtu	×	100	×	$1.00/MMBtu	=	$10,000.00

Residue gas transportation	($750.00)
100% residue gas value	$9,250.00

Value for royalty purposes

Value is based on the gross proceeds but can never be less than the minimum value.

Value of the unprocessed gas is based on the minimum value: $\boxed{\$9{,}250.00}$

FIGURE 4-39. Valuation of gas sold under an arm's-length POP contract on or after November 1, 1991: Gross proceeds are less than minimum value (2 of 2)

4.3.2 Warranty contracts

Warranty contracts are long-term sales contracts entered into prior to 1970 that obligate a specific quantity of gas to be delivered without regard to the origin or source of the gas. That is, the quantity of gas obligated under a warranty contract may come from fields or sources outside the fields designated in the contract, or the warranty contract may not specify the fields or sources for the gas. Warranty contracts may cover either unprocessed gas or residue gas.

MMS determines the value of gas sold under a warranty contract on a case-by-case basis by considering all valuation criteria applicable to either unprocessed gas or residue gas (30 CFR §§ 206.152(b)(2), 206.153(b)(2), 206.172(b)(2), and 206.173(b)(2), respectively). Because of the unique circumstances surrounding individual warranty contracts, MMS is unable to provide any general valuation guidance in this handbook.

A lessee selling gas under a warranty contract must submit a request for valuation to the Royalty Valuation Division. See “Important Addresses and Phone Numbers” on page 1-5.

The request must contain all available information relevant to the sale and valuation of the gas under the contract.

Any warranty contract already subject to a value determination by MMS or the U.S. Geological Survey Conservation Division and in effect prior to March 1, 1988, continues to be valued under that determination until modified by MMS under a valuation request by the lessee.

4.3.3 Gas exchange agreements

An exchange agreement for gas is an agreement for the delivery of unprocessed gas, residue gas, or gas plant products at a certain location by one party in exchange for the delivery of unprocessed gas, residue gas, or gas plant products at another location by a second party. The form of an exchange agreement varies widely, depending on the relationship between the two delivery points and the purpose of the agreement. If the two delivery points are on the same pipeline system, the agreement may represent nothing more than a transportation arrangement. By contrast, the delivery points may not be physically connected by the same pipeline, and the exchange agreement may represent multiple sales or other dispositions under one contract.

The valuation of unprocessed gas, residue gas, or gas plant products under an exchange agreement depends on whether the product is actually sold under the agreement or is subject to other dispositions. MMS recognizes three types of exchange agreements for valuation.

In the **first type** of exchange agreement, the lessee's unprocessed gas, residue gas, or gas plant products are delivered at one point on a pipeline or pipeline system and the same volumes, theoretically, are redelivered at another point downstream on the same system. A commodity price may or may not be specified in the agreement. If a commodity price is specified, the agreement generally provides that a price is paid to one party at one exchange point and the same price plus a location differential is paid to the second party at another exchange point. If a commodity price is not specified, the agreement provides only for the payment of the location differential. The location differentials specified in these agreements are essentially a transportation charge. In both cases, the pipeline is obligated to return the production to the lessee. No sale takes place at the exchange points, and the only consideration passed is payment for transportation services. Royalty value is:

- Determined at the first sales point at or beyond the downstream exchange point,
- Based on whether the sale is arm's-length or non-arm's-length, and
- Never less than the lessee's gross proceeds.

The lessee's reasonable, actual costs of transporting the unprocessed gas, residue gas, or gas plant products are eligible for a transportation allowance.

In the **second type** of exchange agreement, the pipeline system carrying the unprocessed gas, residue gas, or gas plant products exchanged at one location is separate and distinct from the pipeline system carrying the unprocessed gas, residue gas, or gas plant products exchanged at the second location. The lessee relinquishes possession and title to its production at the first point of exchange and acquires possession and title to other production at the second point of exchange.

A commodity price may or may not be specified in the agreement, but no consideration is paid apart from a quality and/or location differential. The exchange of unprocessed gas, residue gas, or gas plant products under this type of agreement is considered a disposition of lease production but not a sale under an arm's-length contract. If the unprocessed gas, residue gas, or gas plant products are not sold after the initial exchange, royalty value is determined under the non-arm's-length benchmark system at the first point of exchange where the lessee relinquishes title to its Federal or Indian unprocessed gas, gas residue, or gas plant products. If the lessee sells the unprocessed gas, residue gas, or gas plant products after the exchange, royalty value is:

- Based on the total consideration received by the lessee from both the exchange and the subsequent sale,
- Based on whether the sale is arm's-length or non-arm's-length, and
- Never less than the lessee's gross proceeds.

The lessee's reasonable, actual costs of transporting the unprocessed gas, residue gas, or gas plant products are eligible for a transportation allowance.

In the **third type** of exchange agreement, the lessee relinquishes title to and receives consideration for its unprocessed gas, residue gas, or gas plant products at one exchange point. The lessee then receives title to and pays consideration for unprocessed gas, residue gas, or gas plant products at a second exchange point. The two exchange points may or may not be physically connected by the same pipeline system. The exchange agreement represents two distinct sales under one contract. Title to the unprocessed gas, residue gas, or gas plant products may be transferred at the initial exchange point, and a price may be specified in the agreement.

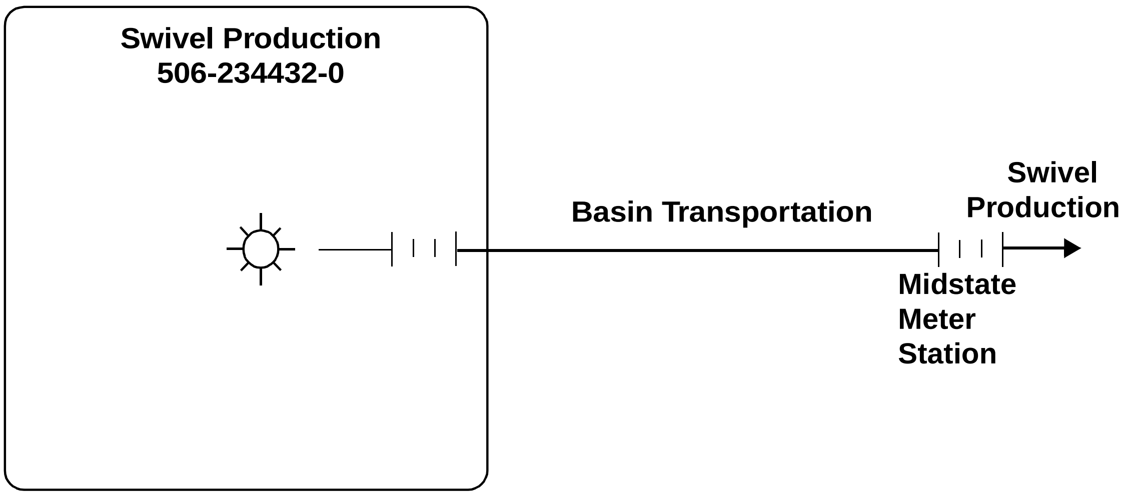
Because the agreement is conditioned on the lessee's purchase of production at a subsequent exchange point, the value specified in the exchange agreement does not necessarily reflect the total consideration received for production. Royalty value at the initial exchange point is:

- Based on the total consideration ultimately received for the unprocessed gas, residue gas, or gas plant products (including any premiums received for sales at or beyond the subsequent exchange point),

- Based on whether the sale is arm's-length or non-arm's-length, and
- Never less than the lessee's gross proceeds.

The lessee's reasonable, actual costs of transporting the unprocessed gas, residue gas, or gas plant products are eligible for a transportation allowance.

Figures 4-40, 4-41, and 4-42 illustrate valuation of gas under the three exchange agreements recognized by MMS.



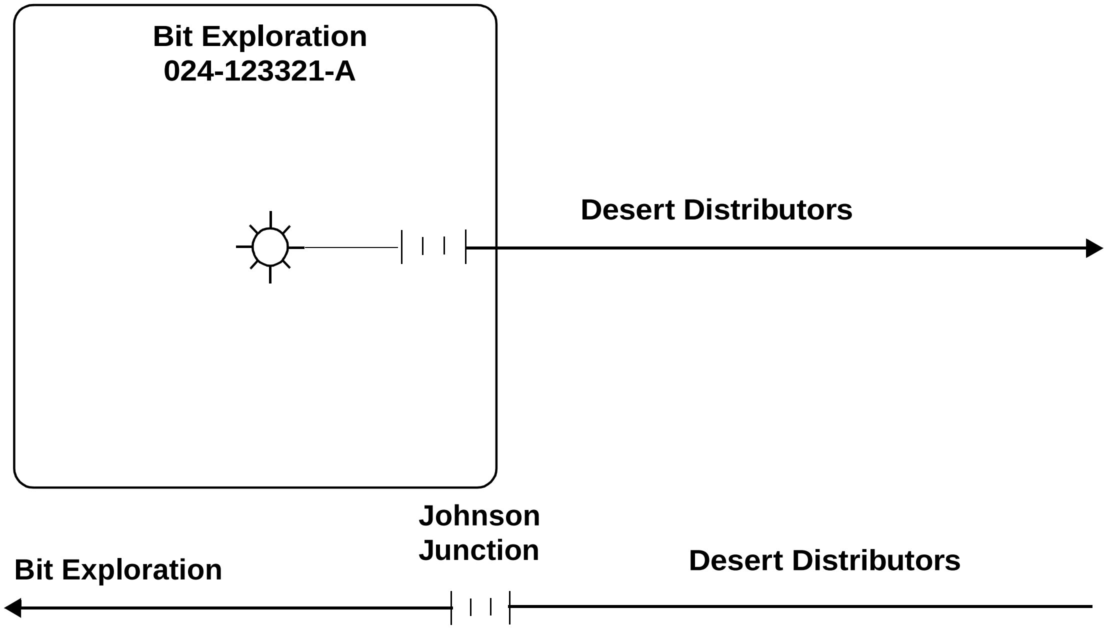
Swivel Production delivers gas at the wellhead to Basin Transportation under an arm's-length exchange agreement for the Anadarko Basin spot price. Basin delivers gas to Swivel at the Midstate Meter Station for the Anadarko Basin spot price plus a premium of $0.20/Mcf for location difference.

No consideration is actually paid except for the premium of $0.20/Mcf. Therefore, the gas is not considered sold under the exchange agreement.

Value is determined at the first sales point downstream from the Midstate Meter Station.

A transportation allowance may be claimed for the $0.20/Mcf fee charged to Swivel.

FIGURE 4-40. Valuation of gas disposed of under an exchange agreement where no consideration is paid and the gas is redelivered to the lessee



Bit Exploration delivers gas at the wellhead to Desert Distributors under an arm's-length exchange agreement for $1.50/MMBtu. Desert delivers gas to Bit at Johnson Junction for $1.50/MMBtu plus $0.01/MMBtu contract premium.

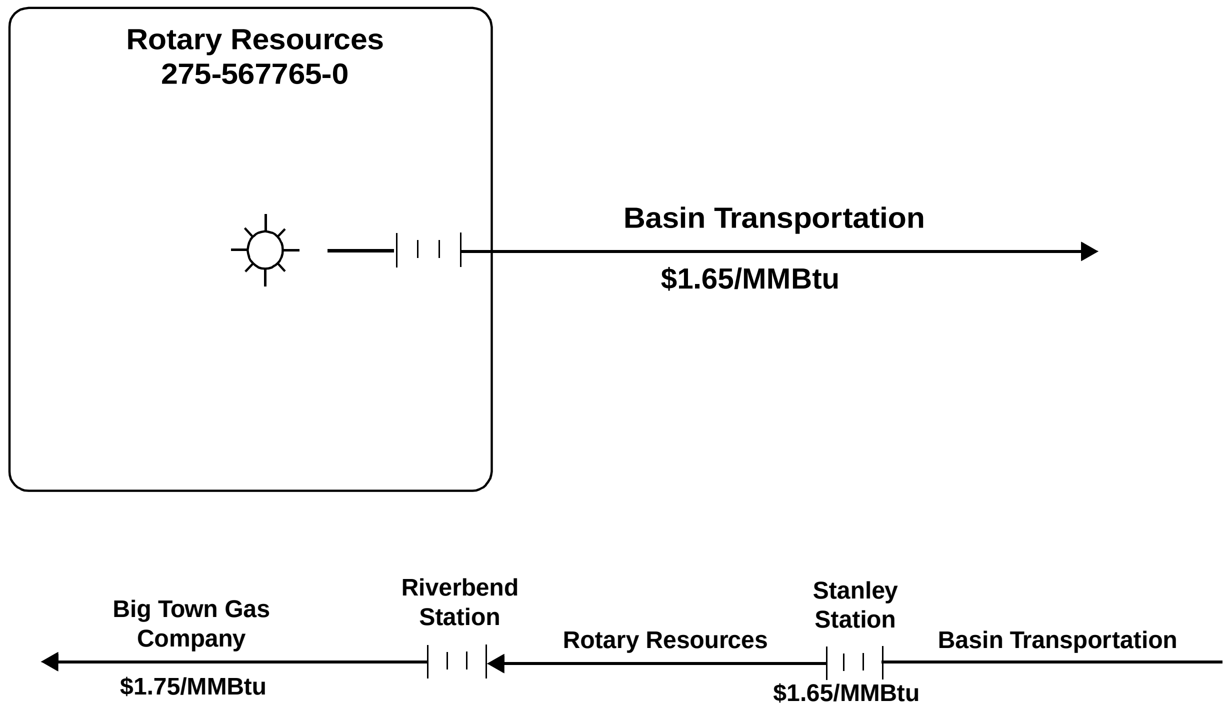
The two delivery points are remote and not physically connected.

No consideration is actually paid at either location, except for the premium at Johnson Junction.

The exchange agreement is not considered a wellhead sales contract.

Gas is valued at the lease under the second benchmark based on relevant valuation criteria.

FIGURE 4-41. Valuation of gas disposed of under an exchange agreement where no consideration is paid and the exchange points are not physically connected



Rotary Resources delivers gas to Basin Transportation under an arm's-length exchange agreement for $1.65/MMBtu. Basin redelivers gas to Rotary at Stanley Station for $1.65/MMBtu. Rotary Resources then sells the gas under an arm's-length contract to Big Town Gas Company for $1.75/MMBtu.

Consideration is actually paid at both exchange locations.

Royalty value for production from the Rotary Resources lease is determined by Rotary Resources' arm's-length sales price of $1.75/MMBtu to Big Town Gas Company at the Riverbend Station. This represents the total consideration paid for the gas.

If Rotary Resources incurs reasonable, actual costs to transport the gas to Riverbend Station, those costs are eligible for a transportation allowance.

FIGURE 4-42. Valuation of gas disposed of under an exchange agreement where actual consideration is paid to the lessee on delivery

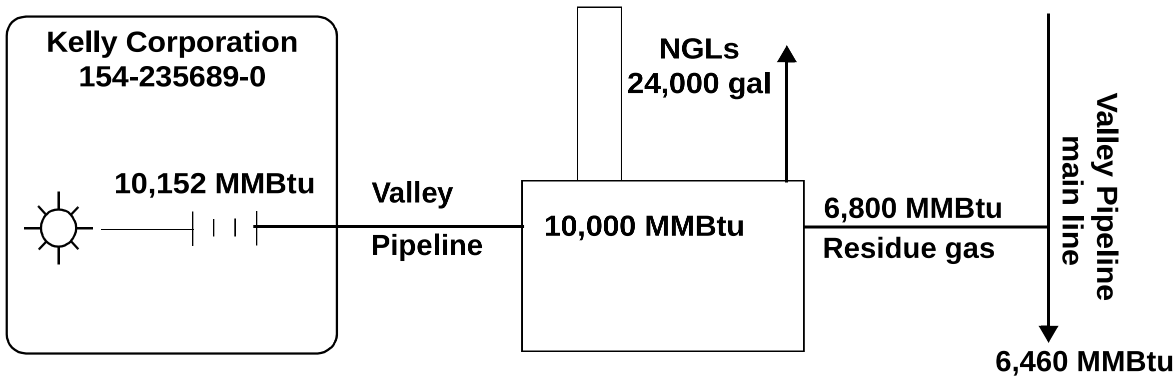
4.3.4 Arrangements providing for transportation and processing under a tariff

In certain pipeline systems, the owner/operator of the system provides services to the system's users and charges fees for those services based on a tariff. The user may be the lessee or another party that has purchased the lessee's gas. The services normally provided on such a system are transportation, processing, and associated functions.

If the lessee sells its gas at the wellhead under an arm's-length contract, the purchaser of the gas becomes the system user, and the tariff fees assessed to the purchaser are passed on to the lessee through the payment for the gas. (The lessee does not retain any rights to processing the gas.) In this situation, the lessee's payment is typically based on the values of the residue gas and NGLs, less the tariff fees for transportation, processing, and related services. The value of the lessee's gas sold at the wellhead under these circumstances is governed by the guidelines for valuing unprocessed gas sold under an arm's-length contract. The value is based on the gross proceeds accruing under the contract, with such gross proceeds reduced for the costs of transportation and processing. The gas is reported as unprocessed gas, product code 04, on Form MMS-2014 as a one-line entry. Any deductions for the costs of placing the gas in marketable condition, which must be borne by the lessee, are not allowable and must be added back into the value.

If the lessee itself uses the system for the transportation and processing of the gas, the gas is considered processed for valuation purposes. The value is based on the full values of residue gas, NGLs, and drip condensate recovered downstream of the point of delivery into the system without resorting to processing, less transportation and processing allowances. The allowances are calculated based on the actual costs incurred under the tariff. Residue gas (product code 03), NGLs (product code 07), and drip condensate (product code 05), along with a transportation allowance (transaction code 11) and a processing allowance (transaction code 15), are reported on multiple lines on Form MMS-2014. Again, any tariff fees assessed for placing the gas in marketable condition are not allowable deductions.

Figures 4-43 and 4-44 illustrate valuation of gas placed into a system with tariff fees for transportation and processing. Values and allowances reported on Form MMS-2014 are shown in boxes.



Kelly Corporation sells gas at the wellhead to Valley Pipeline under an arm's-length contract for a price of $2.10/MMBtu less transportation and other fees listed below. Kelly also receives a liquids credit of $0.25/gal for NGLs attributable to processing Kelly's gas.

Field transportation	Processing fee	Main line transportation
1 1/2% fuel (152 MMBtu)[1]	4% fuel (400 MMBtu)[2]	5% fuel (340 MMBtu)[3]
$0.2075/MMBtu ($2,075.00)[2]	28% shrinkage (2,800 MMBtu)[2]	$0.2719/MMBtu ($1,756.47)[4]
	$0.145/MMBtu extraction ($1,450.00)[2]	
	$0.02/MMBtu dehydration ($200.00)[2]	
	$0.15/MMBtu purification ($1,500.00)[2]	

[1] Based on 10,152 MMBtu of gas at the wellhead.

[2] Based on 10,000 MMBtu of inlet gas.

[3] Based on 6,800 MMBtu of residue gas at the tailgate.

[4] Based on 6,460 MMBtu of residue gas transported to the main line.

FIGURE 4-43. Valuation of gas sold under an arm's-length wellhead contract where transportation and processing tariff fees are assessed (1 of 2)

Liquids credit

24,000 gal × $0.25/gal = $6,000.00

Revenue to producer

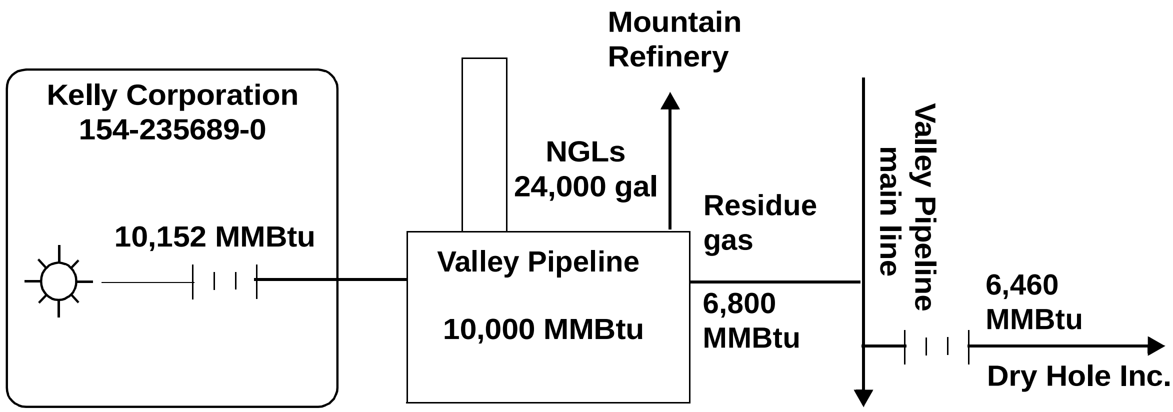
10,152 MMBtu	×	$2.10/MMBtu	=	$21,319.20
- 152 MMBtu	×	$2.10/MMBtu	=	(319.20)
- $0.2075/MMBtu	×	10,000 MMBtu	=	(2,075.00)
- 400 MMBtu	×	$2.10/MMBtu	=	(840.00)
- 2,800 MMBtu	×	$2.10/MMBtu	=	(5,880.00)
- $0.145/MMBtu	×	10,000 MMBtu	=	(1,450.00)
- $0.02/MMBtu	×	10,000 MMBtu	=	(200.00)
- $0.15/MMBtu	×	10,000 MMBtu	=	(1,500.00)
- 340 MMBtu	×	$2.10/MMBtu	=	(714.00)
- $0.2719/MMBtu	×	6,460 MMBtu	=	(1,756.47)
+ $0.25/gal	×	24,000 gal		6,000.00
				$12,584.53

Value for royalty purposes

The gas is valued as unprocessed. Value of the 10,152 MMBtu sold at the wellhead is based on the gross proceeds under the arm's-length contract. Dehydration ($200.00) and purification ($1,500.00) fees are costs to place the lease production in marketable condition and are not allowable deductions. The gross proceeds accruing to Kelly must be increased by the amount of these deductions.

Unprocessed gas value: $12,584.53 + $200.00 + $1,500.00 = $\boxed{\$14{,}284.53}$

FIGURE 4-43. Valuation of gas sold under an arm's-length wellhead contract where transportation and processing tariff fees are assessed (2 of 2)



Kelly Corporation transports and processes its gas in Valley Pipeline's system. Kelly sells the residue gas to Dry Hole Inc. under an arm's-length contract for $2.10/MMBtu; the sales point is at the Dry Hole-Valley interconnect. Kelly sells the NGLs to Mountain Refinery under an arm's-length contract for $0.25/gal.

Valley assesses the following tariffs to Kelly for transportation and processing.

Field transportation	Processing fee	Main line transportation
1 1/2% fuel (152 MMBtu)[1]	4% fuel (400 MMBtu)[2]	5% fuel (340 MMBtu)[3]
$0.2075/MMBtu ($2,075.00)[2]	28% shrinkage (2,800 MMBtu)[2]	$0.2719/MMBtu ($1,756.47)[4]
	$0.145/MMBtu extraction ($1,450.00)[2]	
	$0.02/MMBtu dehydration ($200.00)[2]	

[1] Based on 10,152 MMBtu of gas at the wellhead.

[2] Based on 10,000 MMBtu of inlet gas.

[3] Based on 6,800 MMBtu of residue gas at the tailgate.

[4] Based on 6,460 MMBtu of residue gas sold to Dry Hole.

FIGURE 4-44. Valuation of gas transported and processed by the lessee under a tariff (1 of 2)

VALUES AND ALLOWANCES FOR ROYALTY PURPOSES

The gas is valued as processed.

Residue gas value

$$6{,}800 \text{ MMBtu} \times \$2.10/\text{MMBtu} = \boxed{\$14{,}280.00}$$

Royalty is due on the 6,800 MMBtu of residue gas at the tailgate, rather than the 6,460 MMBtu actually sold to Dry Hole.

NGLs value

$$24{,}000 \text{ gal} \times \$0.25/\text{gal} = \boxed{\$6{,}000.00}$$

Transportation allowances

Field transportation costs for residue gas and NGLs:

Residue gas = 6,800 MMBtu × $0.2075/MMBtu = $1,411.00

$$\text{NGLs} = [\,400 \text{ MMBtu (fuel)} + 2{,}800 \text{ MMBtu (shrinkage)}\,] \times \$0.2075/\text{MMBtu} = \$664.00$$

Residue gas transportation allowance:

$$\$1{,}411.00 \text{ (field transportation)} + \$1{,}756.47 \text{ (main line transportation charge)} + \$714.00 \text{ (value of 340 MMBtu main line fuel at \$2.10/MMBtu)} = \boxed{\$3{,}881.47}$$

NGLs transportation allowance: $\boxed{\$664.00}$ **(field transportation)**

Processing allowance

$\boxed{\$1{,}450.00}$ **(extraction fee)**

The dehydration fee may not be deducted from value.

FIGURE 4-44. Valuation of gas transported and processed by the lessee under a tariff (2 of 2)

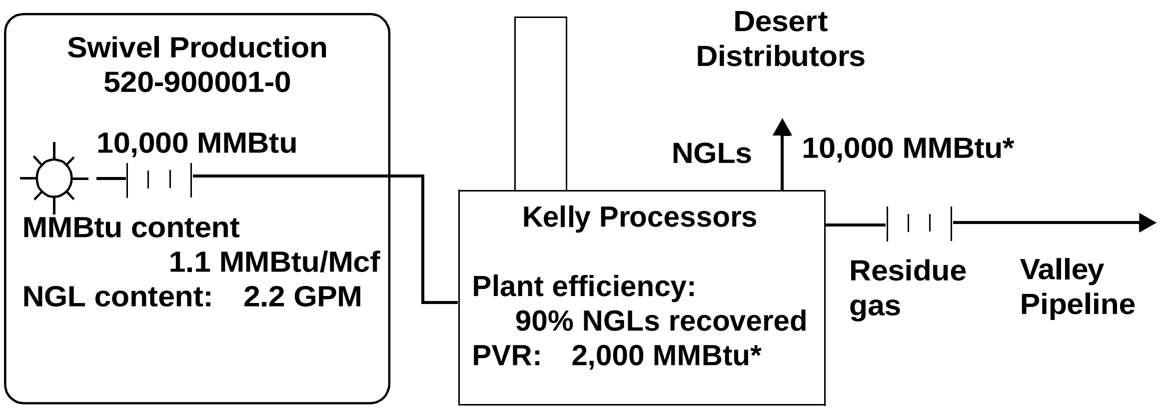
4.3.5 Keep-whole agreements

A keep-whole agreement is an agreement for the processing of the lessee's gas under which the lessee normally receives 100 percent of its attributable residue gas and consideration from the processor for its attributable PVR. The consideration for the lessee's PVR consists of either an amount of residue gas in Btus equivalent to the amount of Btus contained in the PVR or a cash payment for the PVR. If the lessee is compensated in residue gas Btus, that additional residue gas may be disposed of by the lessee in any manner it chooses.

In any event, the processor takes and sells the NGLs as compensation for the processing services. The lessee may also incur additional fees for processing the gas. For royalty purposes, the gas is valued as processed gas because the lessee has not sold the gas under an arm's-length contract prior to processing. The value for royalty purposes is 100 percent of the values of residue gas and NGLs attributable to processing the gas, less applicable transportation and processing allowances. The volume of NGLs attributable to the gas is determined under the provisions of 30 CFR 206.154 and 30 CFR 206.174 (see "Quantities and Qualities" on p. 2-3).

The value of NGLs is determined based on their market value (the plant owner's arm's-length sales price, for example). The value of the residue gas is based on whether the sale is arm's-length or non-arm's-length. The lessee's processing costs for the purpose of calculating a processing allowance are calculated as the difference between the value of the compensation received for the PVR and the value of the attributable NGLs at the tailgate, plus any other fees incurred for processing.

Figure 4-45 illustrates valuation of gas processed under a keep-whole agreement. Values and allowances reported on Form MMS-2014 are shown in boxes.



Swivel Production processes gas under an arm's-length processing agreement with Kelly Processors.

The agreement specifies that all of Swivel's attributable residue gas be delivered to Swivel at the plant tailgate and title to all NGLs recovered from Swivel's gas pass to Kelly.

Kelly pays Swivel for its attributable PVR. The payment for PVR is an amount of residue gas containing an equivalent amount of MMBtus as contained in the PVR.

***8,000 MMBtu of residue gas are attributable to Swivel. Therefore, Kelly delivers an additional 2,000 MMBtu of residue gas to Swivel. Swivel sells 10,000 MMBtu of residue gas to Valley Pipeline under an arm's-length contract at a price of $1.50/MMBtu. Kelly sells the NGLs to Desert Distributors under an arm's-length contract at a price of $0.23/gal.**

Residue gas value: $8{,}000\text{ MMBtu} \times \$1.50/\text{MMBtu} = \boxed{\$12{,}000.00}$

NGLs volume: $\dfrac{2.2\text{ GPM} \times 10{,}000\text{ MMBtu} \times 90\%}{1.1\text{ MMBtu/Mcf}} = 18{,}000\text{ gal}$

NGLs value: $18{,}000\text{ gal} \times \$0.23/\text{gal} = \boxed{\$4{,}140.00}$

Processing allowance:

$$\$4{,}140.00 - (2{,}000\text{ MMBtu} \times \$1.50/\text{MMBtu}) = \boxed{\$1{,}140.00}$$

FIGURE 4-45. Valuation of gas processed under a keep-whole agreement

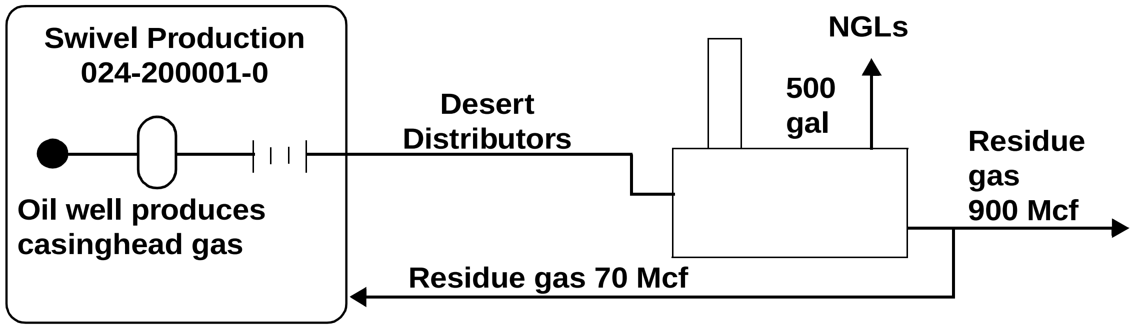
4.3.6 Residue gas returned to lease

Many casinghead gas and POP contracts provide an option for the lessee to have all or a portion of the lessee's attributable residue gas returned for use on the lease. Such use is normally for beneficial purposes, such as fuel for production equipment or injection for pressure maintenance, enhanced recovery, or gas lift.

Gas used on or for the benefit of the lease (as determined by BLM for onshore gas and MMS for offshore gas) is usually considered royalty free (30 CFR 202.150(b)). Gas removed from the lease but returned for beneficial use on the lease is also royalty free under certain conditions. However, if that gas is sold under a contract prior to being returned to the lease, that gas is subject to royalty, even though it may be used for the benefit of the lease (Petro-Lewis Corp., 108 IBLA 20, March 20, 1989).

Many POP contracts stipulate that the lessee is entitled to take in kind an amount of the attributable residue gas, up to the percentage specified in the contract, in lieu of monetary payment. The fact that the lessee exercises its option to receive a portion of its consideration in kind does not abrogate the sale. Thus, in this case, royalty is due on the portion of residue gas returned to the lease. However, not all contracts specify that residue gas returned to the lessee is a form of consideration passing to the lessee. Many types of casinghead gas contracts provide that the lessee's attributable residue gas may be returned to the lease for lease use, but any remaining portion of residue gas not required for lease use may be sold by the lessee's purchaser. In these cases, the returned residue gas is not royalty bearing, and the sold portion, for which the lessee normally receives compensation, is royalty bearing.

Figures 4-46 and 4-47 illustrate valuation of residue gas returned for lease use. Values and allowances reported on Form MMS-2014 are shown in boxes.



Swivel Production sells gas to Desert Distributors under an arm's-length POP contract. Swivel receives 70 percent of Desert's proceeds for the sale of residue gas and NGLs attributable to Swivel; however, Swivel may take in kind up to 70 percent of attributable residue gas for lease use.

Desert receives $1.50/Mcf for residue gas and $0.35/gal for NGLs.

1,000 Mcf of residue gas is attributable to Swivel; 900 Mcf is sold, and 70 percent of the remaining 100 Mcf (70 Mcf) is returned for lease use.

500 gal of NGLs are attributable to Swivel.

Returned residue gas is viewed as sold because it is a part of the total consideration received by Swivel for the sale of its gas. Royalty is due on the returned volumes.

The gas is valued as unprocessed gas.

Value is based on:

1. **Gross proceeds under the arm's-length contract, which includes the value of residue gas returned to the lease:**

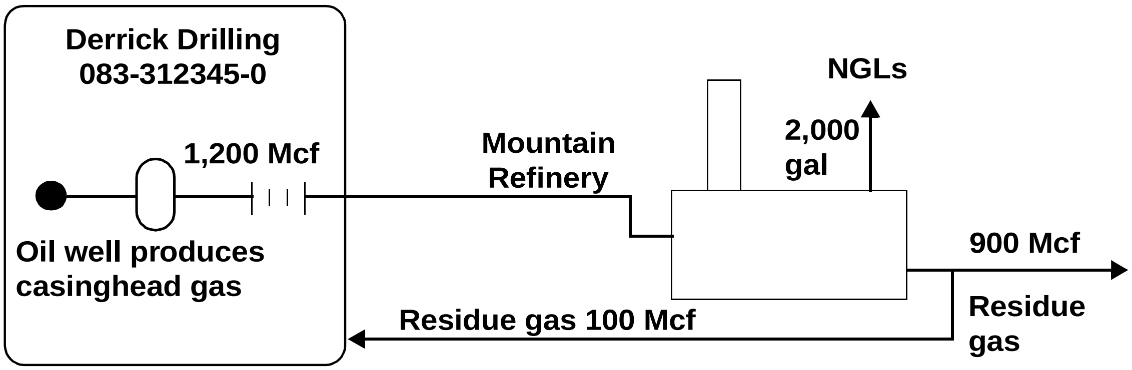
$$[(\,\textbf{500 gal} \times \textbf{\$0.35/gal}\,) + (\,\textbf{900 Mcf} \times \textbf{\$1.50/Mcf}\,)] \times \textbf{70\%}$$
$$+ (\,\textbf{70 Mcf} \times \textbf{\$1.50/gal}\,) = \textbf{\$1,172.50}\text{, } \underline{\textbf{OR}}$$

2. **A minimum value of 100 percent of value of residue gas:**

$$\textbf{1000 Mcf} \times \textbf{\$1.50/Mcf} = \textbf{\$1,500.00}$$

Unprocessed gas value: $\boxed{\textbf{\$1,500.00}}$

FIGURE 4-46. Valuation of residue gas returned to the lease where the gas is sold under an arm's-length POP contract after November 1, 1991



Derrick Drilling sells gas to Mountain Refinery under an arm's-length casinghead contract. However, Derrick reserves the rights to its residue gas for lease use. Excess residue gas not returned is sold by Mountain.

Derrick's payment is based on the product of its allocated NGLs volume multiplied by 40 percent of a specified NGLs posted price, plus the product of the excess residue gas multiplied by $1.50/Mcf.

NGLs posted price is $0.35/gal.

1,000 Mcf of residue gas is attributable to Derrick; 900 Mcf is sold, and 100 Mcf is returned for lease use.

Because the returned residue gas is not sold, no royalty is due on that gas. However, the gas is valued as processed gas because Derrick retains rights to the residue gas returned for lease use.

The processing allowance is based on the difference between the value of the NGLs and the payment received for the NGLs.

Reside gas value: 900 Mcf × $1.50/Mcf = $1,350.00

NGLs value: 2,000 gal × $0.35/gal = $700.00

Processing allowance: $700.00 – $280.00 = $420.00

FIGURE 4-47. Valuation of residue gas returned to the lease where the gas is delivered under an arm's-length wellhead contract providing for the return

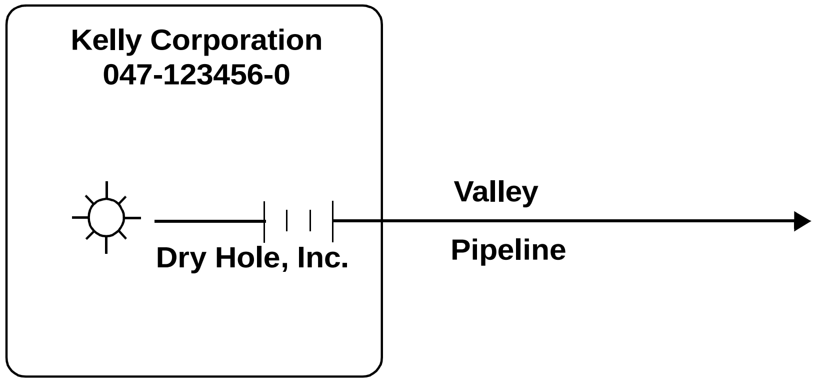
4.3.7 Production imbalances

Production imbalances result from the physical delivery of a different amount of gas into a pipeline system than the producer/lessee has delivered out of the pipeline system under the sales contracts entered into for the month in which the gas is produced. Production imbalances may involve unprocessed gas or residue gas.

Royalty is due on the gas when it is removed from the lease, **regardless of whether or not the gas is actually sold**. Therefore, royalty is due on that portion of gas physically delivered to the pipeline but not sold under the sales contract. Likewise, royalty is due only on that portion of gas actually removed from the lease in situations where the pipeline delivers more gas under contractual sales arrangements than the lessee delivers from the lease.

The value of unprocessed gas removed from the lease without a sale is determined under the second benchmark at 30 CFR §§ 206.152(c)(2) and 206.172(c)(2) because there are no gross proceeds accruing to the lessee as required under the first benchmark. Similarly, the value of residue gas transferred from the plant without a sale would be determined under the second benchmark at 30 CFR §§ 206.153(c)(2) and 206.173(c)(2). If a pipeline imbalance involves residue gas, the value of the gas plant products and the processing allowance are determined under the guidelines outlined previously, based upon the lessee's sales and processing contracts.

Figures 4-48 and 4-49 illustrate valuation of gas under pipeline imbalances. Values and allowances reported on Form MMS-2014 are shown in boxes.



Kelly Corporation sells unprocessed gas to Dry Hole Inc. at the wellhead, and Dry Hole transports the gas through Valley Pipeline.

Kelly nominates 10,000 MMBtu of unprocessed gas for sale at $1.80/MMBtu, and Dry Hole nominates that amount for transportation in Valley's pipeline.

Kelly produces 12,000 MMBtu of unprocessed gas.

Valley credits Kelly with a pipeline imbalance of 2,000 MMBtu.

Valuation for royalty purposes

Value is based on the full amount of unprocessed gas removed from the lease, including the pipeline imbalance credit.

Value of unprocessed gas sold:

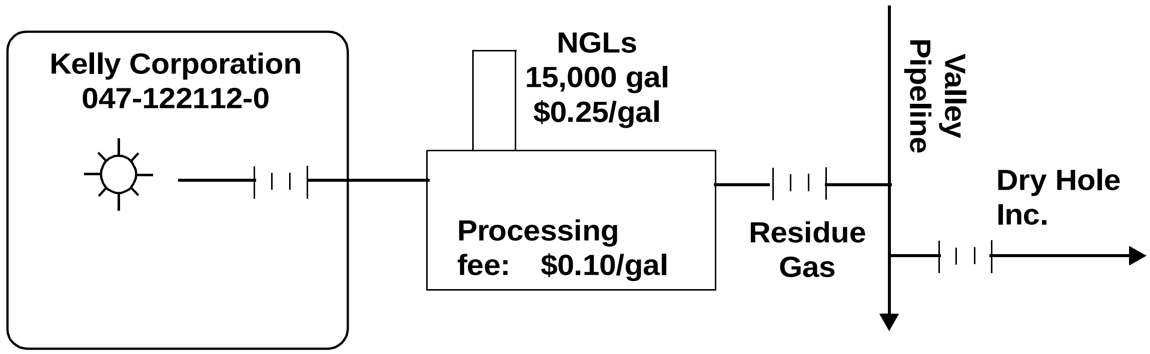
10,000 MMBtu sold × $1.80/MMBtu = $18,000.00

Value of unprocessed gas removed without sale:

2,000 MMBtu × $1.80/MMBtu = $3,600.00

Unprocessed gas value: $18,000.00 + $3,600.00 = $21,600.00

FIGURE 4-48. Valuation of unprocessed gas produced and delivered in excess of sales nominations



Kelly Corporation processes its gas, transports the residue gas through Valley Pipeline, and sells the residue gas to Dry Hole Inc. at Dry Hole's interconnect with Valley for $1.80/MMBtu.

Kelly pays Valley $0.10/MMBtu for transportation away from the plant.

Kelly nominates 10,000 MMBtu of residue gas for transportation through the pipeline. Because 12,000 MMBtu of residue gas from the plant is attributed to Kelly, Valley credits Kelly with a pipeline imbalance of 2,000 MMBtu.

<u>Valuation for royalty purposes</u>

Value is based on the full amount of residue gas attributable to Kelly, including the pipeline imbalance credit and NGLs value less transportation and processing allowances.

Value of residue gas sold: **10,000 MMBtu × $1.80/MMBtu = $18,000.00**

Value of residue gas removed without sale:

2,000 MMBtu × $1.80/MMBtu = $3,600.00

Total residue gas value: **$18,000.00 + $3,600.00 = $\boxed{\$21{,}600.00}$**

NGLs value: **15,000 gal × $0.25/gal = $\boxed{\$3{,}750.00}$**

Transportation allowance: **12,000 MMBtu × $0.10/MMBtu = $\boxed{\$1{,}200.00}$**

Processing allowance: **15,000 gal × $0.10/gal = $\boxed{\$1{,}500.00}$**

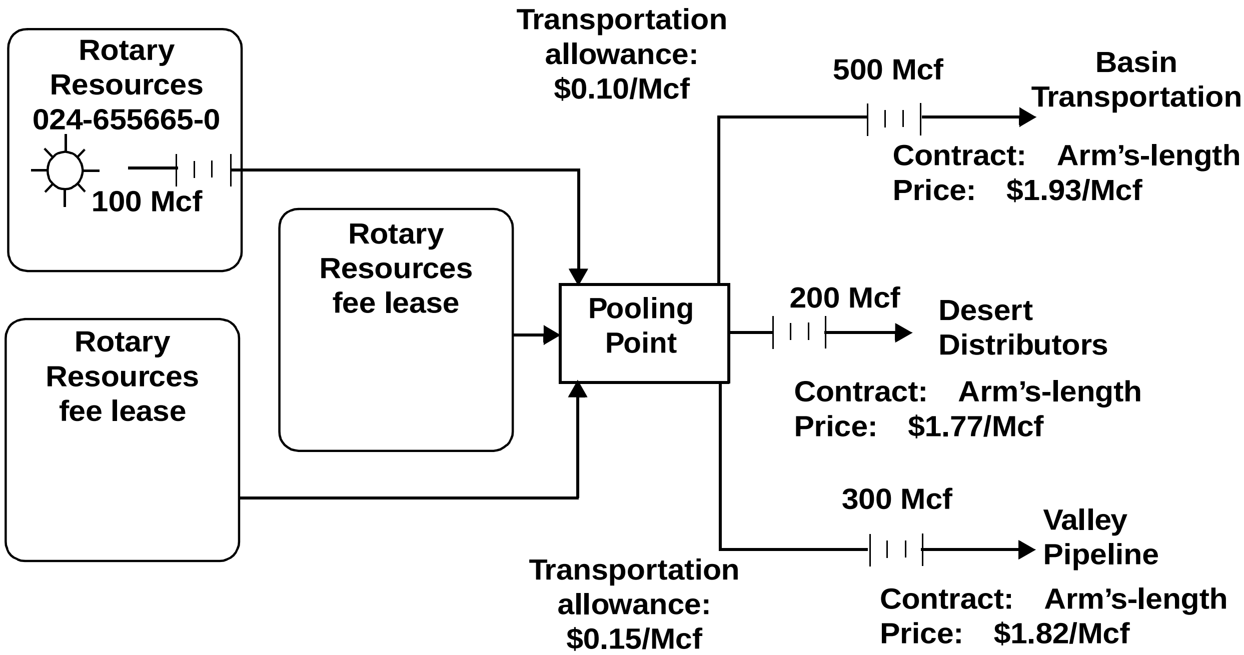
FIGURE 4-49. Valuation of residue gas produced and delivered in excess of sales nominations

4.3.8 Pool pricing

Gas pooling is a commonly used mechanism in the modern gas industry for the purpose of marketing gas or arranging the transportation of gas to a downstream sales point. Pooling occurs when gas from more than one lease, unitization agreement, or communization agreement is commingled at a single location and then sold to a number of purchasers, usually in the spot market.

When production from a lease or agreement can be traced physically and contractually to a point of sale, the value is based on the actual circumstances involved in the disposition of that production. When production cannot be traced physically and contractually to the point of sale, value is determined by assuming that the lease production is proportionately transported and sold to all outlets downstream of the last point at which the lease production has been commingled with production from other sources. The latter situation is considered pooling. Value in this situation is then determined by computing a weighted average of the prices at all downstream sales outlets. A weighted average of all transportation costs downstream of the pooling point is also computed for determining the transportation allowance to be deducted from the weighted-average value reported on Form MMS-2014.

Figure 4-50 illustrates valuation of gas that is pooled with other production before the sales point. Values and allowances reported on Form MMS-2014 are shown in boxes.



Value is based on gross proceeds under arm's-length contracts.

A weighted-average value is calculated because the production cannot be traced back to the lease.

<u>Weighted-average value</u>		<u>Weighted-average transportation allowance</u>	
500 Mcf × $1.93/Mcf =	$965.00	500 Mcf × $0.10/Mcf =	$50.00
200 Mcf × $1.77/Mcf =	$354.00	200 Mcf × $0.00/Mcf =	$00.00
300 Mcf × $1.82/Mcf =	$546.00	300 Mcf × $0.15/Mcf =	$45.00
1,000 Mcf	$1,865.00	1,000 Mcf	$95.00

Weighted-average value: $\frac{\$1{,}865.00}{1{,}000\text{ Mcf}} = \$1.865/\text{Mcf}$

Weighted-average transportation allowance: $\frac{\$95.00}{1{,}000\text{ Mcf}} = \$0.095/\text{Mcf}$

Value: 100 Mcf × $1.865/Mcf = $\boxed{\$186.50}$

Tranportation allowance: 100 Mcf × $0.095/Mcf = $\boxed{\$9.50}$

FIGURE 4-50. Valuation of gas by a weighted-average methodology

4.4 Accounting for Comparison

Accounting for comparison, or "dual accounting," is required under certain circumstances to determine the value of gas that has been processed. When dual accounting is required, royalty is based on the greater of the value of the gas before processing (unprocessed gas) or the value of the gas after processing (processed gas).

Dual accounting is mandatory in the following situations:

Situation 1. The lessee or the lessee's affiliate to whom the lessee has transferred the gas under a non-arm's-length contract processes the lessee's gas, **and** the residue gas after processing is not sold under an arm's-length contract (30 CFR 206.155(a) and 206.175(a)).

Situation 2. Prior to November 1, 1991, the lessee sells gas under a POP contract, **and** the residue gas after processing is not sold under an arm's-length contract (30 CFR §§ 206.153(a)(1), 206.155(a), 206.173(a)(1), and 206.175(a)).

Situation 3. On or after November 1, 1991, the lessee sells gas under a non-arm's-length POP contract, **and** the residue gas after processing is not sold under an arm's-length contract (56 FR 46527, September 13, 1991; 30 CFR 206.155(a); and 30 CFR 206.175(a)).

Situation 4. The terms of the leases, particularly Indian leases, require dual accounting, and the gas is actually processed (30 CFR 206.155(b) and 30 CFR 206.175(b)).

NOTE

Remember that dual accounting is normally required for Indian gas that is eventually processed, even if the gas is sold at the wellhead under an arm's-length contract containing no provisions tied to the processing of the gas.

The typical clause in standard Indian leases requiring dual accounting for Indian gas states:

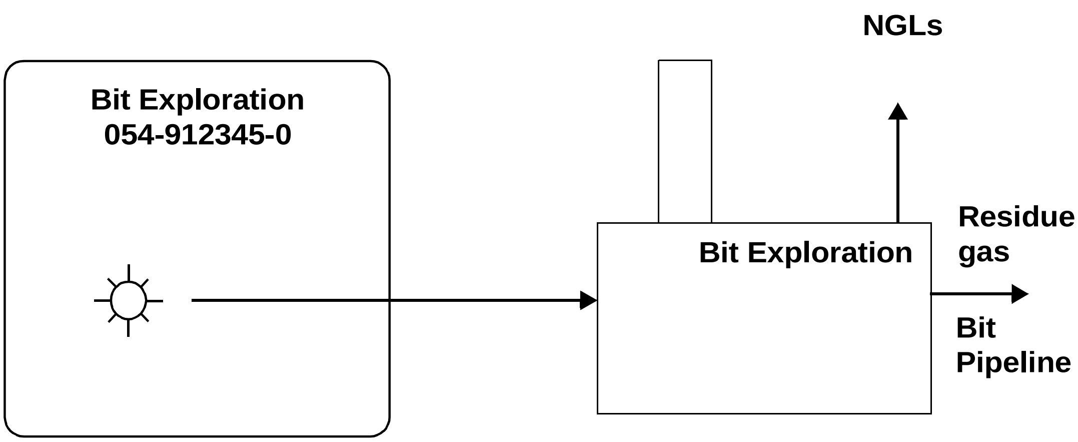
> It is understood that in determining the value for royalty purposes of products, such as natural gasoline, that are derived from treatment of gas, a reasonable allowance for the cost of

> manufacture shall be made, such allowance to be two-thirds of the value of the marketable product unless otherwise determined by the Secretary of the Interior on application by the lessee or on his own initiative, and that royalty will be computed on the value of gas or casinghead gas, or on the products thereof (such as residue gas, natural gasoline, propane, butane, etc.), **whichever is greater**.

Situation 1 above includes those arrangements under which the lessee sells unprocessed gas to an affiliate but retains and exercises the right to process the gas for the recovery of gas plant products. Under these arrangements, the residue gas is actually delivered to the affiliate at the tailgate under a non-arm's-length contract, and dual accounting is required regardless of the nature of any subsequent disposition of that residue gas.

Effective November 1, 1991, dual accounting is no longer required for gas produced from Federal leases and sold under an **arm's-length** POP contract when the attributable residue gas is sold under a non-arm's-length contract. Dual accounting is still required for gas produced from Indian leases and sold under an arm's-length POP contract when required by the lease terms.

Figures 4-51 through 4-54 illustrate how to determine when dual accounting is required.

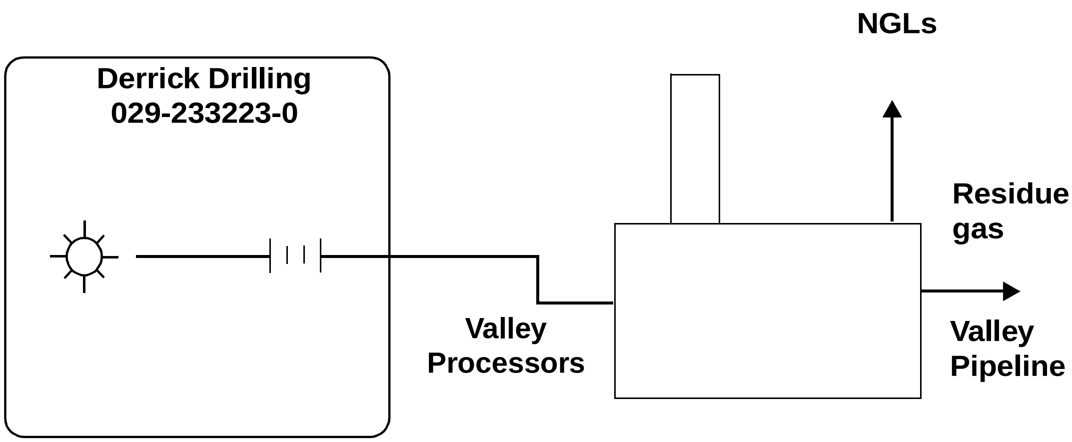


Bit Exploration processes its own gas at the plant for the recovery of residue gas and NGLs.

Bit Exploration sells gas to Bit Pipeline under a non-arm's-length contract.

Dual accounting is required because the residue gas is not sold under an arm's-length contract.

FIGURE 4-51. Valuation requiring dual accounting: Lessee processes gas and sells residue gas under a non-arm's-length contract



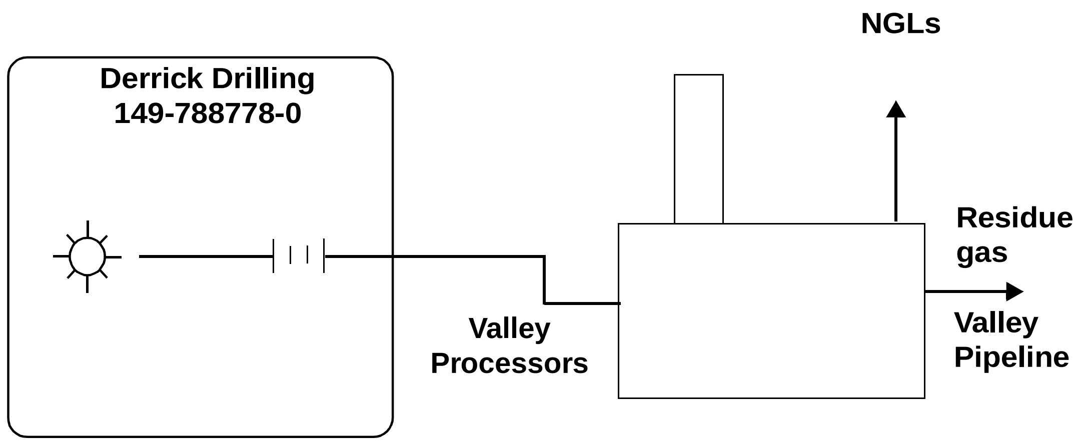
Derrick Drilling sells gas to Valley Processors under an arm's-length POP contract. Valley Processors sells residue gas to Valley Pipeline under a non-arm's-length contract.

Gas is sold before November 1, 1991.

Gas sold under an arm's-length POP contract before November 1, 1991, is valued as processed gas. Therefore, the value of the residue gas and NGLs is determined as if Valley Processors were the lessee.

Dual accounting is required because Valley Processors does not sell the residue gas under an arm's-length contract.

FIGURE 4-52. Valuation requiring dual accounting: Gas is sold under an arm's-length POP contract prior to November 1, 1991, but residue gas is not sold under an arm's-length contract



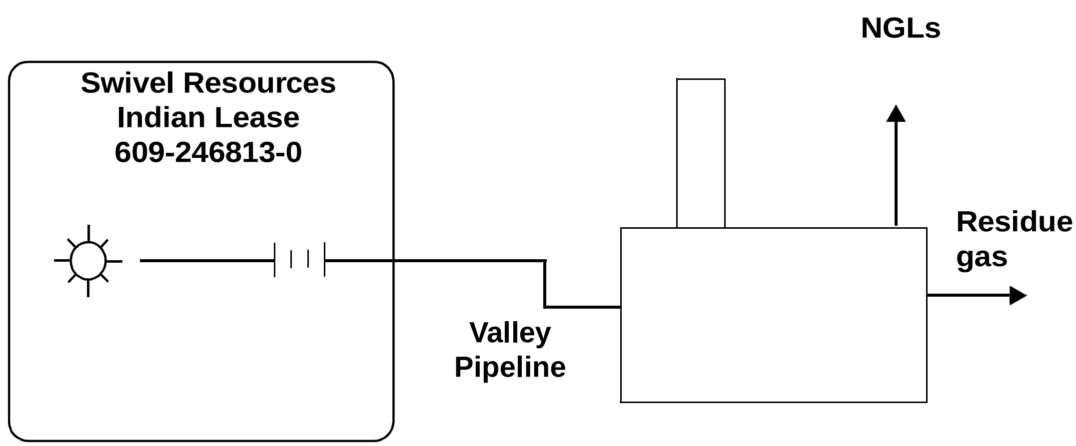
Derrick Drilling sells gas to Valley Processors under an arm's-length POP contract. Valley Processors sells residue gas to Valley Pipeline under a non-arm's-length contract.

The gas is sold on and after November 1, 1991.

Gas sold under an arm's-length POP contract on and after November 1, 1991, is valued as unprocessed gas.

Dual accounting is not required for unprocessed gas from Federal leases.

FIGURE 4-53. Valuation not requiring dual accounting: Gas is sold under an arm's-length POP contract after November 1, 1991



Swivel Resources sells gas at the wellhead to Valley Pipeline under an arm's-length contract. However, the gas is eventually processed.

Lease terms stipulate dual accounting.

Dual accounting is required even though the lessee sells gas at the wellhead and retains no rights to process the gas.

Note that if the gas was never processed, dual accounting would not be required.

FIGURE 4-54. Valuation requiring dual accounting: Gas is processed and Indian lease terms specify dual accounting

4.4.1 Dual accounting valuation requirements

As specified in 30 CFR 206.155(a), the value of gas under dual accounting is the greater of:

- The combined values of the residue gas and gas plant products, less applicable transportation and processing allowances, plus the value of any drip condensate recovered downstream from the point of title transfer without resorting to processing; or

- The value of the unprocessed (wet) gas.

The values of residue gas and gas plant products are determined under the instructions provided in "Processed Gas" on page 4-34. The value of unprocessed gas is determined under the instructions provided in "Unprocessed Gas" on page 4-2. If the value of the gas under dual accounting is based on the values of residue gas plus gas plant products less allowances, **allowance forms must be filed** for Indian leases prior to claiming an allowance on Form MMS-2014 (see Chapter 5, "Oil Transportation Allowances," Chapter 6, "Gas Transportation Allowances," and Chapter 7, "Gas Processing Allowances").

4.4.2 Theoretical dual accounting

In situations where dual accounting is required but the information necessary to determine the residue gas value, the gas plant products value, and/or the processing allowance costs are not available to the lessee, a method based on theoretical calculations may be used. This method is referred to as theoretical dual accounting. The lessee is advised, however, that every effort must be made to obtain the information required to accurately determine values of production under the guidelines contained in this handbook. The following procedures describe how to value production under theoretical dual accounting.

Theoretical NGL volume calculations

STEP 1. Determine the plant at which the gas is processed. This information may be obtained from the purchaser in most cases.

STEP 2. Calculate the amount of each NGL that is theoretically available from the lease. Periodic gas analyses (on a well or meter basis) must be performed for the gas removed from the lease to determine the GPM of each recoverable NGL; for example, ethane, propane, butane, etc. Multiply the GPM by the wellhead volume (wet gas volume) in thousand cubic feet (Mcf) to arrive at the theoretically available NGL volumes.

STEP 3. Calculate the NGLs recovered at the gas plant by multiplying the theoretically available NGL volumes by the appropriate plant efficiencies. Plant efficiency information may be obtained from the plant operator.

Theoretical residue gas volume calculations

STEP 1. Convert the recovered NGLs volume to equivalent gas volumes in Mcf and million British thermal units (MMBtus) by using the tables in the current *Gas Processors Suppliers Association (GPSA) Engineering Data Book, Volume II*.

STEP 2. Convert the plant fuel and incidental flare volumes incurred during processing to equivalent gas volumes in Mcf or MMBtu. Plant fuel and flare volumes (usually a percentage of plant inlet or residue gas volumes) may be obtained from the plant operator.

STEP 3. Calculate the theoretical residue gas volume by subtracting the Mcf or MMBtu equivalent NGL, plant fuel, and flare volumes from the wet gas volume.

Residue gas and NGL valuation

STEP 1. Calculate the value of the residue gas by multiplying the wellhead gas price in $/MMBtu by the calculated MMBtus of residue gas.

STEP 2. Determine the NGLs value by using pricing information for the area in which the plant is located. If specific information for sales at the plant is unavailable, NGL prices in commercial bulletins, such as *Platt's Oilgram Price Report*, for either Mont Belvieu, Texas, or Conway, Kansas, may be used, with a deduction for fractionation costs, provided that only a raw make is produced at the plant. Fractionation costs would be those representative of the costs incurred by fractionation plant operators in the area where the posted price is valid.

Transportation Allowances. Because the wellhead price under the arm's-length contract reflects the residue gas value at the wellhead, a transportation allowance for the residue gas may not normally be allowed when determining its value.

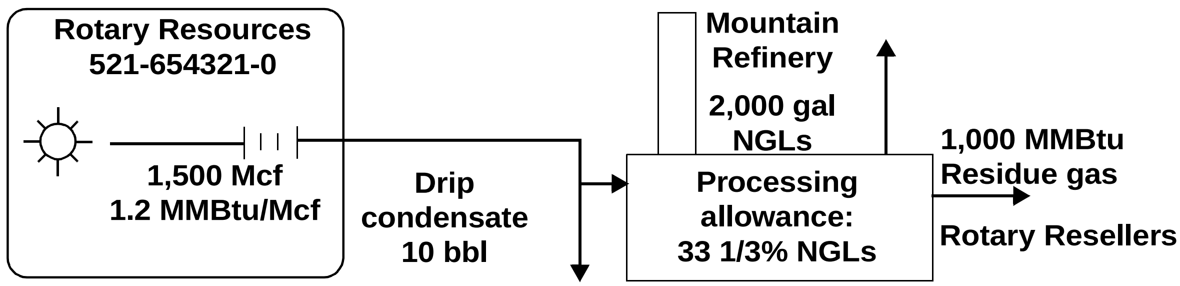
STEP 1. Calculate a transportation allowance for the NGLs for preplant transportation. The preplant transportation allowance is for the actual costs that would be incurred to transport the estimated recovered NGLs and the plant fuel and flare from the lease to the plant. The preplant transportation costs are obtained either from published tariffs or from the transporting pipeline company.

STEP 2. Calculate a transportation allowance for the NGLs for postplant transportation if the point of valuation for the NGLs is away from the plant. The postplant transportation allowance is for the costs that would be incurred to transport the NGLs from the plant to the point where the NGLs value is established. The postplant transportation costs are obtained either from published tariffs or from the transporting pipeline company.

Processing Allowance. Determine the processing allowance based on the actual costs incurred by the party processing the gas. The costs may be the plant processor's costs that are calculated and reported to MMS or the charges assessed under an arm's-length processing agreement with the plant. The processing allowance is limited to 66 2/3 percent of the value of the NGLs unless an exception is granted by MMS.

See the Dear Payor letter dated July 27, 1992, for additional details regarding the valuation of production under theoretical dual accounting.

Figures 4-55 and 4-56 illustrate valuation of gas under dual accounting. Values reported on Form MMS-2014 are shown in boxes.



Rotary Resources processes its gas and sells the residue gas under a non-arm's-length contract. Dual accounting is required.

	Residue gas	NGLs	Drip condensate
Contract:	**Non-arm's-length**	**Arm's-length**	**Arm's-length**
Sales point:	**Tailgate**	**Tailgate**	**Pre-plant**
Price	**\$1.55/MMBtu**	**\$0.25/gal**	**\$20.00/bbl**

All prices are acceptable for value calculation purposes.

Unprocessed gas value

1,500 Mcf × 1.2 MMBtu/Mcf × \$1.55/MMBtu = \$2,790.00

Processed gas value

Residue gas value: 1,000 MMBtu × \$1.55/MMBtu = \$1,550.00

NGL's value: 2,000 gal × \$0.25/gal = \$500.00

Processing allowance: \$500.00 × 0.333333 = (166.67)

Condensate value: 10 bbl × \$20.00/bbl = \$200.00

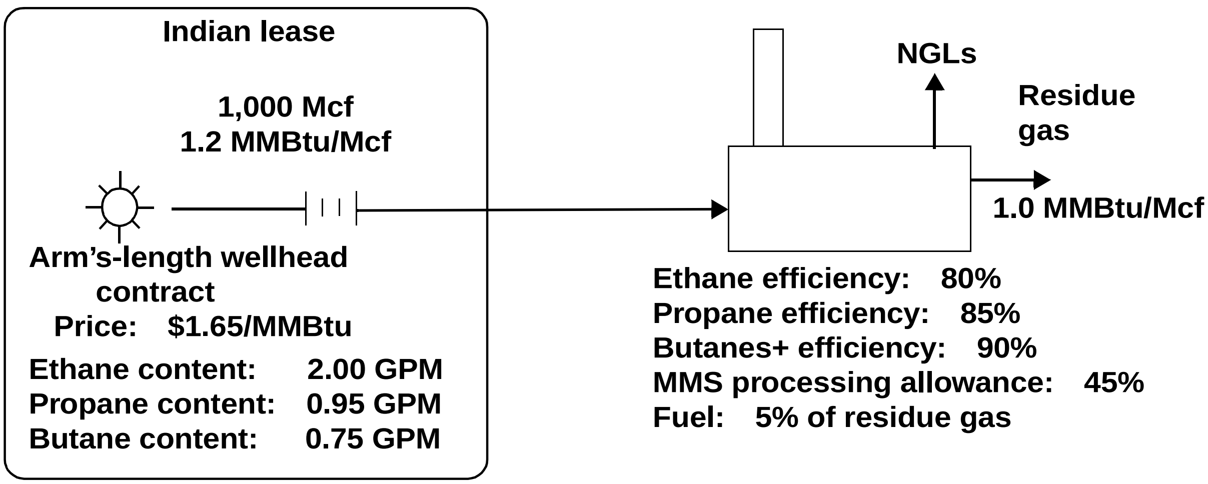
Total value: = \$2,083.33

Royalty valuation

Value is based on the unprocessed gas value because it is greater than the processed gas value.

Value: \$2,790.00

FIGURE 4-55. Valuation of gas under dual accounting



Gas is sold from the Indian lease under an arm’s-length wellhead sales contract. The gas is later processed, and the lessee is unable to acquire the actual processing information. The Indian lease terms require dual accounting.

<u>Unprocessed Gas Computation</u>

Unprocessed gas volume: 1,000 Mcf

Unprocessed gas value:

$$\$1.65/\text{MMBtu} \times 1.2\ \text{MMBtu/Mcf} \times 1{,}000\ \text{Mcf} = \$1{,}980.00$$

<u>Processed Gas Computations</u>

<u>NGL volumes</u>

NGL volume (gal) = Wellhead GPM × wellhead Mcf × plant efficiency

NGL volumes:	**Ethane**	**1,600.0 gal**
	Propane	**807.5 gal**
	Butanes+	**<u>675.0 gal</u>**
Total:	**NGL volume**	**3,082.5 gal**

FIGURE 4-56. Valuation of gas under theoretical dual accounting (1 of 3)

<u>Residue gas volume</u>

Residue gas volume (MMBtu) = wellhead MMBtu - shrinkage MMBtu - fuel MMBtu

Shrinkage MMBtus = NGL shrinkage factor × NGL volume (gal):

Product	Shrinkage factor (MMBtu/gal) *		Gal		Shrinkage (MMBtu)
Ethane	0.065869	×	1,600.00	=	105.39
Propane	0.090830	×	807.5	=	73.35
Butanes+	0.098917	×	675.0	=	66.77
				Total shrinkage:	245.51

*** NGL shrinkage factors from *GPSA Engineering Data Book*.**

Fuel = 5% × residue gas MMBtu (prior to fuel reduction)
= 5% × (1,200 MMBTU [wellhead] - 245.51 MMBtu [shrinkage])
= 47.72 MMBtu

Residue gas volume (MMBtu) = (1,000 Mcf × 1.2 MMBtu/Mcf) - 245.51 MMBtu - 47.72 MMBtu = 906.77 MMBtu

<u>Residue gas value</u>

Residue gas unit value: $1.65/MMBtu

Reside gas value: 906.77 MMBtu × $1.65/MMBtu = $1,496.18

<u>NGLs value</u>

Product	NGL unit values ($/gal) **		Gal		Value
Ethane	0.145	×	1,600.00	=	$232.00
Propane	0.250	×	807.5	=	201.88
Butanes+	0.375	×	675.0	=	253.13
				Total NGLs value:	687.01

**** Unit values from *Platt's Oilgram Price Report.***

FIGURE 4-56. Valuation of gas under theoretical dual accounting (2 of 3)

Processing allowance

Processing allowance: 45% × $687.01 (NGLs value) = $309.15

Royalty Value

Unprocessed gas value: $1,980.00

Processed gas value: $1,496.18 (residue gas value) + $687.01 (NGLs value) - $309.15 (processing allowance) = $1,874.04

Value is based on the unprocessed gas value because it is greater than the processed gas value.

Value: $\boxed{\$1{,}980.00}$

FIGURE 4-56. Valuation of gas under theoretical dual accounting (3 of 3)

4.5 Major Portion Analysis for Indian Gas Leases

The valuation of gas produced from Indian leases is subject to the same procedures, conditions, and limitations that apply to the valuation of processed and unprocessed gas produced from Federal leases. However, in addition to the accounting-for-comparison requirement, most Indian lease terms provide for, at the discretion of the Secretary of the Interior, a major portion analysis in addition to the accounting-for-comparison requirement to determine value for royalty purposes.

For those Indian leases requiring a major portion analysis, the value of the unprocessed gas, residue gas, or gas plant products in each case is the greater of the value determined by major portion analysis (known as the majority price) or the value determined based on the actual disposition of the production (arm's-length or non-arm's-length sales) (30 CFR 206.172(a)(3)(i) and 30 CFR 206.173(a)(3)(i)). The majority price is defined as the highest price paid or offered at the time of production for a major portion of production from the same field or area (for unprocessed gas) or from the same plant or nearby plants (for residue gas and gas plant products) (30 CFR 206.172(a)(3)(ii) and 30 CFR 206.173(a)(3)(ii)).

Compute the majority price as follows:

STEP 1. Array all arm's-length sales of like-quality unprocessed gas or residue gas (volumes in Mcf; prices in $/Mcf; volumes and prices at 1,000 Btu/ft^3 at 14.73 pounds per square inch, absolute [psia] at 60 °F) or all arm's-length sales of like-quality gas plant products (volumes and prices in applicable units) from the highest price at the top to the lowest price at the bottom.

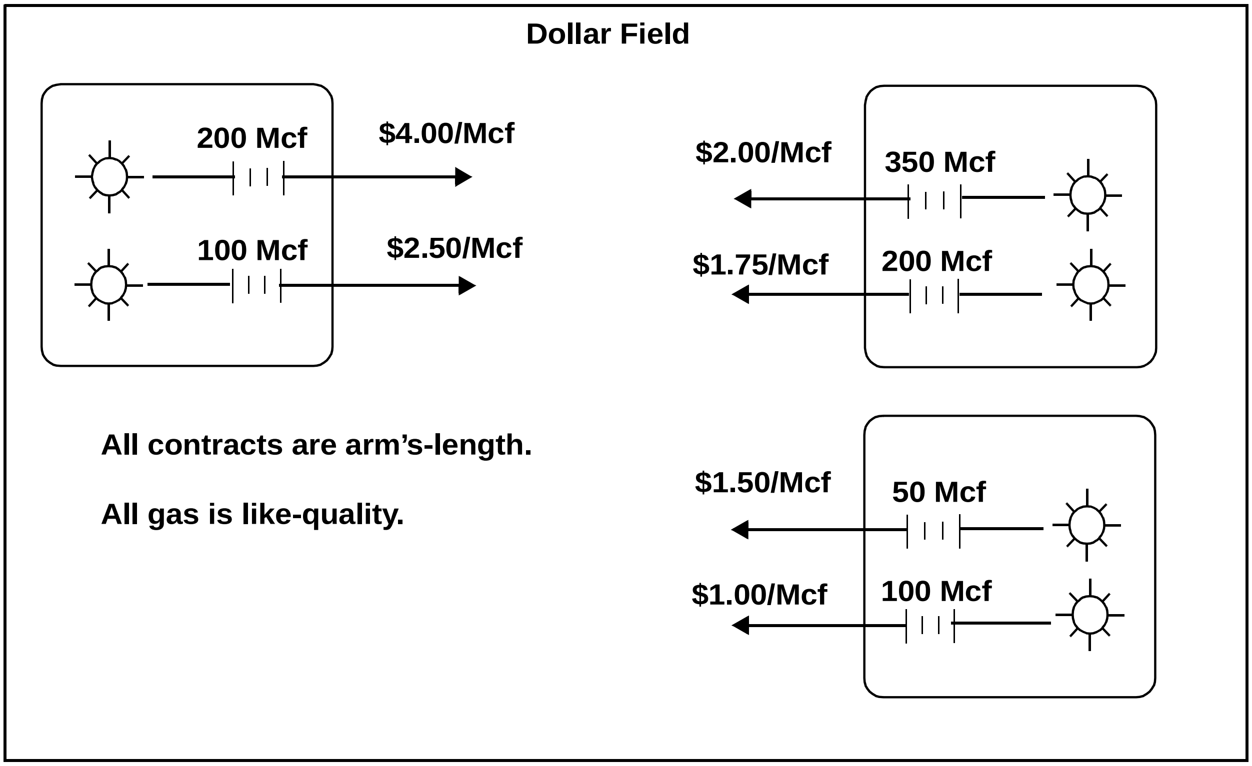
STEP 2. Starting at the bottom, sum the cumulative percentages that each volume represents of the total volume.

The majority price is that price at which 50 percent (by volume) plus 1 Mcf of gas (starting from the bottom) is sold, or for gas plant products, that price at which 50 percent (by volume) plus 1 unit is sold.

NOTE

Effective January 1, 2000, payors must value Indian gas production using the new Indian gas valuation regulations that were published in the *Federal Register* on August 10, 1999 (64 FR 43506).

Figure 4-57 illustrates calculation of a majority price for Indian gas.



Price ($/Mcf)	Volume (Mcf)	Cumulative (%)
4.00	200	100
2.50	100	80
2.00 *	350	70
1.75	200	35
1.50	50	15
1.00	100	10
	1,000	100

* The price at which 50 percent plus 1 Mcf of gas was sold is the majority price.

FIGURE 4-57. Valuation of gas under major portion analysis

5. Oil Transportation Allowances

This chapter describes the procedures for calculating and reporting transportation allowances for Federal and Indian oil, condensate, and other liquid production. Transportation allowances are granted only when the lessee incurs reasonable, actual, and necessary costs to transport oil to an off-lease point of value determination (sales, delivery, or approved off-lease point of royalty settlement).

The royalty value of oil is normally determined at the lease, unit, or CA (collectively referred to as the lease). However, value may also be determined at a point off the lease, and the lessee must incur the expense of delivering the oil to that point. In these cases, the lessee's reasonable, actual transportation costs (not to exceed 50 percent of the value of the oil) may be deducted as a transportation allowance. Transportation costs cannot be transferred between selling arrangements or to other products.

Indian lessees must submit an Oil Transportation Allowance Report, Form MMS-4110 documenting transportation allowances claimed on the Report of Sales and Royalty Remittance, Form MMS-2014. All transportation allowances reported on these forms are subject to audit. Federal lessees are no longer required to file allowance forms.

For Indian leases, discrepancies between the allowance forms and allowances reported on Form MMS-2014, as well as late or incorrect allowance forms or failure to file the appropriate allowance forms, could result in a disallowance of deductions claimed on Form MMS-2014, the assessment of interest, or both. The regulations covering oil transportation allowances for Federal leases are at 30 CFR 206.104 and 30 CFR 206.105. The regulations covering oil transportation allowances for Indian leases are at 30 CFR 206.54 and 30 CFR 206.55.

To ask questions about oil transportation allowances, contact the Royalty Valuation Division. See "Important Addresses and Phone Numbers" on page 1-5.

5.1 Determining if the Lessee is Entitled to Claim an Oil Transportation Allowance

Even though lessees may incur transportation costs, in certain situations the lessee is prohibited from claiming these costs as a transportation allowance. The following sections discuss these situations.

5.1.1 RIK oil

Onshore RIK oil. A transportation allowance may not be claimed for transporting onshore oil taken as royalty-in-kind (RIK) (30 CFR 208.8(a)).

Offshore RIK oil. A transportation allowance may be claimed for the reasonable, actual costs incurred to transport offshore oil taken as RIK to the delivery point specified in the contract between the RIK oil purchaser and the Federal Government. A transportation allowance may not be claimed for transporting RIK oil beyond the delivery point (30 CFR 208.8(b)).

5.1.2 Section 6 leases

Leases originally issued by the State of Louisiana under its 1942 lease form and now administered by MMS under Sections 6 and 7 of the OCSLA, 43 U.S.C. 1337 (1953) contain lease terms explicitly disallowing deductions from value or charges for gathering or transporting production to the purchaser. Thus, oil produced from these leases is not eligible for a transportation allowance. Leases issued under the 1942 lease form are:

- OCS 0002 through 0091
- OCS 0093 through 0183
- OCS 0194 through 0199
- OCS 0201 through 0211
- OCS 0216 through 0227
- OCS 0232 through 0309
- OCS 0311 through 0356
- OCS 0360 through 0402
- OCS-G 012345 through 012349

Lease numbers OCS 0092 and 0310 are exceptions and are not prohibited from filing a transportation allowance.

5.1.3 NPSLs

Net profit share leases (NPSLs) were issued under Section 8(a) of OCSLA. OCSLA required that alternative bidding systems be established for leases on the OCS. The *Federal Register* Notice entitled "Fixed Net Profit Share Bidding System for Outer Continental Shelf Oil and Gas Leases and Accounting Procedures for Determining Net Profit Share Payments: Final Rule" (45 FR 36784—May 30, 1980) established the accounting method to be used to report costs and revenues for NPSLs.

Rather than paying a fixed royalty, the NPSL operator pays a fixed percentage of the net profits based on the revenue received from the production and sale of oil and gas minus the cost of production. Under this system the lessee recovers expenses of exploration and development, plus a reasonable return on that investment, from production revenues prior to any net profit share payment to the Federal Government.

The MMS Director's approval of a Development and Coordination Document, combined with the language at 30 CFR 220.011(g) and 30 CFR 220.011(o), permits the lessee to include, in the NPSL capital account, allowable costs associated with transportation and processing. Thus, transportation and processing allowances for NPSLs should not be claimed as separate deductions on Form MMS-2014.

5.1.4 Exchange agreements

The costs incurred under certain types of exchange agreements may qualify for a transportation allowance (see Ch. 3, "Oil Valuation," and Ch. 4, "Gas Valuation").

For example, under an arm's-length exchange agreement, Basin Transportation (Basin) sells a specified volume of oil to Swivel Production (Swivel) for a posted price at point A. Swivel sells an equal volume of oil to Basin for the same posted price plus $1.50/bbl at point B. In this example, Swivel may claim a transportation allowance of $1.50/bbl.

5.1.5 Transportation factors

If an arm's-length contract or an arm's-length posted price includes a provision by which the listed price is reduced by a transportation factor and the lessee is paid a net amount by the purchaser, MMS considers this charge to be a transportation factor (30 CFR 206.105(a)(5) and 30 CFR 206.55(a)(5)). MMS does not consider the transportation factor to be a transportation allowance. MMS considers a transportation factor to be an adjustment to value rather than an out-of-pocket transportation expense.

In cases where the transportation charge is treated as an adjustment to value and considered to be a transportation factor, the transportation factor may be used in determining the lessee's gross proceeds. The lessee reports its royalty line net of the transportation charge. A separate transportation allowance line on Form MMS-2014 is not required. A transportation allowance Form MMS-4110 is not required from either Federal or Indian lessees in this case.

The transportation factor may not exceed 50 percent of the base price of the oil without MMS approval.

If the lessee has a marketing affiliate that meets the MMS definition of a marketing affiliate, and the marketing affiliate's arm's-length contract price is reduced by a transportation factor, MMS considers the transportation charge as a factor, not an allowance. The lessee reports the royalty line net of transportation without prior MMS approval.

5.1.6 Oil not in marketable condition

The lessee is required to place lease production in marketable condition at no cost to the lessor. A transportation allowance is not permitted for oil that is not in marketable condition. Any costs associated with placing the oil in marketable condition cannot be included as a transportation cost.

The lessee is responsible for bearing all marketing-related costs such as gathering, dehydration, nonallowable compression, initial separation, storage, measurement, treatment (such as sweetening or purification), market brokerage, or other marketing activities.

For example, if an arm's-length contract states that the lessee is charged $1/bbl for transportation, storage, and measurement, then the lessee must determine what costs are allocable to transportation, storage, and measurement, and deduct only the portion allocated to transportation.

Gathering. Gathering is defined as the movement of lease production to a central accumulation and/or treatment point on the lease, unit, or CA, or to a central accumulation or treatment point off the lease, unit, or CA as approved by BLM (onshore) or MMS (offshore).

Gathering is considered part of placing lease production in marketable condition and therefore is not allowable as a transportation cost. Gathering is not considered transportation of marketable lease production to a sales point off the lease.

The distinction between gathering, for which no deduction is permitted, and transportation, which allows for a deduction, hinges on a number of factors. Using a pipeline as an example, the following questions will aid in distinguishing between gathering and transportation:

- Does the pipeline segment lie entirely within the lease, unit, or CA?

  If the answer is "yes," the pipeline is a gathering line, and no deductions for transportation are permitted.

- Is the pipeline segment upstream of the central accumulation and/or treatment point?

  If the answer is "yes," the pipeline is a gathering line, and no deductions for transportation are permitted.

- Is the pipeline segment beyond the initial treatment point, central accumulation point, or measurement facilities?

  If the answer is "yes," the pipeline is not a gathering line and may be eligible for a transportation allowance.

- Is the pipeline segment a link in the continuous flow of marketable product to the point of delivery?

  If the answer is "yes," the pipeline is not a gathering line and may be eligible for a transportation allowance.

5.2 Limitations and Exceptions on Transportation Allowances

Transportation allowances are calculated on a selling arrangement basis and are limited to 50 percent of the value of the oil at the point of sale or value determination. Costs incurred for transportation under one selling arrangement may not be transferred to another selling arrangement or product. This limitation includes transportation factors, which cannot exceed 50 percent of the value of the oil without MMS approval. For example, if a barrel of oil is being sold for $15, then the transportation allowance is limited to $7.50/bbl ($15 x 50%).

If the lessee incurs transportation costs in excess of 50 percent of the value of oil under a selling arrangement, the lessee may request MMS approval of a transportation allowance deduction in excess of the limitation. MMS requires the lessee to submit an application for exception to the limitation annually (see "Exception to 50-percent limitation" on p. 5-57 for more information).

MMS makes a determination based on the merits of the case. However, for royalty purposes, under no circumstances shall the value of oil under any selling arrangement be reduced to zero. The lessee may not claim a transportation allowance that is greater than 99 percent of the value of oil under any selling arrangement.

The lessee may not report allowances in excess of the 50-percent limit on Form MMS-2014 until MMS approves the lessee's application for exception.

5.3 Allowable and Nonallowable Oil Transportation Costs

Transportation allowances are granted for reasonable, actual costs incurred for and directly related to transportation of marketable oil by pipeline, truck, barge, or other conveyance to a sales point or value determination point off the lease.

Acceptable transportation costs include:

- Pipeline costs or fees;
- Barging or trucking costs or fees, including loading or unloading costs;
- Rail car and tanker costs; and
- Costs for reseparation of condensate (if those costs are related to transportation of condensate through a gas stream after initial separation).

Terminal charges are allowed only to the extent that they cover the costs of loading and/or unloading oil into or from a vessel, vehicle, or similar conveyance.

5.3.1 Pipeline losses

Pipeline losses are actual or theoretical reductions in the volume of oil that travels through a pipeline. Pipeline losses are the result of either real, physical losses or errors in the measurement of the oil.

The lessee may incur the cost of a pipeline loss either by a reduction in the volume of oil (which results in lower gross proceeds received) or by a reduction in the value of oil on which the lessee received payment.

Allowable Costs. Under an arm's-length contract, if the lessee incurs an out-of-pocket expense for a line loss beyond the point of royalty settlement (a fuel charge), MMS may accept the value of the loss as an appropriate transportation cost. If the lessee is charged an actual reduction in the volume of oil delivered to the transporter, the lessee must convert the volume into a dollar amount. Royalty is always due on 100 percent of the volume measured at the approved point of royalty settlement.

For example, assume a lessee transports 4,000 bbl of oil valued at \$20/bbl. The lessee is charged 2 percent of the total volume for transportation, under an arm's-length contract or as part of a tariff approved by FERC or the State. The 2-percent volume reduction is converted to a dollar amount as follows:

$$\text{total volume transported} \times \text{volume reduction charge} \times \text{value per bbl} = \text{transportation costs}$$

$$4{,}000 \text{ bbl} \times 0.02 \times \$20/\text{bbl} = \$1{,}600$$

Nonallowable Costs. For non-arm's-length contracts or no-contract situations, actual or theoretical losses (based on volume or value) are not allowable transportation costs. However, these costs are allowable if they are based on a FERC- or State-approved tariff.

5.3.2 Arm's-length costs

MMS allows a deduction for the reasonable, actual transportation costs incurred by the lessee under an arm's-length contract. If a question arises as to the legitimacy of an arm's-length contract, the lessee has the burden of demonstrating that its contract is arm's-length under MMS standards. The criteria defining an arm's-length contract are provided in Chapter 4, "Gas Valuation."

Allowable Costs. Costs directly related to the actual transportation of oil are allowable costs.

For example, an arm's-length contract states that the transportation charge is \$0.75/bbl and the lessee pays that amount as an out-of-pocket expense. The lessee claims \$0.75/bbl as a transportation deduction.

Nonallowable Costs. Costs not directly related to the actual transportation of oil are nonallowable costs. The lessee may not claim a transportation allowance that is greater than the consideration actually transferred, either directly or indirectly, from the lessee to the transporter, regardless of what costs or fees are reflected in the arm's-length contract. If the contract lists more costs than the lessee actually pays, only that portion the lessee pays is eligible for a transportation allowance.

For example, an arm's-length contract states that the transportation charge is $1/bbl; however, the lessee pays only $0.50/bbl as an out-of-pocket expense. The lessee claims $0.50/bbl as a transportation deduction.

5.3.3 Non-arm's-length costs

If the lessee transports its oil through its own transportation system (a no-contract situation) or through its affiliate's transportation system (a non-arm's-length contract situation), transportation costs are divided into two categories:

1. Costs associated with capital investment, and

2. Costs associated with operations, maintenance, and overhead, collectively referred to as operating and maintenance costs.

MMS may request copies of invoices to verify capital costs and operating and maintenance costs claimed by the lessee.

5.3.3.1 Capital costs

Allowable Costs. Depreciable fixed assets (including costs of delivery and installation of capital equipment) that are an integral part of the transportation system are allowable capital costs (30 CFR 206.105(b)(2) and 30 CFR 206.55(b)(2)). The following capital items are allowable costs:

- Garages and warehouses
- Rail haulage equipment including rail spurs
- Trucks
- Barges
- Pipeline compressors and pumps on the transportation system
- Roads associated with the transportation system

Nonallowable Costs. The following costs are nonallowable deductions:

- Nondepreciable property such as land.

- Costs incidental to marketing; for example, on-lease and other nonallowable compressors, separators, dehydrators, and heaters/treaters.

- Schools, hospitals, roads, sewers, and other capital improvements or equipment not an integral part of the transportation facility.

- The capital costs associated with the preparation of an environmental impact statement. (However, capital costs for environmental equipment that is an integral part of the transportation facility are allowable.)

5.3.3.2 Operating and maintenance costs

Allowable Costs. Nondepreciable costs that are directly attributable and allocable to the operation and maintenance of a transportation facility/segment are allowable costs. These costs include:

- Salaries and wages paid to employees and supervisors while engaged in the operation and maintenance of transportation equipment and facilities.

- Fuel and utility costs directly related to transporting oil.

- Chemicals (including rust preventives and thinning agents) and lubricants used for the protection or cleaning of transportation facilities.

- Repairs, labor, materials, and supplies directly related to transportation equipment and facilities.

- Port and toll fees, insurance, ad valorem property taxes, and payroll taxes. (Federal and State income taxes are not allowable deductions.)

- Arm's-length rental, leasing, or contract service costs for equipment, facilities, onsite installation, or maintenance of equipment and facilities.

- General administrative overhead costs (salaries, telephone service, employee benefits, vehicle expenses, office supplies, etc.) directly attributable and allocable to the operation and maintenance of the transportation system. The lessee should maintain records to support all overhead costs included in an oil transportation allowance.

The total of these costs is limited to those reasonable expenditures directly attributable and allocable to the operation and maintenance of transportation equipment and facilities.

Nonallowable Costs. Costs that are not directly attributable and allocable to the transportation of oil are nonallowable costs. These costs include:

- Costs incidental to marketing; for example, on-lease compression, separation, dehydration, heating, treatment, metering, and water removal.
- Theoretical or actual line losses under a **non-arm's-length** or **no-contract** situation (see "Pipeline losses" on p. 5-7).
- Federal and State income taxes, production taxes, royalty payments, or fees (such as State and Indian severance taxes).
- Costs for services that the lessee is obligated to perform at no cost to the Federal Government or Indian lessor (such as costs associated with the construction of schools, hospitals, roads, and sewers).

5.4 Allocation of Costs

If oil transportation costs cannot be determined from the arm's-length contract, non-arm's-length contract, or no-contract situation, the total transportation costs must be allocated among all products in a consistent and equitable manner. The lessee must propose a cost allocation method to MMS and submit all data relevant to its proposal. The lessee may use its proposed allocation method until MMS issues its determination. The initial proposal must be submitted within 3 months of the last day of the month for which the lessee first deducts a transportation allowance. MMS will approve the method unless MMS determines that the method is not consistent with the purposes of the regulations.

Non-Royalty-Bearing Products. The lessee is not permitted to deduct the costs of transporting non-royalty-bearing products without MMS approval (30 CFR §§ 206.105(a)(2)(i), 206.55(a)(2)(i), 206.105(b)(3)(i), and 206.55(b)(3)(i)). In computing a transportation allowance for a gaseous and/or liquid stream that contains both royalty-bearing and non-royalty-bearing products, only the costs associated with transporting the royalty-bearing portion of the stream are deductible.

5.4.1 Liquid streams

If an oil transportation system contains other liquid products in addition to oil, the cost to transport each product is determined separately and allocated to each product for royalty valuation and reporting purposes. The requirements for allocating transportation costs are the same for **arm's-length** (30 CFR 206.105(a)(2)(i) and 30 CFR 206.55(a)(2)(i)) and **non-arm's-length** contracts and **no-contract** situations (30 CFR 206.105(b)(3)(i) and 30 CFR 206.55(b)(3)(i)). The cost allocated to each product must be based on the ratio of the volume of that product to the total volume of all products (excluding waste). The allocation is based on actual contract costs.

In computing the cost allocated to each product, the lessee must determine if each product is:

- Royalty-bearing,
- Non-royalty-bearing, or
- Waste.

NOTE

Transportation costs for a liquid stream are allocated only to the royalty-bearing and non-royalty-bearing products. For allocation purposes, a waste product is considered neither royalty-bearing nor non-royalty-bearing. Therefore, the waste product volume is excluded from the cost allocation.

For example, assume the lessee contracts to transport 100 bbl of liquid. The lessee is charged $1/bbl for transportation. The stream consists of

50 bbl of oil, 25 bbl of water, and 25 bbl of a non-royalty-bearing product. Determine the oil transportation allowance as follows:

STEP 1. Compute the total allowable costs incurred under the contract.

$$\$1/\text{bbl} \times 100 \text{ bbl} = \$100$$

STEP 2. Compute the volume of each royalty-bearing and non-royalty-bearing product and the total volume. (The 25 bbl of waste [water] is excluded.)

Royalty-bearing product (oil): 50 bbl
Non-royalty-bearing product: 25 bbl

$$50 \text{ bbl} + 25 \text{ bbl} = 75 \text{ bbl}$$

STEP 3. Compute the cost allocated to each product by multiplying the total cost by the ratio of the volume of each royalty-bearing and non-royalty-bearing product to the total volume of these products.

Royalty-bearing product (oil):

$$\frac{\$100 \times 50 \text{ bbl}}{75 \text{ bbl}} = \$66.666667$$

Non-royalty-bearing product:

$$\frac{\$100 \times 25 \text{ bbl}}{75 \text{ bbl}} = \$33.333333$$

STEP 4. Compute the oil transportation allowance by dividing the total cost allocated to oil by the total volume of oil.

$$\frac{\$66.666667}{50 \text{ bbl}} = \$1.333333/\text{bbl}$$

5.4.2 Liquid and gaseous streams

If an oil transportation system contains both liquid and gaseous products, the cost to transport each product is determined separately and allocated to each product for royalty valuation and reporting purposes. For an **arm's-length** contract, if the lessee can determine from the contract the transportation costs attributable to each product, the lessee should use those actual costs (30 CFR 206.105(a)(3) and 30 CFR 206.55(a)(3)). Otherwise, the requirements for allocating transportation costs are the same for arm's-length and **non-arm's-length** contracts and **no-contract** situations (30 CFR 206.105(b)(4) and 30 CFR 206.55(b)(4)).

For arm's-length contracts where costs cannot be determined from the contract and for non-arm's-length contracts and no-contract situations, the lessee must propose an allocation procedure to MMS. The proposed method should be based on the ratio of the volume of each product to the total volume of all products excluding waste.

The lessee may use its proposed allocation method to calculate an allowance until MMS accepts or rejects the proposed method. In its proposal, the lessee must explain its method and submit all available supporting data. The initial proposal must be submitted within 3 months after the last day of the month for which the lessee requests the allowance unless MMS approves a longer period. Based on the information submitted and other information MMS considers pertinent, MMS will accept or reject the lessee's calculated oil transportation allowance.

In computing the cost allocated to each product, the lessee must determine if each product is:

- Royalty-bearing,
- Non-royalty-bearing, or
- Waste.

NOTE

Transportation costs for a liquid and gaseous stream are allocated only to the royalty-bearing and non-royalty-bearing products. For allocation purposes, a waste product is considered neither royalty-bearing nor non-royalty-bearing. Therefore, the waste product volume is excluded from the cost allocation.

For example, assume the lessee contracts to transport 1,000 million British thermal units (MMBtu) of residue gas and reinjects 10 bbl of condensate (oil) into the gas stream. The lessee is charged $0.30/MMBtu for transportation. The stream consists of 975 MMBtu of residue gas, 10 MMBtu of CO_2, and 15 MMBtu of helium. Assume that CO_2 is a waste product and helium is a non-royalty-bearing product.

Determine the oil transportation allowance as follows:

STEP 1. Convert the barrels of oil to MMBtu using a standard conversion factor of 5.825 MMBtu/bbl[1] (assuming 1,000 Btu/ft^3).

$$10 \text{ bbl} \times 5.825 \text{ MMBtu/bbl} = 58.25 \text{ MMBtu}$$

STEP 2. Compute the total allowable costs incurred under the contract:

$$(58.25 \text{ MMBtu} + 1{,}000 \text{ MMBtu}) \times \$0.30/\text{MMBtu} = \$317.475$$

STEP 3. Compute the volume of each royalty-bearing and non-royalty-bearing product and the total volume. (The 10 MMBtu of waste [CO_2] is excluded.)

Royalty-bearing product (oil): 58.25 MMBtu
Royalty-bearing product (residue gas): 975 MMBtu
Non-royalty-bearing product (helium): 15 MMBtu

$$58.25 \text{ MMBtu} + 975 \text{ MMBtu} + 15 \text{ MMBtu} = 1{,}048.25$$

STEP 4. Compute the cost allocated to each product by multiplying the total cost by the ratio of the volume of each royalty-bearing and non-royalty-bearing product to the total volume of these products.

Royalty-bearing product (oil):

$$\frac{\$317.475 \times 58.25 \text{ MMBtu}}{1{,}048.25 \text{ MMBtu}} = \$17.641706$$

Royalty-bearing product (residue gas):

$$\frac{\$317.475 \times 975 \text{ MMBtu}}{1{,}048.25 \text{ MMBtu}} = \$295.290365$$

[1] Energy Information Administration, *Monthly Energy Review*, Table A2, Approximate Heat Content of Petroleum Products, June 1992.

Non-royalty-bearing product (helium):

$$\frac{\$317.475 \times 15\text{ MMBtu}}{1{,}048.25\text{ MMBtu}} = \$4.542929$$

STEP 5. Compute the oil transportation allowance by dividing the total cost allocated to oil by the total volume of oil. (The lessee would also compute the residue gas transportation allowance in the same way.)

$$\frac{\$17.641706}{58.25\text{ MMBtu}} = \$0.302862$$

STEP 6. Convert the computed allowance into a per-barrel cost.

$$\$0.302862/\text{MMBtu} \times 5.825 = \$1.764171/\text{bbl}$$

5.4.3 Allocation based on product value

As an alternative to cost allocation on a volumetric basis, the lessee may propose a cost allocation method to MMS based on values of the products transported. MMS will approve the lessee's proposed method unless MMS determines that the method is not consistent with the purposes of the transportation regulations (30 CFR §§ 206.105(a)(2)(ii), 206.55(a)(2)(ii), 206.105(b)(3)(ii), and 206.55(b)(3)(ii)).

For example, assume the lessee contracts to transport 1,000 MMBtu of gas and reinjects 10 bbl of condensate (oil) into the gas stream. The lessee is charged $0.30/MMBtu for transportation. The stream consists of 975 MMBtu of gas and 25 MMBtu of CO_2. Assume that CO_2 is a waste product. Oil value is $15/bbl; gas value is $3/MMBtu. Determine the oil transportation allowance as follows:

STEP 1. Convert the barrels of oil to MMBtu using a standard conversion factor of 5.825 MMBtu/bbl[2] (assuming 1,000 Btu/ft^3).

$$10\text{ bbl} \times 5.825\text{ MMBtu/bbl} = 58.25\text{ MMBtu}$$

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[2] Energy Information Administration, *Monthly Energy Review*, Table A2, Approximate Heat Content of Petroleum Products, June 1992.

STEP 2. Compute the total allowable costs incurred under the contract:

$$(58.25 \text{ MMBtu} + 1{,}000 \text{ MMBtu}) \times \$0.30/\text{MMBtu} = \$317.475$$

STEP 3. Compute the value of each product and the total product value:

Oil value: $10 \text{ bbl} \times \$15/\text{bbl} = \$150$

Gas value: $975 \text{ MMBtu} \times \$3/\text{MMBtu} = \$2{,}925$

Total value: $\$150 + \$2{,}925 = \$3{,}075$

STEP 4. Compute the costs allocated to each product by multiplying the total cost by the ratio of the value of each product to the total value of all products:

Oil: $$\frac{\$317.475 \times \$150}{\$3{,}075} = \$15.486585$$

Gas: $$\frac{\$317.475 \times \$2{,}925}{\$3{,}075} = \$301.988415$$

STEP 5. Compute the oil transportation allowance by dividing the total cost allocated to oil by the total volume of oil. (The lessee would also compute the gas transportation allowance in the same way.)

$$\frac{\$15.486585}{10 \text{ bbl}} = \$1.548659$$

5.5 Units of Measurement

Where the lessee's payments for transportation under an arm's-length contract are not on a dollar-per-unit basis, the lessee must convert whatever consideration is paid to a dollar amount (30 CFR 206.105(a)(4) and 30 CFR 206.55(a)(4)).

For example, assume the lessee transports 10,000 bbl of oil valued at $15/bbl. The lessee is charged 5 percent of the total volume for transportation.

The 5-percent transportation charge is converted to a dollar amount as follows:

STEP 1. Determine the total transportation cost.

$$\text{total volume transported} \times \text{transportation charge} \times \text{value per barrel} = \text{transportation cost}$$

$$10{,}000\ \text{bbl} \times 0.05 \times \$15/\text{bbl} = \$7{,}500$$

STEP 2. Determine the transportation rate per unit.

$$\frac{\text{total transportation cost}}{\text{total volume transported}} = \text{transportation rate per bbl}$$

$$\frac{\$7{,}500}{10{,}000} = \$0.75/\text{bbl}$$

5.6 Reporting and Recordkeeping Requirements

This section describes the reporting and recordkeeping requirements MMS has established for oil transportation allowances. Oil transportation allowances are reported as a separate line item on Form MMS-2014 using TC 11 unless MMS approves a different reporting procedure.

After a PIF is submitted to MMS designating an individual as a royalty payor (not a rental payor), MMS preprints a Model Form MMS-2014. The Model form is sent monthly to the designated individual. The preprinted Model Form MMS-2014 contains allowance lines if an allowance form has been filed with MMS. If the allowance lines are not preprinted on the lessee's Model Form MMS-2014 then either:

- An appropriate allowance form has not been filed,
- Erroneous data were reported on the allowance form submitted to MMS, or

- The Model Form MMS-2014 was printed prior to MMS receiving the allowance form.

In the months in which the allowance lines do not preprint on Model Form MMS-2014, the lessee needs to include these lines manually on its Model Form MMS-2014 before submitting it to MMS. If the allowance form is incorrect, the lessee should contact the Compliance Verification Division. (See "Important Addresses and Phone Numbers" on p. 1-5.)

No prior approval is required to deduct an oil transportation allowance, provided the allowance does not exceed 50 percent of the value of the oil. However, an Indian lessee is required to file the appropriate forms before deducting any estimated or actual allowance on Form MMS-2014.

An oil transportation allowance may be claimed retroactively on Indian leases for a period of not more than 3 months prior to the first day of the month that Form MMS-4110 is filed with MMS unless MMS approves a longer period upon a showing of good cause by the lessee. The elements that constitute good cause are determined on a case-by-case basis (see "Exception to 3-month retroactive limitation" on p. 5-58 for more information).

The following forms are used to report oil transportation allowances for Indian leases:

Form	**Title**
Form MMS-4110	
Page 1	Oil Transportation Allowance Report
Schedule 1	Oil Transportation Facility Summary Report
Schedule 1A	Non-Arm's-Length Transportation System/Segment Operations, Maintenance, and Overhead Expenditures
Supplemental Schedule 1A	Non-Arm's-Length Transportation System/Segment Operations, Maintenance, and Overhead Expenditures (continuation sheet)
Schedule 1B	Non-Arm's-Length Transportation System/Segment Depreciation and Capital Expenditure Summary

5.6.1 Arm's-length transportation contracts

For transportation costs incurred by the lessee under an arm's-length contract, the transportation allowance is the reasonable, actual costs incurred by the lessee for transporting oil under that contract.

The lessee is obligated to market oil for the mutual benefit of the lessee and the lessor. MMS expects a lessee to be prudent in negotiating a transportation contract that reflects only reasonable, actual expenses necessary to transport oil to the nearest sales point. If MMS determines that the consideration paid under an arm's-length transportation contract does not reflect reasonable value because of misconduct or breach of duty by the lessee to market the production for the mutual benefit of the lessee and the lessor or if the contract reflects more than the total consideration, MMS requires the lessee to determine the transportation costs based on the non-arm's-length or no-contract criteria (30 CFR §§ 206.105(a)(1)(iii), 206.55(a)(1)(iii), 206.105(a)(1)(ii), and 206.55(a)(1)(ii)).

The lessee has the burden of demonstrating that its contract is arm's-length. If necessary, MMS may require a lessee to submit its arm's-length transportation contracts, production and operating agreements, and related documents to demonstrate that the consideration paid reflects reasonable value. These documents must be submitted within a reasonable time as determined by MMS.

If a lessee has arm's-length contracts involving spot sales, variable rates, or any other situation where the allowance rate may vary from month to month, the lessee should report its actual costs every month on Form MMS-2014. The lessee should report a volume-weighted-average allowance rate on Form MMS-4110 for the applicable reporting period and indicate the type of contract (see "Instructions for Completing Form MMS-4110 for Arm's-Length Contracts—Indian Leases Only" on p. 5-24).

For example, assume the lessee has 12 spot sales contracts for January 1 through December 31, 1990.

STEP 1. For each contract, compute the transportation cost for the period by multiplying the transportation charge by the volume transported.

Sales month/year	Transportation charge ($/bbl)	Volume transported (bbl)	Total contract cost
1/90	$ 2.60	100	$ 260.00
2/90	2.10	75	157.50
3/90	3.50	132	462.00
4/90	3.30	612	2,019.60
5/90	3.30	123	221.40
6/90	1.80	121	217.80
7/90	2.30	967	2,224.10
8/90	1.90	118	224.20
9/90	2.60	824	2,142.40
10/90	2.60	845	2,197.00
11/90	2.50	801	2,002.50
12/90	2.70	993	2,681.10
	Total	5,711	$14,809.60

STEP 2. Compute the volume-weighted-average allowance rate for the year by summing the total contract costs and dividing by the total volume transported under all contracts.

$$\frac{\$14{,}809.60}{5{,}711\ \text{bbl}} = \$2.593171/\text{bbl}$$

5.6.2 Non-arm's-length transportation contracts or no-contract situations

Transportation allowances for non-arm's-length contracts or no-contract situations are based on the lessee's actual costs for transporting lease oil during the reporting period. The lessee's actual costs include operating, maintenance, and overhead expenses (combined operating and maintenance costs) and **either**:

- Depreciation and a return on undepreciated capital investment (depreciation method); or
- A return on the initial capital invested in the transportation system (return-on-investment method).

Transportation allowances for facilities placed into service before March 1, 1988, can be computed by using only the depreciation method. Transportation allowances for facilities placed into service on or after March 1, 1988, can be computed by using either the depreciation method or the return-on-investment method. After the lessee has elected to use either method to compute the allowance, the lessee may not later change to the other method without MMS approval.

The rate of return used in either the depreciation method or the return-on-investment method is the monthly average industrial BBB bond rate published in *Standard and Poor's Bond Guide* for the first month of the reporting period for which the allowance applies. This rate remains effective during the reporting period and is redetermined at the beginning of each subsequent reporting period.

MMS grants an exception from the requirement that the lessee compute actual costs for non-arm's-length contracts or no-contract situations only if the lessee has a tariff for the transportation system approved by FERC (for both Federal and Indian leases) or a State regulatory agency (for Federal leases) (see "Exception to compute actual costs" on p. 5-58 for more information).

The lessee must submit a request for the exception annually. If MMS approves the request, the lessee should follow the arm's-length reporting requirements.

5.6.2.1 Depreciation

If the lessee uses the depreciation method, depreciation may be computed by either:

- Straight-line depreciation based on the reasonable life of the equipment or the reasonable life of the reserves, or
- Unit-of-production method.

After the lessee has elected one method to compute depreciation, the lessee may not later change to the other method without MMS approval. In addition, a change in ownership of the transportation facility does not alter the depreciation schedule established by the original lessee; a transportation facility or equipment can be depreciated only once. Equipment may not be depreciated below a reasonable salvage value without MMS approval.

If the lessee uses the return-on-investment method, capital costs are computed by multiplying the allowable initial capital invested in the transportation system by the rate of return. Depreciation is not used with this method.

Allowable capital costs are those costs for depreciable fixed assets that are an integral part of the transportation system, including costs of delivery and installation. The allowable and nonallowable capital costs are described in detail in "Capital costs" on page 5-9.

5.6.2.2 Throughput

Transportation allowances are based on the total volumes transported through the transportation system during the reporting period.

5.6.2.3 Transportation system segments

A **transportation facility** is a physical system associated with the transportation of oil from the lease to a point of disposition remote from the lease. Where transportation systems consist of segments, cost rates are computed for each segment.

A **transportation segment** is any mode of transportation from one point to another for which the lessee can associate unique, identifiable costs. A transportation segment may be part of the total transportation facility, such as from one tie-in location to another on the pipeline, or may constitute the entire facility. Examples of a transportation segment would be an origin-to-destination pipeline owned by the lessee or truck haulage over specific routes where the equipment is owned by the lessee. An example of a multisegment transportation system would be a pipeline bringing oil to a transfer point and rail or truck haulage transporting oil from the transfer point to a remote point of sale.

5.7 Instructions for Completing Form MMS-4110 for Arm's-Length Contracts—Indian Leases Only

Lessees of Indian leases are required to file for an allowance prior to claiming that allowance on Form MMS-2014. The following sections provide instructions for completing Form MMS-4110 for arm's-length contracts.

For arm's-length contracts, the lessee must complete Page 1 and Schedule 1 of Form MMS-4110.

NOTE

Fill out the forms in reverse order. For example, prepare Schedule 1 before filling out Page 1.

In the following instructions, wherever a dashed horizontal line occurs in an example, a portion of the form has been omitted to save space.

5.7.1 Oil Transportation Allowance Report (Page 1), Form MMS-4110 (arm's-length)

The Oil Transportation Allowance Report (Page 1), Form MMS-4110, (fig. 5-1), is used to report the actual royalty allowance amounts claimed during the prior reporting period and to estimate the royalty allowance amount for the current reporting period. Reporting is by accounting identification (AID) number (13 digits), product code (2 digits), and selling arrangement (3 digits). Page 1 acts as a summary sheet for information on Schedule 1 of Form MMS-4110.

Complete Page 1 of Form MMS-4110 by following the instructions presented below. Any deviation from these instructions may result in the lessee incurring either a payback bill or an interest bill.

NOTE

The examples provided do not necessarily relate directly to one another.

U.S. DEPARTMENT OF THE INTERIOR
Minerals Management Service
Royalty Management Program

OIL TRANSPORTATION ALLOWANCE REPORT

OMB NO. 1010 - 0061
Expires May 31, 20XX

FOR MMS USE ONLY:

1 PAYOR NAME ____________________

ADDRESS ____________________

CITY ____________ STATE ________ ZIP ________

2 PAYOR CODE

4 FEDERAL or INDIAN

5 REPORT TYPE

6 REPORTING PERIOD ______ 19 to ______ 19

3 FOR PAYOR USE ONLY:

FOR ILLUSTRATION ONLY

7	8 ACCOUNTING IDENTIFICATION (AID) NUMBER	9 PRODUCT CODE	10 SELLING ARRANGEMENT CODE	11 ARM'S-LENGTH/ PAYOR-OWNED INDICATOR	12 PRIOR PERIOD ACTUAL DATA a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT	13 CURRENT PERIOD ESTIMATED DATA a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT
1										
2										
3										
4										
5										
6										
7										
8										
9										
10										
11					Expires May 31, 20XX					
12	PAGE TOTAL					xxxxxxxxxxxx			xxxxxxxxxxxx	
13	REPORT TOTAL (LAST PAGE ONLY)					xxxxxxxxxxxx			xxxxxxxxxxxx	

IF MORE LINES ARE NEEDED, ATTACH ADDITIONAL PAGES OF FORM MMS-4110

I have read and examined the statements in this report and, to the best of my knowledge, they are accurate and complete.

NAME (FIRST, MIDDLE INITIAL, LAST) (typed or printed) 14 DATE:

AUTHORIZED SIGNATURE: DATE:

NAME OF PREPARER: TELEPHONE NUMBER:

WARNING: This is to inform you that failure to report accurately and timely in accordance with the statutes, regulations, or terms of the lease, permit, or contract may result in late payment charges, civil penalties, or liquidated damages being assessed without further notification. Intentional false or inaccurate reporting is subject to criminal prosecution in accordance with applicable Federal law(s).

THIS INFORMATION SHOULD BE CONSIDERED (Please check one) ☐ PROPRIETARY ☐ NONPROPRIETARY 15

FORM MMS-4110 (2/96)

The Paperwork Reduction Act of 1980 (44 U.S.C. 3501 et seq.) requires MMS to inform you that this information is being collected for the purpose of managing its oil transportation allowance program.

FIGURE 5-1. Oil Transportation Allowance Report (Page 1), Form MMS-4110

STEP 1. In field 1, enter the payor name and address used to report royalties and transportation deductions on Form MMS-2014.

STEP 2. In field 2, enter the same payor code as used on Form MMS-2014.

Field 3 is reserved for payor comment.

STEP 3. In field 4, check the Indian box to indicate the type of lease(s) covered by this report.

STEP 4. In field 5, enter the report type indicator. Form MMS-4110 is classified into three report types, described as follows:

Report type 1 is used for initial reporting under the new regulations, reporting on newly acquired lease(s), or reporting estimates only. No prior period actual data are reported in column 12. Only the current period estimated data are reported in column 13.

U.S. DEPARTMENT OF THE INTERIOR
Minerals Management Service
Royalty Management Program

OIL TRANSPORTATION ALLOWANCE REPORT

OMB NO. 1010 - 0061
Expires May 31, 20XX

FOR MMS USE ONLY:

1 PAYOR NAME Bob Henry Oil Company
ADDRESS 101 Broadway
CITY Lakewood STATE CO ZIP 80228

2 PAYOR CODE 12345
4 FEDERAL ☐ or INDIAN ☒
5 REPORT TYPE 1
6 REPORTING PERIOD 01/01 19 89 to 12/13 19 89

3 FOR PAYOR USE ONLY:

7	8 ACCOUNTING IDENTIFICATION (AID) NUMBER	9 PRODUCT CODE	10 SELLING ARRANGEMENT CODE	11 ARM'S-LENGTH/ PAYOR-OWNED INDICATOR	12 PRIOR PERIOD ACTUAL DATA a ROYALTY QUANTITY	12 b ALLOWANCE RATE PER UNIT	12 c ROYALTY ALLOWANCE AMOUNT	13 CURRENT PERIOD ESTIMATED DATA a ROYALTY QUANTITY	13 b ALLOWANCE RATE PER UNIT	13 c ROYALTY ALLOWANCE AMOUNT
1	516-001234-0-001	01	001	5				450	1.531944	689
2										
3										

Report type 2 is a routine report used to report the prior period actual data and the current period estimated data. Column 12 must be filled in. If there will be no future production, leave column 13 blank (do not use zeros). If future production is anticipated, complete column 13 with current period estimated data.

STEP 4. ***(continued)***

If the payor reports current period estimated data in column 13, the automated system generates a reporting period beginning with the first day after the prior period actual data reporting period and continuing until the end of that calendar year.

U.S. DEPARTMENT OF THE INTERIOR
Minerals Management Service
Royalty Management Program

OIL TRANSPORTATION ALLOWANCE REPORT

OMB NO. 1010 - 0061
Expires May 31, 20XX

FOR MMS USE ONLY:
Received
3/25/91

1 PAYOR NAME Bob Henry Oil Company
ADDRESS 101 Broadway
CITY Lakewood STATE CO ZIP 80228

2 PAYOR CODE 12345
4 FEDERAL or INDIAN [X] INDIAN
5 REPORT TYPE 2
6 REPORTING PERIOD 01/01 19 89 to 12/31 19 89

3 FOR PAYOR USE ONLY:

7	8 ACCOUNTING IDENTIFICATION (AID) NUMBER	9 PRODUCT CODE	10 SELLING ARRANGEMENT CODE	11 ARM'S-LENGTH/ PAYOR-OWNED INDICATOR	12 PRIOR PERIOD ACTUAL DATA a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT	13 CURRENT PERIOD ESTIMATED DATA a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT
1	516-001234-0-001	01	001	5	450	1.531944	689	450	1.531944	689
2										
3										

Report type 3 is used to correct previously submitted reports and contains only one reporting period. Either column 12 or 13 must be completed, but not both. If correcting an initial report (report type 1), only one corrected Form MMS-4110 (report type 3) is required. If correcting a routine report (report type 2), two separate corrected reports (report type 3) are required: one to correct the prior period actual data in column 12 and one to correct the current period estimated data in column 13.

No minus signs are required to reverse the incorrect entry. However, if correcting the payor code, AID number, product code, or selling arrangement, place the correct data in the appropriate field(s) and indicate in field 3 (For Payor Use Only) the original filing date of the report.

STEP 4. ***(continued)***

NOTE

A payor code can be corrected only if it is one of the lessee's other valid codes. A lease number cannot be corrected. If a lease number was reported incorrectly, a new report type 1 or 2 must be submitted with the correct lease number. The revenue source, product code, and/or selling arrangement may be corrected.

To correct the prior period actual data, complete column 12 only. Use the period indicative of the prior period actual data as the reporting period.

U.S. DEPARTMENT OF THE INTERIOR
Minerals Management Service
Royalty Management Program

OIL TRANSPORTATION ALLOWANCE REPORT

OMB NO. 1010 - 0061
Expires May 31, 20XX

FOR MMS USE ONLY:

1 PAYOR NAME Bob Henry Oil Company
ADDRESS 101 Broadway
CITY Lakewood STATE CO ZIP 80228

2 PAYOR CODE 12345
4 FEDERAL [ ] or INDIAN [X]
5 REPORT TYPE 3
6 REPORTING PERIOD 01/01 1990 to 12/31 1990

3 FOR PAYOR USE ONLY: 3/25/91

7	8 ACCOUNTING IDENTIFICATION (AID) NUMBER	9 PRODUCT CODE	10 SELLING ARRANGEMENT CODE	11 ARM'S-LENGTH/ PAYOR-OWNED INDICATOR	12 PRIOR PERIOD ACTUAL DATA a ROYALTY QUANTITY	12 b ALLOWANCE RATE PER UNIT	12 c ROYALTY ALLOWANCE AMOUNT	13 CURRENT PERIOD ESTIMATED DATA a ROYALTY QUANTITY	13 b ALLOWANCE RATE PER UNIT	13 c ROYALTY ALLOWANCE AMOUNT
1	516-001234-0-001	01	001	5	450	1.531944	689			
2										
3										

To correct the current period estimated data, complete column 13 only. Use the period reflective of the current period estimated data as the reporting period shown in field 6.

STEP 4. *(continued)*

U.S. DEPARTMENT OF THE INTERIOR
Minerals Management Service
Royalty Management Program

OIL TRANSPORTATION ALLOWANCE REPORT

OMB NO. 1010 - 0061
Expires May 31, 20XX

FOR MMS USE ONLY:

1 PAYOR NAME Bob Henry Oil Company

ADDRESS 101 Broadway

CITY Lakewood STATE CO ZIP 80228

2 PAYOR CODE 12345

4 FEDERAL or INDIAN [X] INDIAN

5 REPORT TYPE 3

6 REPORTING PERIOD 01/01 19 90 to 12/31 19 90

3 FOR PAYOR USE ONLY: 3/25/91

7	8 ACCOUNTING IDENTIFICATION (AID) NUMBER	9 PRODUCT CODE	10 SELLING ARRANGEMENT CODE	11 ARM'S-LENGTH/ PAYOR-OWNED INDICATOR	12 PRIOR PERIOD ACTUAL DATA a ROYALTY QUANTITY	12 b ALLOWANCE RATE PER UNIT	12 c ROYALTY ALLOWANCE AMOUNT	13 CURRENT PERIOD ESTIMATED DATA a ROYALTY QUANTITY	13 b ALLOWANCE RATE PER UNIT	13 c ROYALTY ALLOWANCE AMOUNT
1	516-001234-0-001	01	001	5				450	1.531944	689
2										
3										

The next examples of Form MMS-4110 show an incorrect selling arrangement (report type 2) and the corrected reports (report type 3) required to correct the error. The same procedures are required to correct the revenue source and/or product code except that the correct data are reported in the corresponding AID number (column 8) and/or product code (column 9) columns.

In these examples, the lessee correctly reported selling arrangement code 001 on its Form MMS-2014 but inadvertently reported selling arrangement code 002 on its Form MMS-4110 (report type 2).

STEP 4. *(continued)*

U.S. DEPARTMENT OF THE INTERIOR
Minerals Management Service
Royalty Management Program

OIL TRANSPORTATION ALLOWANCE REPORT

OMB NO. 1010 - 0061
Expires May 31, 20XX

FOR MMS USE ONLY: Received 3/25/91

1 PAYOR NAME Bob Henry Oil Company
ADDRESS 101 Boardwalk
CITY Lakewood STATE CO ZIP 80228

2 PAYOR CODE 12345
4 FEDERAL or INDIAN [X] INDIAN
5 REPORT TYPE 2
6 REPORTING PERIOD 01/01 19 90 to 12/31 19 90

3 FOR PAYOR USE ONLY:

7	8 ACCOUNTING IDENTIFICATION (AID) NUMBER	9 PRODUCT CODE	10 SELLING ARRANGEMENT CODE	11 ARM'S-LENGTH/ PAYOR-OWNED INDICATOR	12 PRIOR PERIOD ACTUAL DATA a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT	13 CURRENT PERIOD ESTIMATED DATA a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT
1	516-001234-0-001	01	002	5	450	1.531944	689	450	1.531944	689
2										
3										

The lessee then submits two separate corrected Forms MMS-4110 (report type 3) to show the correct selling arrangement code of 001 for both the prior period actual data and the current period estimated data.

U.S. DEPARTMENT OF THE INTERIOR
Minerals Management Service
Royalty Management Program

OIL TRANSPORTATION ALLOWANCE REPORT

OMB NO. 1010 - 0061
Expires May 31, 20XX

FOR MMS USE ONLY:

1 PAYOR NAME Bob Henry Oil Company
ADDRESS 101 Boardwalk
CITY Lakewood STATE CO ZIP 80228

2 PAYOR CODE 12345
4 FEDERAL or INDIAN [X] INDIAN
5 REPORT TYPE 3
6 REPORTING PERIOD 01/01 19 90 to 12/31 19 90

3 FOR PAYOR USE ONLY: 3/25/91

7	8 ACCOUNTING IDENTIFICATION (AID) NUMBER	9 PRODUCT CODE	10 SELLING ARRANGEMENT CODE	11 ARM'S-LENGTH/ PAYOR-OWNED INDICATOR	12 PRIOR PERIOD ACTUAL DATA a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT	13 CURRENT PERIOD ESTIMATED DATA a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT
1	516-001234-0-001	01	001	5	450	1.531944	689			
2										
3										

STEP 4. ***(continued)***

U.S. DEPARTMENT OF THE INTERIOR
Minerals Management Service
Royalty Management Program

OIL TRANSPORTATION ALLOWANCE REPORT

OMB NO. 1010 - 0061
Expires May 31, 20XX

FOR MMS USE ONLY:

1 PAYOR NAME Bob Henry Oil Company

ADDRESS 101 Boardwalk

CITY Lakewood STATE CO ZIP 80228

2 PAYOR CODE 12345

4 FEDERAL or INDIAN [ ] FEDERAL [X] INDIAN

5 REPORT TYPE 3

6 REPORTING PERIOD 01/01 1991 to 12/31 1991

3 FOR PAYOR USE ONLY: 3/25/91

7	8 ACCOUNTING IDENTIFICATION (AID) NUMBER	9 PRODUCT CODE	10 SELLING ARRANGEMENT CODE	11 ARM'S-LENGTH/ PAYOR-OWNED INDICATOR	12 PRIOR PERIOD ACTUAL DATA a ROYALTY QUANTITY	12 b ALLOWANCE RATE PER UNIT	12 c ROYALTY ALLOWANCE AMOUNT	13 CURRENT PERIOD ESTIMATED DATA a ROYALTY QUANTITY	13 b ALLOWANCE RATE PER UNIT	13 c ROYALTY ALLOWANCE AMOUNT
1	516-001234-0-001	01	001	5				450	1.531944	689
2										
3										

STEP 5. In field 6, enter the reporting period for the report type selected as defined below.

NOTE

The reporting period must reflect the appropriate **sales** months.

Reporting period for a report type 1. A report type 1 indicates that the payor is reporting only the current period estimated data (column 13). Therefore, the reporting period reflects the current period estimated data.

STEP 5. *(continued)*

U.S. DEPARTMENT OF THE INTERIOR
Minerals Management Service
Royalty Management Program

OIL TRANSPORTATION ALLOWANCE REPORT

OMB NO. 1010 - 0061
Expires May 31, 20XX

FOR MMS USE ONLY:

1 PAYOR NAME Bob Henry Oil Company
ADDRESS 101 Broadway
CITY Lakewood STATE CO ZIP 80228

2 PAYOR CODE 12345
4 FEDERAL [ ] or INDIAN [X]
5 REPORT TYPE 1
6 REPORTING PERIOD 01/01 1989 to 12/31 1989

3 FOR PAYOR USE ONLY:

7	8 ACCOUNTING IDENTIFICATION (AID) NUMBER	9 PRODUCT CODE	10 SELLING ARRANGEMENT CODE	11 ARM'S-LENGTH/ PAYOR-OWNED INDICATOR	12 PRIOR PERIOD ACTUAL DATA a ROYALTY QUANTITY	12 b ALLOWANCE RATE PER UNIT	12 c ROYALTY ALLOWANCE AMOUNT	13 CURRENT PERIOD ESTIMATED DATA a ROYALTY QUANTITY	13 b ALLOWANCE RATE PER UNIT	13 c ROYALTY ALLOWANCE AMOUNT
1	516-001234-0-001	01	001	5				450	1.531944	689
2										
3										

Reporting period for a report type 2. A report type 2 indicates that the lessee is reporting prior period actual data (column 12). The lessee may or may not report current period estimated data (column 13) depending on the anticipation of production. Therefore, the reporting period on a report type 2 always reflects the prior period actual data (column 12). If the lessee reports current period estimated data (column 13), the automated system generates a reporting period beginning with the first day following the prior period actual data reporting period and continuing until the end of that calendar year.

STEP 5. ***(continued)***

U.S. DEPARTMENT OF THE INTERIOR
Minerals Management Service
Royalty Management Program

OIL TRANSPORTATION ALLOWANCE REPORT

OMB NO. 1010 - 0061
Expires May 31, 20XX

FOR MMS USE ONLY: Received 3/25/90

1 PAYOR NAME Bob Henry Oil Company
ADDRESS 101 Broadway
CITY Lakewood STATE CO ZIP 80228

2 PAYOR CODE 12345
4 FEDERAL or INDIAN: X (INDIAN)
5 REPORT TYPE 2
6 REPORTING PERIOD 01/01 19 89 to 12/31 19 89

3 FOR PAYOR USE ONLY:

7	8 ACCOUNTING IDENTIFICATION (AID) NUMBER	9 PRODUCT CODE	10 SELLING ARRANGEMENT CODE	11 ARM'S-LENGTH/ PAYOR-OWNED INDICATOR	12 PRIOR PERIOD ACTUAL DATA: a ROYALTY QUANTITY	12 b ALLOWANCE RATE PER UNIT	12 c ROYALTY ALLOWANCE AMOUNT	13 CURRENT PERIOD ESTIMATED DATA: a ROYALTY QUANTITY	13 b ALLOWANCE RATE PER UNIT	13 c ROYALTY ALLOWANCE AMOUNT
1	516-001234-0-001	01	001	5	450	1.531944	689	450	1.531944	689
2										
3										

Reporting period for a report type 3. A report type 3 indicates that the lessee is correcting previously submitted data for a specific reporting period. The lessee should fill out only column 12 to correct prior period actual data.

U.S. DEPARTMENT OF THE INTERIOR
Minerals Management Service
Royalty Management Program

OIL TRANSPORTATION ALLOWANCE REPORT

OMB NO. 1010 - 0061
Expires May 31, 20XX

FOR MMS USE ONLY:

1 PAYOR NAME Bob Henry Oil Company
ADDRESS 101 Broadway
CITY Lakewood STATE CO ZIP 80228

2 PAYOR CODE 12345
4 FEDERAL or INDIAN: X (INDIAN)
5 REPORT TYPE 3
6 REPORTING PERIOD 01/01 19 89 to 12/31 19 89

3 FOR PAYOR USE ONLY: 3/25/90

7	8 ACCOUNTING IDENTIFICATION (AID) NUMBER	9 PRODUCT CODE	10 SELLING ARRANGEMENT CODE	11 ARM'S-LENGTH/ PAYOR-OWNED INDICATOR	12 PRIOR PERIOD ACTUAL DATA: a ROYALTY QUANTITY	12 b ALLOWANCE RATE PER UNIT	12 c ROYALTY ALLOWANCE AMOUNT	13 CURRENT PERIOD ESTIMATED DATA: a ROYALTY QUANTITY	13 b ALLOWANCE RATE PER UNIT	13 c ROYALTY ALLOWANCE AMOUNT
1	516-001234-0-001	01	001	5	450	1.531944	689			
2										
3										

STEP 5. ***(continued)***

To correct the current period estimated data, fill out only column 13. Prior period actual data (column 12) must not be filled out.

U.S. DEPARTMENT OF THE INTERIOR
Minerals Management Service
Royalty Management Program

OIL TRANSPORTATION ALLOWANCE REPORT

OMB NO. 1010 - 0061
Expires May 31, 20XX

FOR MMS USE ONLY:

1 PAYOR NAME Bob Henry Oil Company
ADDRESS 101 Broadway
CITY Lakewood STATE CO ZIP 80228

2 PAYOR CODE 12345
4 FEDERAL or INDIAN [X]
5 REPORT TYPE [ ]
6 REPORTING PERIOD 01/01 1990 to 12/31 1990

3 FOR PAYOR USE ONLY: 3/25/90

7	8 ACCOUNTING IDENTIFICATION (AID) NUMBER	9 PRODUCT CODE	10 SELLING ARRANGEMENT CODE	11 ARM'S-LENGTH/ PAYOR-OWNED INDICATOR	12 PRIOR PERIOD ACTUAL DATA a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT	13 CURRENT PERIOD ESTIMATED DATA a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT
1	516-001234-0-001	01	001	5				450	1.531944	689.37
2										
3										

Column 7 represents the line count; that is, the number of allowances being reported.

STEP 6. In column 8, enter the same AID number as used on Form MMS-2014 for each allowance.

STEP 7. In column 9, enter the same product code as used on Form MMS-2014.

STEP 8. In column 10, enter the same selling arrangement code as used on Form MMS-2014.

STEP 9. In column 11, enter an arm's-length indicator as follows:

- Enter indicator **5** if transportation costs were incurred under a combination of arm's-length and non-arm's-length conditions.
- Enter indicator **6** if 100 percent of the transportation costs were incurred under arm's-length conditions.

STEP 10. In column 12, enter actual cost data for the reporting period.

NOTE If this is an initial report, a report for newly acquired leases, or a report for estimates (no actual data are reported), do not complete column 12. Instead, go to the instructions for column 13.

In column 12a, enter the total royalty quantity transported during the reporting period. Total royalty quantity is the sum of the monthly royalty quantities reported on Form MMS-2014, field 17, for a specific selling arrangement. Decimals are not required in this column.

In column 12b, enter the transportation allowance rate from Schedule 1 of Form MMS-4110, line 15. The rate in column 12b is computed to six decimals; however, zeros may be dropped.

NOTE The actual allowance rate cannot exceed 50 percent of the unit value of the oil unless MMS has approved a rate in excess of 50 percent.

In column 12c, enter the royalty allowance amount, computed by multiplying column 12a by 12b. Decimals are not required in column 12c.

STEP 11. In column 13, report an initial allowance under the new regulations, newly acquired leases, or estimates (no actual data are reported).

If an allowance was reported for the prior period, the transportation quantity or allowance rate may be the same as the actual quantity or allowance rate reported in column 12. If these are the same, enter the corresponding values from columns 12a, 12b, and 12c into columns 13a, 13b, and 13c, respectively. If the lessee believes the quantity or the rate for the current reporting period will differ from the prior reporting period, the estimates should be adjusted upward or downward.

STEP 11. ***(continued)***

Estimates should be as accurate as possible and should not exceed 50 percent of the expected royalty value without prior MMS approval. Overestimating on Form MMS-2014 will result in a royalty underpayment.

In column 13a, enter the total estimated royalty quantity to be transported during the current reporting period. Total royalty quantity is the sum of the monthly royalty quantities to be reported for a specific selling arrangement. Decimals are not required in this field.

In column 13b, for **fully arm's-length conditions**, enter the allowance rate specified in the arm's-length contract and shown on Schedule 1, line 15. For a **combination of arm's-length and non-arm's-length conditions**, use Schedules 1, 1A, and 1B (if appropriate) to estimate the allowance rate. The rate in column 13b is computed to six decimals; however, zeros may be dropped.

NOTE

The estimated allowance rate cannot exceed 50 percent of the value of the oil (unless MMS has approved a rate in excess of 50 percent).

In column 13c, enter the estimated royalty allowance amount, computed by multiplying column 13a by 13b. Decimals are not required in column 13c.

STEP 12. Enter page totals on line 12. If more than one Page 1 of Form MMS-4110 is submitted, subtotal the amount on line 12 for each page and enter the total once on line 13 of the last page.

STEP 13. In field 14, enter the name of the person authorized to sign the allowance form. Enter the current date. The authorized person must then sign and date the form. Enter the name and telephone number of the person who prepared the form.

STEP 14. In field 15, check the appropriate box to indicate whether the information is proprietary or nonproprietary.

5.7.2 Schedule 1—Oil Transportation Facility Summary Sheet, Form MMS-4110 (arm's-length)

Schedule 1—Oil Transportation Facility Summary Sheet, Form MMS-4110 (fig. 5-2), is used to accumulate segment costs and compute the royalty allowance rate for a transportation facility. A separate Schedule 1 must be completed for each unique AID number, product code, and selling arrangement combination. No allowance may be claimed if the facility is on the lease site.

Part A, Transporting Oil to a Remote Treatment Facility, is used to accumulate segment costs and to determine an allowance for transporting oil from the lease to a treatment facility off the lease. Part B, Transporting Oil to a Remote Sales Point, is used to accumulate segment costs and compute an allowance for transporting oil from either a lease or a separation facility to the nearest available marketplace or sales outlet off the lease.

The following instructions apply to both parts A and B. Lessees may need to complete part A, part B, or both. For simplicity, most of the following examples show only part B.

Complete Schedule 1 of Form MMS-4110 as follows:

STEP 1. In field 1, enter the same payor name, payor code, and address as used on Form MMS-2014.

STEP 2. In field 2, enter the same AID number/selling arrangement code as used on Form MMS-2014.

STEP 3. In field 3, enter the unique transportation facility name or identification (ID) number designated by the payor. If a transportation facility consists of only one segment, the segment name or ID number is the same as the facility name or ID number.

Enter the reporting period. The period will be the same as shown in field 6 on Page 1 of Form MMS-4110 (see fig. 5-1, p. 5-25).

U.S. DEPARTMENT OF THE INTERIOR
Minerals Management Service
Royalty Management Program

SCHEDULE 1 -- OIL TRANSPORTATION FACILITY SUMMARY SHEET

1 PAYOR NAME AND CODE ______ / ______

ADDRESS ______

CITY ______ STATE ______ ZIP ______

2 ACCOUNTING ID NUMBER: ______

SELLING ARRANGEMENT CODE: ______

3 FACILITY NAME/ID NUMBER: ______

PERIOD: 19 to 19

(a) Segment Name or Number (From / To)	(b) Mode of Transportation	(c) Arm's-Length/ Payor-Owned Indicator	(d) Arm's-Length Contract/ Payor-Owned Operating Costs	(e) Depreciation	(f) Rate of Return	(g) Undepreciated Capital Investment at Beginning of Year	(h) Return on Investment (f) x (g)	
A. TRANSPORTING OIL TO A REMOTE TREATMENT FACILITY.								
			$	$		$	$	3
								4
								5
								6
								7
		Totals	$	$			$	8

FOR ILLUSTRATION ONLY

Allowance rate = (lines 8d + 8e + 8h)/Volume of production transported from the lease to processing/treatment facility.

$ ______ ÷ ______ = $ ______ 9
Part A Total Cost — Part A Total Volume — Cost per Barrel

B. TRANSPORTING OIL TO A REMOTE SALES POINT.								
			$	$		$	$	10
								11
								12
		Totals	$	$			$	13

Allowance rate = (lines 13d + 13e + 13h)/Volume of products transported from the lease plant to the sales point.

$ ______ ÷ ______ = $ ______ 14
Part B Total Cost — Part B Total Volume — Cost per Barrel

Total Unit Allowance Rate = the sum of line 9h and 14h. The allowance rate cannot exceed 50 percent of the value of the product without prior MMS approval.

______ 15
Allowance Rate

THIS INFORMATION SHOULD BE CONSIDERED (Please check one) ☐ PROPRIETARY ☐ NONPROPRIETARY

FORM MMS-4110 SCHEDULE 1 (REV. 1/88)

FIGURE 5-2. Schedule 1—Oil Transportation Facility Summary Sheet, Form MMS-4110

STEP 4. In column a, Segment Name or Number, describe each segment of the transportation facility; for example, from the lease to Apache treatment facility.

STEP 5. In column b, Mode of Transportation, identify the mode of transportation under which costs are incurred; for example, pipeline, truck, rail, tanker, or barge.

STEP 6. In column c, Arm's-Length/Payor-Owned Indicator, record how facility/segment costs were incurred:

- Enter indicator **4** to denote payor-owned costs, which include non-arm's-length and no-contract situations.
- Enter indicator **6** to denote arm's-length contract costs.

NOTE When the indicator in column 11 (Arm's-Length/Payor-Owned Indicator) on Page 1 of Form MMS-4110 (fig. 5-1, p. 5-25) is a **5**, enter both **4** and **6** when completing column c on Schedule 1.

STEP 7. If transportation costs were incurred under an arm's-length contract, enter in column d (Arm's-Length Contract/Payor-Owned Operating Costs) the total costs incurred for the period. These costs are computed by multiplying the transportation rate by the volume transported at that contract rate. Without prior MMS approval, a transportation allowance may not be taken for non-royalty-bearing substances.

NOTE If two or more rates are applicable during the reporting period, the cost incurred under each rate must be computed and summed. For example, if the rates were \$0.10/bbl for 150 bbl and \$0.20/bbl for 100 bbl, the transportation costs would be:

$$(\$0.10/\text{bbl} \times 150\text{ bbl}) + (\$0.20/\text{bbl} \times 100\text{ bbl}) = \$35$$

Do **not** complete columns e through h for arm's-length costs.

STEP 8. Total column d and enter the amount(s) on line 8d and/or line 13d.

STEP 9. Enter the amount from line 8d and/or line 13d on line 9 and/or line 14 Total Cost.

Enter the total volume of production transported on line 9 and/or line 14 Total Volume. The total volume is the sum of sales quantities reported on Form MMS-2014 for the reporting period.

NOTE

Total throughput volume, excluding waste products that have no value, must be used.

STEP 10. Divide line 9 and/or line 14 Total Cost by line 9 and/or line 14 Total Volume to compute the cost per barrel. Compute this figure to six decimals (zeros may be dropped). Enter the amount on line 9h and/or line 14h (Cost per Barrel).

STEP 11. Add line 9h to line 14h to compute the total unit allowance rate. Enter this allowance on line 15.

STEP 12. Enter the allowance rate from line 15h to column 12b or 13b on Page 1 of Form MMS-4110 (fig. 5-1, p. 5-25).

STEP 13. Check the appropriate box to indicate whether the information is considered proprietary or nonproprietary.

5.8 Instructions for Completing Form MMS-4110 for Non-Arm's-Length Contracts or No-Contract Situations—Indian Leases Only

Lessees of Indian leases are required to file for an allowance prior to claiming that allowance on Form MMS-2014. The following sections provide instructions for completing Form MMS-4110 for non-arm's-length contracts or no-contract situations.

For non-arm's-length contracts or no-contract situations, the lessee must complete Page 1, Schedule 1, Schedule 1A, Supplemental Schedule 1A (if necessary), and Schedule 1B of Form MMS-4110.

NOTE Fill out the forms in reverse order. For example, prepare Schedule 1B before filling out Schedule 1.

5.8.1 Oil Transportation Allowance Report (Page 1), Form MMS-4110 (non-arm's-length or no-contract)

The Oil Transportation Allowance Report (Page 1), Form MMS-4110 (fig. 5-1, p. 5-25), is used to report the actual royalty allowance amounts claimed during the prior reporting period and to estimate the royalty allowance amount for the current reporting period. Reporting is by AID number (13 digits), product code (2 digits), and selling arrangement (3 digits).

Page 1 acts as a summary sheet for information on the schedules of Form MMS-4110. Refer to "Oil Transportation Allowance Report (Page 1), Form MMS-4110 (arm's-length)" on page 5-24 for full instructions for completing Page 1.

5.8.2 Schedule 1—Oil Transportation Facility Summary Sheet, Form MMS-4110 (non-arm's-length or no-contract)

Schedule 1—Oil Transportation Facility Summary Sheet, Form MMS-4110 (fig. 5-2, p. 5-38), is used to accumulate segment costs and compute the royalty allowance rate for a transportation facility. A separate Schedule 1 must be completed for each unique AID number, product code, and selling arrangement combination. No allowance may be claimed if the facility is on the lease site.

Part A, Transporting Oil to a Remote Treatment Facility, is used to accumulate segment costs and to determine an allowance for transporting oil from the lease to a processing facility off the lease. Part B, Transporting Oil to a Remote Sales Point, is used to accumulate segment costs and compute an allowance for transporting oil from either a lease or a separation facility to the nearest available marketplace or sales outlet off the lease.

Instructions for completing Schedule 1 (fig. 5-2, p. 5-38) of Form MMS-4110 follow.

STEP 1. In field 1, enter the same payor name, payor code, and address as used on Form MMS-2014.

STEP 2. In field 2, enter the same AID number/selling arrangement code as used on Form MMS-2014.

STEP 3. In field 3, enter the unique transportation facility name or ID number designated by the payor. If a transportation facility consists of only one segment, the segment name or ID number is the same as the facility name or ID number.

Enter the reporting period. The period will be the same as shown in field 6 on Page 1 of Form MMS-4110 (fig. 5-1, p. 5-25).

The following instructions apply to both parts A and B. Lessees may need to complete part A, part B, or both.

STEP 4. In column a, Segment Name or Number, describe each segment of the transportation facility; for example, from the lease to Apache treatment facility.

STEP 5. In column b, Mode of Transportation, identify the mode of transportation under which costs are incurred; for example, pipeline, truck, rail, tanker, or barge.

STEP 6. In column c, Arm's-Length/Payor-Owned Indicator, indicate how facility/segment costs were incurred:

- Enter indicator **4** to denote payor-owned costs, which include non-arm's-length and no-contract situations.
- Enter indicator **6** to denote arm's-length contract costs.

NOTE

When the indicator in column 11 (Arm's-Length/Payor-Owned Indicator) on Page 1 of Form MMS-4110 is a **5**, enter both **4** and **6** when completing column c on Schedule 1.

STEP 7. If transportation costs are incurred under other than arm's-length conditions, complete columns d, Arm's-Length Contract/Payor-owned Operating Costs, through h, Return on Investment. Use Schedule 1A to compute the operating, maintenance, and overhead expenditures. Enter the sum in column d on Schedule 1. A separate Schedule 1A must be completed for each individual segment.

STEP 8. In column e, Depreciation, enter depreciation costs for the reporting period. Schedule 1B (fig. 5-5, p. 5-52) must be used to determine depreciation costs.

NOTE

If a lessee is reporting for only 6 months of the year or the pipeline has been in service for only 6 months, the lessee must adjust the depreciation expense for the portion of the year in which the expense applies. For example, if the depreciable base is $2,000,000 and the estimated life is 20 years, the depreciation expense per year is $100,000. The depreciation expense for 6 months would be calculated as follows:

$$\text{Depreciation} = \$100{,}000 \times \frac{6}{12} = \$50{,}000$$

STEP 9. The rate of return is the industrial rate associated with Standard and Poor's BBB bond rating. In column f, Rate of Return, enter the monthly average rate as published in *Standard and Poor's Bond Guide* for the first month of the reporting period.

STEP 10. Using Schedule 1B (fig. 5-5, p. 5-52), sum the Salvage Value **and** the Undepreciated Capital Investment at Beginning of Year. The salvage value must be allocated proportionately to each segment by multiplying it by the Allocated to Segment amount from Schedule 1B, line 9. Enter this total in column g, Undepreciated Capital Investment at Beginning of Year, on Schedule 1. A separate Schedule 1B must be completed for each individual segment.

.

NOTE

The amount in column g **must** include salvage value; otherwise, the next calculation (return on investment) will be incorrect.

STEP 11. Calculate the return on investment by multiplying column f by column g. Enter the amount in column h.

NOTE

If a lessee is reporting for only 6 months of the year or the pipeline has been in service for only 6 months, the lessee must adjust for the partial year. For example, if the undepreciated investment at the beginning of the year is $250,000 and the industrial BBB bond rate is 10 percent, the return on investment (ROI) is calculated as follows:

$$\text{ROI} = \$250{,}000 \times \left(10\% \times \frac{6}{12}\right) = \$12{,}500$$

STEP 12. Total columns d, e, and h. Enter the amount(s) on lines 8d, 8e, and 8h for part A, and/or lines 13d, 13e, and 13h for part B.

STEP 13. Add the amounts in lines 8d, 8e, and 8h and/or lines 13d, 13e, and 13h, and enter the total on line 9 and/or line 14 Total Cost.

STEP 14. Enter the total volume of production transported on line 9 and/or line 14 Total Volume.

NOTE

Total throughput volume, excluding waste products that have no value, must be used.

STEP 15. Divide line 9 and/or line 14 Total Cost by line 9 and/or line 14 Total Volume to compute the allowance cost per barrel. Compute this figure to six decimals (zeros may be dropped). Enter the amount on line 9h and/or line 14h (Cost per Barrel).

STEP 16. Add line 9h to line 14h to compute the total unit allowance rate. Enter this rate on line 15.

STEP 17. Enter the allowance rate from line 15 on Page 1 of Form MMS-4110 (fig. 5-1, p. 5-25), in column 12b or 12c.

STEP 18. Check the appropriate box to indicate whether the information is proprietary or nonproprietary. Total throughput volume, excluding waste products that have no value, must be used.

5.8.3 Schedule 1A—Non-Arm's-Length Transportation System/Segment Operations, Maintenance, and Overhead Expenditures, Form MMS-4110 (non-arm's-length or no-contract)

Schedule 1A—Non-Arm's-Length Transportation System/Segment Operations, Maintenance, and Overhead Expenditures, Form MMS-4110 (fig. 5-3, p. 5-47), is used to record and summarize reasonable and actual operating, maintenance, and overhead costs for a non-arm's-length or no-contract transportation segment. A separate Schedule 1A must be completed for each segment in the transportation facility. For instance, if an oil transportation system has three segments, three Schedules 1A must be completed. The costs developed on Schedule(s) 1A are accumulated on Schedule 1 to compute the total operating costs for the facility.

Complete payor identification information fields of Schedule 1A as follows:

STEP 1. Enter the same payor name and code as used on Form MMS-2014.

STEP 2. Enter the same AID number and selling arrangement code as used on Form MMS-2014.

STEP 3. Enter the unique transportation facility name or ID number designated by the payor.

STEP 4. Enter the unique transportation segment name or ID number designated by the payor. If a transportation facility consists of only one segment, the segment name or ID number is the same as the facility name or ID number.

STEP 5. Enter the reporting period. The period must be the same as shown in field 6 on Page 1 of Form MMS-4110 (fig. 5-1, p. 5-25).

STEP 6. Enter a checkmark in the estimated costs checkbox if estimated costs are used for startup.

Instructions for computing operating, maintenance, and overhead costs are detailed below.

STEP 7. In parts A, Lessee's Operating Costs for System/Segment, and B, Lessee's Maintenance Costs, identify and list all operating and maintenance costs directly attributable to the transportation facility/segment during the reporting period. If more space is needed, attach a Supplemental Schedule 1A to identify or explain other cost items.

STEP 8. Sum lines 1 through 9 and enter the total operating costs on line 10.

STEP 9. Sum lines 11 through 15 and enter the total maintenance costs on line 16.

STEP 10. In part C, Lessee's Overhead Allocation, identify and list all overhead costs directly allocable and attributable to the operations and maintenance of the transportation facility/segment. If more space is needed, attach a Supplemental Schedule 1A.

STEP 11. Sum lines 17 through 19 and enter the total overhead expenditures directly allocable to the facility/segment on line 20.

STEP 12. Sum lines 10, 16, and 20, and enter the total operating and maintenance costs on line 21.

STEP 13. Enter the lease volume transported through this segment and the total throughput of this segment where indicated on line 22.

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SCHEDULE 1A— NON-ARM'S-LENGTH TRANSPORTATION SYSTEM/ SEGMENT OPERATIONS, MAINTENANCE, AND OVERHEAD EXPENDITURES

PAYOR IDENTIFICATION BLOCK
Payor Name and Code:
Accounting ID No:
Selling Arrangement Code:
Facility ID No:
Segment ID No:
Period: 19 to 19

☐ Estimated Costs - Check when estimating costs for system/segment start-up.

A.	Lessee's Operating Costs for System/Segment		
	Operations Supervision and Engineering	$	1
	Operations Labor		2
	Utilities		3
	Materials		4
	Ad Valorem Property Taxes		5
	Rent		6
	Supplies		7
	Other (specify). Attach Supplemental Schedule 1A		8
	as necessary		9
	Total Operating Costs -- Subtotal	$	10
B.	Lessee's Maintenance Costs		
	Maintenance Supervision	$	11
	Maintenance Labor		12
	Materials		13
	Other (specify). Attach Supplemental Schedule 1A		14
	as necessary		15
	Total Maintenance Costs -- Subtotal	$	16
C.	Lessee's Overhead Allocation (specify)		
		$	17
			18
	Other (specify) use Supplemental Schedule 1A		19
	Total Overhead Allocation	$	20
D.	Total Operating and Maintenance Costs (Line 10 + line 16 + line 20)	$	21
E.	Allocated to Segment Lease Volume ______ ÷ Total throughput ______	$	22
F.	Segment Allocated Operating, Maintenance, and Overhead Costs (Line 21 x line 22) Enter in column d, Schedule 1	$	23

FOR ILLUSTRATION ONLY

THIS INFORMATION SHOULD BE CONSIDERED (Please check one) ☐ PROPRIETARY ☐ NONPROPRIETARY

FORM MMS-4110 SCHEDULE 1A (REV. 1/88)

FIGURE 5-3. Schedule 1A—Non-Arm's-Length Transportation System/Segment Operations, Maintenance, and Overhead Expenditures, Form MMS-4110

NOTE

Use the total throughput quantity excluding waste products, which have no value. If there are multiple lessees on a lease, each lessee should enter only its portion of the lease volume and total pipeline throughput.

STEP 14. Divide the lease volume by the total throughput (on the first two fields on line 22), and enter the amount on line 22.

STEP 15. Multiply line 21 by line 22 to compute the allocated operating, maintenance, and overhead costs for the segment. Enter this amount on line 23.

STEP 16. Enter the amount from line 23 in column d of Schedule 1, part A or B, as applicable.

STEP 17. Check the appropriate box to indicate whether the information is proprietary or nonproprietary.

5.8.4 Supplemental Schedule 1A—Non-Arm's-Length Transportation System/Segment Operations, Maintenance, and Overhead Expenditures, Form MMS-4110 (non-arm's-length or no-contract)

Supplemental Schedule 1A—Non-Arm's-Length Transportation System/Segment Operations, Maintenance, and Overhead Expenditures, Form MMS-4110 (fig. 5-4), is used to identify and document operating, maintenance, and overhead expenditures listed on Schedule 1A under the Other Expenditure categories, lines 8 and 9, 14 and 15, and 19. The Supplemental Schedule 1A is a continuation sheet for data that cannot be shown on Schedule 1A because of space limitations.

A separate Supplemental Schedule 1A must be prepared for each type of expense claimed. For instance, if a lessee has only other operating costs to claim, only one Supplemental Schedule 1A is required. If a lessee has other operating, other maintenance, and other overhead costs, three Supplemental Schedules 1A must be submitted.

Complete Supplemental Schedule 1A as follows:

STEP 1. Complete the payor ID information fields following Schedule 1A instructions.

STEP 2. Describe each expenditure item and list the amount. Lessees should retain receipts and invoices for future MMS review and/or audit.

STEP 3. Sum the expenditures and enter the total amount on the Total line.

STEP 4. Enter the total amount of the operations, maintenance, or overhead expenditures on Schedule 1A, lines 8 and 9, 14 and 15, and/or 19, respectively. Individual totals for operations, for maintenance, and for overhead expenditures must be computed on separate Supplemental Schedules 1A.

STEP 5. Check the appropriate box to indicate whether the information is proprietary or nonproprietary.

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SUPPLEMENTAL SCHEDULE 1A-- NON-ARM'S-LENGTH TRANSPORTATION SYSTEM/ SEGMENT OPERATIONS, MAINTENANCE, AND OVERHEAD EXPENDITURES

PAYOR IDENTIFICATION BLOCK
Payor Name and Code: ______
Accounting ID No: ______
Selling Arrangement Code: ______
Facility ID No: ______
Segment ID No: ______
Period: 19 to 19

Type of Expenditure - Describe

______	$ ______
______	______
______	______
______	______
______	______
______	______
______	______
______	______
______	______
______	______
______	______
______	______
______	______
______	______
______	______
______	______
______	______
______	______
______	______
______	______

Total $ ______

THIS INFORMATION SHOULD BE CONSIDERED (Please check one) ☐ PROPRIETARY ☐ NONPROPRIETARY

FORM MMS-4110 SUPPLEMENTAL SCHEDULE 1A (REV. 1/88)

FIGURE 5-4. Supplemental Schedule 1A—Non-Arm's-Length Transportation System/Segment Operations, Maintenance, and Overhead Expenditures, Form MMS-4110

5.8.5 Schedule 1B—Non-Arm's-Length Transportation System/Segment Depreciation and Capital Expenditure Summary, Form MMS-4110 (non-arm's-length or no-contract)

Schedule 1B—Non-Arm's-Length Transportation System/Segment Depreciation and Capital Expenditure Summary, Form MMS-4110 (fig. 5-5), summarizes the actual or estimated facility/segment depreciation and undepreciated capital investment costs for a non-arm's-length or no-contract situation.

A separate Schedule 1B must be completed for each segment. The costs of all segments are then accumulated on Schedule 1 to determine the total depreciation and undepreciated capital investment for the facility.

Complete Schedule 1B as follows:

STEP 1. Complete payor ID information by following Schedule 1A (fig. 5-3, p. 5-47) instructions.

Enter each facility/segment capital expenditure item on a separate line, as follows:

STEP 2. In column 1, Expenditure Item, identify the capital expenditure item.

STEP 3. In column 2, Initial Capital Investment and Date Placed in Service, enter the initial capital expenditure amount in the first part and the month and year the item was placed in service in the second part.

STEP 4. In column 3, Salvage Value, enter a reasonable salvage value.

STEP 5. In column 4, Depreciable Life/Years of Depreciation Taken to Date, enter the depreciable life of the expenditure in the first part and the number of years of depreciation taken to date in the second part.

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SCHEDULE 1B -- NON-ARM'S-LENGTH TRANSPORTATION SYSTEM/SEGMENT DEPRECIATION AND CAPITAL EXPENDITURE SUMMARY

PAYOR IDENTIFICATION BLOCK

Payor Name and Code: ______
Accounting ID No: ______
Selling Arrangement Code: ______
Facility ID No: ______
Segment ID No: ______
Period: 19 to 19

1	2	3	4	5	6	7
Expenditure Item	Initial Capital Investment and Date Placed in Service	Salvage Value	Depreciable Life/Years of Depreciation Taken to Date	Undepreciated Capital Investment at Beginning of Year	Depreciation	Undepreciated Capital Investment at End-of-Year
	$	$		$	$	$

Totals	$	$	8
Allocated to Segment (from line 22, Schedule 1A)	$	$	9
Segment Depreciation and Capital Expenditure (Line 8 x line 9) Enter in column g and e, Schedule 1	$	$	10

THIS INFORMATION SHOULD BE CONSIDERED (Please check one) ☐ PROPRIETARY ☐ NONPROPRIETARY

FORM MMS-4110 SCHEDULE 1B (REV 1/88)

FIGURE 5-5. Schedule 1B—Non-Arm's-Length Transportation System/Segment Depreciation and Capital Expenditure Summary, Form MMS-4110

STEP 6. In column 5, Undepreciated Capital Investment at Beginning of Year, enter the undepreciated capital investment at the beginning of the year (or beginning of the reporting period) as shown in the payor ID information field. Salvage value must be deducted from the initial capital investment.

STEP 7. In column 6, Depreciation, enter the amount of depreciation taken for the year or reporting period. In computing depreciation, the payor may elect to use either a straight-line depreciation method or a unit of production method. When an election is made, the payor may not alternate methods without MMS approval. Equipment cannot be depreciated below a reasonable salvage value.

NOTE

If a payor is reporting for only 6 months of the year or the pipeline has been in service for only 6 months, the payor must adjust the depreciation expense for the portion of the year in which the expense applies. For example, if the depreciable base of the pipeline is $2,000,000 and the estimated life is 20 years, the depreciation expense per year would be $100,000. The depreciation expense for 6 months would be calculated as follows:

$$\text{Depreciation} = \$100{,}000 \times \frac{6}{12} = \$50{,}000$$

STEP 8. In column 7, Undepreciated Capital Investment at End-of-Year, enter the undepreciated capital investment at the end of the year. This is computed by subtracting depreciation (column 6) from the beginning of the year (or beginning of the reporting period) undepreciated capital investment (column 5). This amount is used as the next year's beginning of the year undepreciated capital investment.

STEP 9. Total columns 5 and 6 and enter the amounts on line 8.

STEP 10. Enter these amounts on Schedule 1 (fig. 5-2, p. 5-38), parts A and/or B, columns g and e, respectively.

STEP 11. On line 9, columns 5 and 6, enter the Allocated to Segment amount from line 22 of Schedule 1A (fig. 5-3, p. 5-47).

STEP 12. For columns 5 and 6, multiply line 8 by line 9, and enter the amounts on line 10.

STEP 13. Enter these amounts from line 10 on Schedule 1 (fig. 5-2, p. 5-38), parts A and/or B, columns g and e, respectively.

STEP 14. Check the appropriate box to indicate whether the information is proprietary or nonproprietary.

5.9 Reporting on Form MMS-2014

Transportation allowances must be reported as a separate line entry on Form MMS-2014 under column 11 using TC 11 unless MMS approves a different reporting procedure (30 CFR 206.55(c)(4)). When reporting a transportation allowance, the lessee reports the royalty due (TC 01) on one line based on the full quantity of oil (fig. 5-6). On the second line, the lessee reports the transportation allowance (TC 11) as a **positive** royalty quantity and a negative royalty value in columns 17 and 18, respectively. Royalties are due on the value of the oil minus the transportation allowance. Refer to the *Oil and Gas Payor Handbook, Volume II*, for detailed information for reporting on Form MMS-2014.

5.10 Due Dates for Allowance Reports

For reporting transportation costs incurred under **arm's-length** contracts, Page 1 and Schedule 1 of Form MMS-4110 must be submitted. For **non-arm's-length** contracts or no-contract situations, Page 1 and all appropriate schedules must be submitted. The appropriate forms must be filed with MMS prior to the time, or at the same time, the transportation deduction is reported on Form MMS-2014. A Form MMS-4110 received by MMS by the end of the month when Form MMS-2014 is due will be considered timely filed (30 CFR 206.55(c)(1)(i) and 30 CFR 206.55(c)(2)(i)). If the due date falls on a weekend or a Federal holiday, the form will be considered timely filed if it is received by MMS by 4 p.m. mountain time on the next Government business day.

OMB 1010-0022 (Expires August 31, 20XX)

U.S. DEPARTMENT OF THE INTERIOR
Minerals Management Service – Royalty Management Program

Report of Sales and Royalty Remittance
Form MMS-2014

Page ____ of ____

For MMS Use Only

REPORT MO./YR.: 0 2 9 0

1 PAYOR'S NAME Bob Henry Oil Company

2 PAYOR CODE 1 2 3 4 5

3 FEDERAL [ ] OR INDIAN [X]

3a PAYOR-ASSIGNED DOCUMENT NUMBER _ _ _ _ _ _

4	5 RESERVED FOR PREPARER'S USE	6 ACCOUNTING IDENTIFICATION (AID) NUMBER	7 PROD CODE	8 REG PRICE CODE	9 SELL ARR CODE	10 SALES MONTH/ YEAR	11 TRANS CODE	12 ADJ REAS CODE	13 SALES QUANTITY	14 QUALITY MEASURE-MENT	15 CALC METH	16 SALES VALUE	17 ROYALTY QUANTITY	18 ROYALTY VALUE	19 PMT METH CODE
1		5160012340001	01		001	01/90	01		2,000 00			40,000.00	250 00	5,000 00	
2		5160012340001	01		001	01/90	11						-250 00	-375 00	
3															
4															
5															

FIGURE 5-6. Reporting Example, Report of Sales and Royalty Remittance, Form MMS-2014

The initial Form MMS-4110 is effective for a reporting period beginning the month the lessee is first authorized to deduct an allowance. The effective period continues until the end of the calendar year, until the contract or rate terminates, or until the contract or rate is modified or amended, whichever is earlier (30 CFR 206.55(c)(1)(ii) and 30 CFR 206.55(c)(2)(ii)).

For succeeding reporting periods, the lessee must submit the appropriate forms within 3 months after the end of the calendar year, or after the applicable contract or rate is amended, modified, or terminated, whichever is earlier. However, MMS may approve a longer period, during which the lessee will continue to use the allowance rate from the previous reporting period (30 CFR 206.55(c)(1)(iii) and 30 CFR 206.55(c)(2)(iii)).

Transportation allowances that were in effect as of March 1, 1988, were allowed to continue until such allowances terminated or until December 31, 1988, whichever was earlier.

5.11 Extension to File Form MMS-4110

To request an extension to file Form MMS-4110, the lessee of an Indian lease must submit an extension request, with supporting documentation, in writing on or before the original due date of the form. MMS's policy is to grant a maximum 90-day extension to file Form MMS-4110. The extension request must contain the following information:

- Payor number
- Form number (Form MMS-4110)
- MMS lease number
- Report type (extension to file estimate, actual, or both)
- Reporting period for which the extension applies

If the lessee is requesting an extension to file an initial report, the allowance may not be claimed on Form MMS-2014 until the allowance form is filed (regardless of whether or not an extension is granted). If an allowance is claimed on Form MMS-2014 before the initial Form MMS-4110 is filed, interest is assessed.

If the lessee is requesting an extension to file a continuing report, the lessee may continue to use the allowance rate from the previous reporting period until Form MMS-4110 is filed for the current reporting period.

5.12 Application for Exceptions

MMS may approve an exception to the reporting requirements under the following three conditions:

- When transportation costs exceed the 50-percent limitation;

- When the lessee applies for an exception from computing actual costs and completing all addendum schedules under non-arm's-length or no-contract situations; and

- When a lessee of an Indian lease requests approval to claim a transportation allowance more than 3 months prior to the date that the initial Form MMS-4110 was filed.

The lessee must submit a request for the exception annually. If MMS approves the request, the lessee should follow the arm's-length reporting requirements.

5.12.1 Exception to 50-percent limitation

The transportation allowance deduction on the basis of a selling arrangement cannot exceed 50 percent of the value of the oil (30 CFR 206.104(b)(1) and 30 CFR 206.54(b)(1)). However, on request of a lessee, MMS may approve a transportation allowance in excess of the 50-percent limitation if the lessee meets the following conditions:

- The lessee submits a written application for an exception and provides all relevant documentation for MMS to make a determination. The submitted information should include, but not be limited to:
  - A complete list of AID numbers, product codes, selling arrangement numbers, and payor code(s);
  - A full description of the transportation system, contracts, invoices, or tariffs;
  - Points of sale and delivery;
  - Production volumes;
  - Costs and explanation of costs; and
  - Applicable time periods.
- A request for an exception to the 50-percent limitation is submitted annually if actual costs exceed 50 percent of the value of the oil each year.
- The lessee demonstrates that the transportation costs incurred in excess of the limitation were reasonable, actual, and necessary.
- The value for royalty purposes under any selling arrangement is not reduced to zero.

5.12.2 Exception to compute actual costs

If a lessee has a non-arm's-length transportation contract or has no contract, including those situations where the lessee performs transportation for itself, the transportation allowance is based on the lessee's reasonable, actual costs (30 CFR 206.105(b) and 30 CFR 206.55(b)). However, on request of a lessee, MMS may grant an exception from the requirement to compute actual costs only if the lessee has a FERC- or State-approved tariff (30 CFR 206.105(b)(5) and 30 CFR 206.55(b)(5)).

MMS will deny the lessee's request if the tariff is excessive compared to arm's-length transportation charges in the area. If there are no arm's-length charges, MMS will deny the lessee's request if:

- No FERC or State cost analysis exists and, if MMS objects to a lessee's filing, the appropriate agency declines to investigate the filing; and
- The tariff significantly exceeds the lessee's actual costs.

5.12.3 Exception to 3-month retroactive limitation

An oil transportation allowance may be claimed retroactively for a period not more than 3 months prior to the first day of the month in which the allowance report is filed with MMS. However, MMS may approve allowances to be claimed retroactively for a period longer than 3 months upon a showing of good cause by the lessee (30 CFR 206.55(a)(1)(i) and 30 CFR 206.55(b)(1)). To receive approval to exceed the 3-month retroactive allowance filing requirement, the lessee must request approval in writing and provide evidence of good cause for failing to meet the deadline for filing allowances.

MMS administratively defines "good cause" in terms of two basic elements:

1. **Justifiable delay**: Events causing "justifiable delay" must have been (1) outside the individual's control, (2) within immediate proximity to the due date, and (3) a contributing factor in the lessee's failure to timely file the appropriate allowance forms. Contributing

factors include natural disasters or death or illness of the lessee or a member of the lessee's immediate family.

2. **Reasonable diligence**: Evidence that the lessee was diligent up to the point in time when the event causing justifiable delay occurred **and** acted promptly after the cause of the delay was identified and/or resolved.

Denial of an allowance is a serious matter because it may substantially increase the value of production for royalty purposes. However, MMS provides a period of 3 months in which to submit allowance forms, which is considered a reasonable length of time. A lessee that is acting in a diligent manner should be able to submit the forms within the 3-month period. If this is impossible, the lessee should submit an estimated allowance or request an extension to file before the due date for the allowance forms. Failure to file because the lessee forgot or was too busy is **not** considered sufficient justification to approve a retroactive period.

5.13 Interest Assessments for Incorrect or Late Reports and Failure to Report—Indian Leases Only

The lessee of an Indian lease must file a Form MMS-4110 **before** claiming a processing allowance on the Form MMS-2014. If the lessee files an erroneous Form MMS-4110, files the Form MMS-4110 **after** claiming an allowance on the Form MMS-2014, or fails to file the Form MMS-4110, the lessee will be charged interest on the amount of the deduction until the filing requirements are met. In addition, if the lessee does not file the correct reports within the 3-month allowance filing period, the lessee must pay back the allowance amount that was claimed on the Form MMS-2014.

Interest on royalty underpayments is determined under 30 CFR 218.54 as follows:

a. An interest charge shall be assessed on unpaid and underpaid amounts from the date the amounts are due.

b. The interest charge on late payments shall be at the underpayment rate established by the *Internal Revenue Code*, 26 U.S.C. 6621(a)(2)(Supp. 1987).

c. Interest will be charged only on the amount of the payment not received. Interest will be charged only for the number of days the payment is late.

If a lessee deducts a transportation allowance on its Form MMS-2014 before Form MMS-4110 is filed with MMS, a noncompliance letter is issued every month until the requirements of the regulations are met. MMS began issuing noncompliance letters with the August 1989 report month. No noncompliance letters were issued prior to that month. However, lessees are responsible for all report months before August 1989, even though no letter was sent.

Any transportation allowance line (TC 11) claimed on Form MMS-2014 for a sales month for a specific payor number, AID number, product code, and selling arrangement must have a corresponding allowance Form MMS-4110 on file covering the same sales month for the same specific payor number, AID number, product code, and selling arrangement combination.

To avoid an interest assessment for late filing, lessees may request an extension to file the allowance Form MMS-4110 up to a maximum of 90 days. However, if an extension is requested for the initial filing, the lessee may not deduct a transportation allowance on its Form MMS-2014 until the Form MMS-4110 is actually filed. The procedures for filing an extension are discussed in "Extension to File Form MMS-4110" on page 5-56.

5.14 Adjustments

If the lessee's actual transportation allowance differs from the allowance reported, the lessee must file a corrected Form MMS-2014. Data are reported on Form MMS-2014 on a sales month basis; therefore, if an adjustment is needed, there must be a separate adjustment for each sales month.

If the actual transportation allowance is less than the amount the lessee has estimated and claimed during the reporting period, the lessee is required to pay additional royalties due plus interest (30 CFR 218.54). Interest is computed retroactively to the first month the lessee is authorized to deduct a transportation allowance. The lessee must submit a corrected Form MMS-2014 to reflect actual costs, together with any payment due, under instructions provided by MMS.

If the actual transportation allowance is greater than the amount the lessee has estimated and claimed during the reporting period, the lessee is entitled to a credit without interest. The lessee must submit a corrected Form MMS-2014 to reflect actual costs and follow the recoupment or refund procedure specified by MMS. For offshore leases, any recoupment or refund request must also follow the procedures outlined in the "Dear Payor" letters dated December 20, 1991, and January 15, 1993. (These letters explain the December 15, 1981, Solicitor's Opinion entitled, "Refunds and Credits Under the Outer Continental Shelf Lands Act," M-36942, 88 I.D. 1090, 1101-1102 (1981).) The lessee should contact the appropriate Royalty Error Correction representative for specific instructions. See "Important Addresses and Phone Numbers" on page 1-5.

5.15 Computer-Generated Form MMS-4110—Indian Leases Only

Prior written approval from MMS is required if a lessee of an Indian lease wants to submit its allowance information on automated allowance forms in lieu of using official MMS forms. The lessee must submit a copy of its proposed computer-generated form to MMS. The placement of all fields on the computer-generated form must be identical to the fields on the official MMS form.

6. Gas Transportation Allowances

This chapter describes the procedures for calculating and reporting transportation allowances for Federal and Indian unprocessed gas, residue gas, and gas plant products. Gas transportation allowances are applicable for transporting gas and gas plant products from a lease to a sales point or point of value determination off the lease, and, if appropriate, from the lease to a gas processing plant off the lease and from the plant to a point away from the plant (30 CFR 206.156 and 30 CFR 206.176).

The royalty value of gas is normally determined at the lease, unit, or CA (collectively referred to as the lease). However, value may also be determined at a point off the lease, and the lessee must incur the expense of delivering the gas to that point. In these cases, the lessee's reasonable, actual transportation costs, not to exceed 50 percent of the sales value, can be deducted as a transportation allowance (30 CFR 206.156 and 30 CFR 206.176). Transportation costs cannot be transferred between selling arrangements or to other products.

Indian lessees must submit a Gas Transportation Allowance Report, Form MMS-4295, documenting gas transportation allowances claimed on the Report of Sales and Royalty Remittance, Form MMS-2014 (30 CFR 206.157(c) and 30 CFR 206.177(c)). All transportation allowances reported on Forms MMS-4295 and MMS-2014 are subject to audit. Federal lessees are no longer required to file allowance forms.

For Indian leases, discrepancies between the allowance forms and allowances reported on Form MMS-2014, as well as late or incorrect allowance forms or failure to file the appropriate allowance forms, could result in a disallowance of deductions claimed on Form MMS-2014, assessment of interest, or both.

The regulations covering gas transportation allowances for Federal leases are at 30 CFR 206.156 and 30 CFR 206.157. The regulations covering gas transportation allowances for Indian leases are at 30 CFR 206.176 and 30 CFR 206.177.

To ask questions about gas transportation allowances, contact the Royalty Valuation Division. See "Important Addresses and Phone Numbers" on page 1-5.

6.1 Determining If the Lessee Is Entitled to Claim a Gas Transportation Allowance

Even though lessees may incur transportation costs, in certain situations the lessee is prohibited from claiming these costs as a transportation allowance. The following sections discuss these situations.

6.1.1 Section 6 leases

Gas produced from leases originally issued by the State of Louisiana under its 1942 lease form and now administered by MMS under Sections 6 and 7 of the OCSLA (43 U.S.C. 1337 (1953)) is currently not eligible for a transportation allowance. Leases issued under the 1942 lease form are:

- OCS 0002 through 0091
- OCS 0093 through 0183
- OCS 0194 through 0199
- OCS 0201 through 0211
- OCS 0216 through 0227
- OCS 0232 through 0309
- OCS 0311 through 0356
- OCS 0360 through 0402
- OCS-G 012345 through 012349

Lease numbers OCS 0092 and 0310 are exceptions and are not prohibited from filing for a transportation allowance.

6.1.2 NPSLs

NPSLs were issued under Section 8(a) of OCSLA. OCSLA required that alternative bidding systems be established for leases on the OCS. The *Federal Register* Notice entitled "Fixed Net Profit Share Bidding System for Outer Continental Shelf Oil and Gas Leases and Accounting Procedures for Determining Net Profit Share Payments: Final Rule" (45 FR 36784—May 30, 1980) established the accounting method to be used to report costs and revenues for NPSLs.

Rather than paying a fixed royalty, the NPSL operator pays a fixed percentage of the net profits based on the revenue received from the production and sale of oil and gas minus the cost of production. Under this system the lessee recovers expenses of exploration and development, plus a reasonable return on that investment, from production revenues prior to any net profit share payment to the Federal Government.

The MMS Director's approval of a Development and Coordination Document, combined with the language at 30 CFR 220.011(g) and 30 CFR 220.011(o), permits the lessee to include, in the NPSL capital account, allowable costs associated with transportation and processing. Thus, transportation and processing allowances for NPSLs should not be claimed as separate deductions on Form MMS-2014.

6.1.3 Exchange agreements

The costs incurred under certain types of exchange agreements may qualify for a transportation allowance (see Chapter 3, "Oil Valuation," and Chapter 4, "Gas Valuation").

For example, under an arm's-length exchange agreement, Swivel Production (Swivel) delivers unprocessed gas to Basin Transportation (Basin). Basin in turn redelivers the unprocessed gas to Swivel at Midstate Meter Station. Swivel pays Basin a $0.20/Mcf location differential at Midpoint Meter Station. Value is determined at the first sales point downstream of Midstate Meter Station. A transportation allowance of $0.20/Mcf location differential would then be allowable.

6.1.4 Transportation factors

If an arm's-length sales contract price or an arm's-length posted price includes a provision by which the listed price is reduced by a transportation factor and the lessee is paid a net amount by the purchaser, MMS considers this charge to be a transportation factor (30 CFR 206.157(a)(5) and 30 CFR 206.177(a)(5)). MMS does not consider the transportation factor to be a transportation allowance. MMS considers a transportation factor to be an adjustment to the value rather than an out-of-pocket transportation expense.

In cases where a transportation charge is treated as an adjustment to value and considered to be a transportation factor, the transportation factor may be used in determining the lessee's gross proceeds. The lessee reports its royalty line net of the transportation charge. A separate transportation allowance line on Form MMS-2014 is not required. A gas transportation allowance Form MMS-4295 is not required from either Federal or Indian lessees in this case.

The transportation factor may not exceed 50 percent of the base price of the gas without MMS approval.

If the lessee has a marketing affiliate that meets the MMS definition of a marketing affiliate, and the marketing affiliate's arm's-length contract price is reduced by a transportation factor, MMS considers the transportation charge as a factor, not an allowance. The lessee reports the royalty line net of transportation without prior MMS approval.

6.1.5 Gas not in marketable condition

The lessee is required to place lease production in marketable condition at no cost to the lessor. A transportation allowance is not permitted for gas that is not in marketable condition. Any costs associated with placing the gas in marketable condition cannot be included as a transportation cost.

The lessee is responsible for bearing all marketing-related costs such as those for gathering, dehydration, nonallowable compression, initial separation, storage, measurement, treatment (such as sweetening or purification), market brokerage, or other marketing activities.

For example, if an arm's-length contract states that the lessee is charged $0.75/Mcf for transportation, storage, and measurement, then the lessee must determine what costs are allocable to transportation, storage, and measurement and deduct only the portion allocated to transportation.

Gathering. Gathering is defined as the movement of lease production to a central accumulation and/or treatment point on the lease, unit, or CA, or to a central accumulation or treatment point off the lease, unit, or CA as approved by BLM (onshore) or MMS (offshore).

Gathering is considered part of placing lease production in marketable condition and therefore is not allowable as a transportation cost. Gathering is not considered transportation of marketable lease production to a sales point off the lease.

NOTE

A gas processing plant is usually not considered a central accumulation or treatment facility.

The distinction between gathering, for which no deduction is permitted, and transportation, which allows for a deduction, hinges on a number of factors. Using a pipeline as an example, the following questions will aid in distinguishing between gathering and transportation:

- Does the pipeline segment lie entirely within the lease, unit, or CA?

  If the answer is "yes," the pipeline is a gathering line, and no deductions for transportation are permitted.

- Is the pipeline segment upstream of the central accumulation and/or treatment point?

  If the answer is "yes," the pipeline is a gathering line, and no deductions for transportation are permitted.

- Is the pipeline segment beyond the initial treatment point, central accumulation point, or measurement facilities?

  If the answer is "yes," the pipeline is not a gathering line and may be eligible for a transportation allowance.

- Is the pipeline segment a link in the continuous flow of marketable product to the point of delivery?

  If the answer is "yes," the pipeline is not a gathering line and may be eligible for a transportation allowance.

6.2 Limitations and Exceptions to Transportation Allowances

Transportation allowances are calculated on a selling arrangement basis and are limited to 50 percent of the value of unprocessed gas, residue gas, or gas plant products at the point of sale or value determination. Costs incurred for transportation under one selling arrangement may not be transferred to another selling arrangement or product. This limitation includes transportation factors, which cannot exceed 50 percent of the value of the product without MMS approval. For example, if an Mcf of gas is being sold for $1.50, then the transportation allowance is limited to $0.75/Mcf ($1.50 x 50%).

If the lessee incurs transportation costs in excess of 50 percent of the value of unprocessed gas, residue gas, or gas plant products under a selling arrangement, the lessee may request MMS approval of a transportation allowance deduction in excess of the limitation. MMS requires the lessee to submit an application for exception to the limitation annually (see "Exception to 50-percent limitation" on p. 6-65 for more information).

MMS makes a determination based on the merits of the case. However, for royalty purposes, under no circumstances shall the value of unprocessed gas, residue gas or gas plant products under any selling arrangement be reduced to zero. The lessee may not claim a transportation allowance that is greater than 99 percent of the value of unprocessed gas, residue gas, or gas plant products under any selling arrangement.

The lessee may not report allowances in excess of the 50-percent limit on Form MMS-2014 until MMS approves the lessee's application for an exception.

6.3 Allowable and Nonallowable Gas Transportation Costs

Transportation allowances are granted for the reasonable, actual costs incurred for and directly related to transportation of marketable gas by pipeline, truck, barge, or other conveyance to a sales point or value determination point off the lease.

Acceptable transportation costs include:

- Pipeline costs or fees;
- Barging or trucking costs or fees, including loading or unloading costs;
- Rail car and tanker costs; and
- Costs for reseparation of gas (if those costs are related to transportation of liquids included in the gas stream after initial separation).

6.3.1 Pipeline losses

Pipeline losses are actual or theoretical reductions in the volume of gas that travels through a pipeline. Pipeline losses are the result of either real, physical losses or errors in the measurement of gas.

The lessee may incur the cost of a pipeline loss by either a reduction in the volume of gas (which results in lower gross proceeds received) or a reduction in the value of gas on which the lessee received payment.

Allowable costs. Under an arm's-length contract, if the lessee incurs an out-of-pocket expense for a pipeline loss beyond the point of royalty settlement (a fuel charge), MMS may accept the value of the loss as an appropriate transportation cost. If the lessee is charged an actual reduction in the volume of gas delivered to the transporter, the lessee must convert the volume into a dollar amount. Royalty is always due on 100 percent of the volume measured at the approved point of royalty settlement.

For example, assume the lessee transports 4,000 MMBtu of gas valued at $2/MMBtu. The lessee is charged 2 percent of the total volume for transportation under an arm's-length contract or as part of a tariff approved by FERC or the State. The 2-percent volume reduction is converted to a dollar amount as follows:

$$\text{total volume transported} \times \text{volume reduction charge} \times \text{value per Mcf} = \text{transportation costs}$$

$$4{,}000 \text{ MMBtu} \times 0.02 \times \$2/\text{MMBtu} = \$160$$

Nonallowable costs. For non-arm's-length contracts or no-contract situations, actual or theoretical losses (based on volume or value) are not allowable transportation costs. However, these costs are allowable if they are based on a FERC- or State-approved tariff.

6.3.2 Arm's-length costs

MMS allows a deduction for the reasonable, actual transportation costs incurred by the lessee under an arm's-length contract. If a question arises as to the legitimacy of an arm's-length contract, the lessee has the burden of demonstrating that its contract is arm's-length in accordance with MMS standards. The criteria defining an arm's-length contract are provided in Chapter 4, "Gas Valuation."

Allowable costs. Costs directly related to the actual transportation of gas are allowable costs.

For example, an arm's-length contract states the transportation charge is $0.75/Mcf, and the lessee pays that amount as an out-of-pocket expense. The lessee claims $0.75/Mcf as a transportation deduction.

Nonallowable costs. Costs not directly related to the actual transportation of gas are nonallowable costs. The lessee may not claim a transportation allowance that is greater than the consideration actually transferred, either directly or indirectly, from the lessee to the transporter regardless of what costs or fees are reflected in the arm's-length contract. If the contract lists more costs than the lessee actually pays, only that portion the lessee pays is eligible for a transportation allowance.

For example, an arm's-length contract states that the transportation charge is $0.10/Mcf; however, the lessee pays only $0.05/Mcf as an out-of-pocket expense. The lessee claims $0.05/Mcf as a transportation deduction.

6.3.3 Non-arm's-length costs

If the lessee transports its gas through its own transportation system (a no-contract situation) or through its affiliate's transportation system (a non-arm's-length contract situation), transportation costs are divided into two categories:

- Costs associated with capital investment, and
- Costs associated with operations, maintenance, and overhead, collectively referred to as operating and maintenance costs.

MMS may request copies of invoices to verify capital costs and operating and maintenance costs claimed by the lessee.

6.3.3.1 Capital costs

Allowable costs. Depreciable fixed assets (including costs of delivery and installation of capital equipment) that are an integral part of the transportation system are allowable capital costs (30 CFR 206.157(b)(2) and 30 CFR 206.177(b)(2)). The following capital items are allowable costs:

- Garages and warehouses
- Rail haulage equipment including rail spurs
- Trucks
- Barges
- Pipeline compressors and pumps on the transportation system
- Roads associated with the transportation system

Nonallowable costs. The following costs are nonallowable deductions:

- Nondepreciable property, such as land.
- Costs incidental to marketing; for example, on-lease and other nonallowable compressors, separators, dehydrators, and heaters/treaters.
- Schools, hospitals, roads, sewers, and other capital improvements or equipment not an integral part of the transportation facility.

- The capital costs associated with the preparation of an environmental impact statement. (However, capital costs for environmental equipment that is an integral part of the transportation facility are allowable.)

6.3.3.2 Operating and maintenance costs

Allowable costs. Nondepreciable costs that are directly attributable to the operation and maintenance of a transportation facility/segment are allowable operating and maintenance costs. These costs include:

- Salaries and wages paid to employees and supervisors while engaged in the operation and maintenance of transportation equipment and facilities.
- Fuel and utility costs directly related to transporting gas.
- Chemicals (including rust preventives and thinning agents) and lubricants used for protection or cleaning of transportation facilities.
- Repairs, labor, materials, and supplies directly related to transportation equipment and facilities.
- Port and toll fees, insurance, ad valorem property taxes, and payroll taxes (Federal and State income taxes are not allowable deductions).
- Arm's-length rental, leasing, or contract service costs for transportation equipment, facilities, and onsite installation or maintenance of equipment and facilities.
- General administrative overhead costs (telephone service, employee benefits, vehicle expenses, office supplies, etc.) directly attributable and allocable to the operation and maintenance of the transportation system. The lessee should maintain records to support all overhead costs included in a gas transportation allowance.

The total of these costs is limited to those reasonable expenditures directly attributable and allocable to the operation and maintenance of transportation equipment and facilities.

Nonallowable costs. Costs that are not directly attributable and allocable to transportation of gas are nonallowable costs. These costs include:

- Costs incidental to marketing; for example, on-lease gathering, storage, on-lease compression, separation, dehydration, heating, treatment, metering, and water removal.
- Theoretical or actual pipeline losses under a **non-arm's-length** or **no-contract** situation (see "Pipeline losses" on p. 6-7).
- Federal and State income taxes, production taxes, royalty payments, or fees, such as State and Indian severance taxes.
- Costs for services that the lessee is obligated to perform at no cost to the Federal Government or Indian lessor, such as costs associated with the construction of schools, hospitals, roads, and sewers.

6.4 Allocation of Costs

If gas transportation costs cannot be determined from the arm's-length contract, non-arm's-length contract, or no-contract situation, the total transportation costs must be allocated to all products in a consistent and equitable manner. The lessee must propose a cost allocation method to MMS and submit all data relevant to its proposal. The lessee may use its proposed allocation method until MMS issues its determination. The initial proposal must be submitted within 3 months of the last day of the month for which the lessee first deducts a transportation allowance. MMS will approve the method unless MMS determines that the method is not consistent with the purposes of the regulations.

Non-royalty-bearing products. The lessee is not permitted to deduct the costs of transporting non-royalty-bearing products without MMS approval (30 CFR §§ 206.157(a)(2)(i), 206.177(a)(2)(i), 206.157(b)(3)(i), and 206.177(b)(3)(i). In computing a transportation allowance for a gaseous and/or liquid stream that contains both royalty-bearing and non-royalty-bearing products, only the costs associated with transporting the royalty-bearing portion of the stream are deductible.

6.4.1 Gaseous streams

If a gas transportation system contains other gaseous products in addition to hydrocarbon gas, the cost to transport each product is determined separately and allocated to each product for royalty valuation and reporting purposes. The requirements for allocating transportation costs are the same for **arm's-length** (30 CFR 206.157(a)(2)(i) and 30 CFR 206.177(a)(2)(i)) and **non-arm's-length** contracts and **no-contract** situations (30 CFR 206.157(b)(3)(i) and 30 CFR 206.177(b)(3)(i)). The cost allocated to each product must be based on the ratio of the volume of that product to the total volume of all products (excluding waste). The allocation is based on actual contract costs.

In computing the cost allocated to each product, the lessee must determine if each product is:

- Royalty-bearing,
- Non-royalty-bearing, or
- Waste.

NOTE

Transportation costs for a gaseous stream are allocated only to the royalty-bearing and non-royalty-bearing products. For allocation purposes, a waste product is considered neither royalty-bearing nor non-royalty-bearing. Therefore, the waste product volume is excluded from the cost allocation.

For example, assume the lessee contracts to transport 1,000 Mcf of gas. The lessee is charged $0.20/Mcf for transportation. The stream consists of 975 Mcf of gas, 10 Mcf of CO_2, and 15 Mcf of helium. Assume that CO_2 is a waste product and helium is a non-royalty-bearing product.

Determine the gas transportation allowance as follows:

1. Compute the total allowable costs incurred under the contract.

$$\$0.20/\text{Mcf} \times 1{,}000\ \text{Mcf} = \$200$$

2. Compute the volume of each royalty-bearing and non-royalty-bearing product and the total volume. (The 10 Mcf of waste [CO_2] is excluded.)

   Royalty-bearing product (gas): 975 Mcf
   Non-royalty-bearing product (helium): 15 Mcf

   $$975 \text{ Mcf} + 15 \text{ Mcf} = 990 \text{ Mcf}$$

3. Compute the cost allocated to each product by multiplying the total cost by the ratio of the volume of each royalty-bearing and non-royalty-bearing product to the total volume of these products.

   Royalty-bearing product (gas):

   $$\frac{\$200 \times 975 \text{ Mcf}}{990 \text{ Mcf}} = \$196.969697$$

   Non-royalty-bearing product:

   $$\frac{\$200 \times 15 \text{ Mcf}}{990 \text{ Mcf}} = \$3.030303$$

4. Compute the gas transportation allowance by dividing the total cost allocated to gas by the total volume of gas.

   $$\frac{\$196.969697}{975 \text{ Mcf}} = \$0.202020/\text{Mcf}$$

6.4.2 Liquid and gaseous streams

If a gas transportation system contains both liquid and gaseous products, the cost to transport each product is determined separately and allocated to each product for royalty valuation and reporting purposes. For an **arm's-length contract**, if the lessee can determine from the contract the transportation costs attributable to each product, the lessee should use those actual costs (30 CFR 206.157(a)(3) and 30 CFR 206.177(a)(3)). Otherwise, the requirements for allocating transportation costs are the same for arm's-length and **non-arm's-length** contracts and **no-contract** situations (30 CFR 206.157(b)(4) and 30 CFR 206.177(b)(4)).

For arm's-length contracts where costs cannot be determined from the contract, and for non-arm's-length contracts and no-contract situations, the lessee must propose an allocation procedure to MMS. The proposed method should be based on the ratio of the volume of each product to the total volume of all products (excluding waste).

The lessee may use its proposed allocation method to calculate an allowance until MMS accepts or rejects the proposed method. In its proposal, the lessee must explain its method and submit all available supporting data. The initial proposal must be submitted within 3 months after the last day of the month for which the lessee requests the allowance, unless MMS approves a longer period. Based on the information submitted and other information MMS considers pertinent, MMS will accept or reject the lessee's calculated gas transportation allowance.

In computing the cost allocated to each product, the lessee must determine if each product is:

- Royalty-bearing,
- Non-royalty-bearing, or
- Waste.

NOTE

Transportation costs for a liquid and gaseous stream are allocated only to the royalty-bearing and non-royalty-bearing products. For allocation purposes, a waste product is considered neither royalty-bearing nor non-royalty-bearing. Therefore, the waste product volume is excluded from the cost allocation.

For example, assume the lessee contracts to transport 1,000 Mcf of residue gas and reinjects 10 bbl of oil into the gas stream. The lessee is charged $0.30/Mcf for transportation. The stream consists of 975 Mcf of residue gas, 10 Mcf of CO_2, and 15 Mcf of helium. Assume that CO_2 is a waste product and helium is a non-royalty-bearing product.

Determine the gas transportation allowance as follows:

1. Convert the barrels of oil to Mcf using a standard conversion factor of 5.825 Mcf/bbl[1].

$$10 \text{ bbl} \times 5.825 \text{ Mcf} = 58.25 \text{ Mcf}$$

2. Compute the total allowable costs incurred under the contract:

$$(58.25 \text{ Mcf} + 1{,}000 \text{ Mcf}) \times \$0.30/\text{Mcf} = \$317.475$$

3. Compute the volume of each royalty-bearing and non-royalty-bearing product and the total volume. (The 10 Mcf of waste [CO_2] is excluded.)

   Royalty-bearing product (oil): 58.25 Mcf
   Royalty-bearing product (residue gas): 975 Mcf
   Non-royalty-bearing product (helium): 15 Mcf

$$58.25 \text{ Mcf} + 975 \text{ Mcf} + 15 \text{ Mcf} = 1{,}048.25 \text{ Mcf}$$

4. Compute the cost allocated to each product by multiplying the total cost by the ratio of the volume of each royalty-bearing and non-royalty-bearing product to the total volume of these products.

   Royalty-bearing product (residue gas):

$$\frac{\$317.475 \times 975 \text{ Mcf}}{1{,}048.25 \text{ Mcf}} = \$295.290365$$

   Royalty-bearing product (oil):

$$\frac{\$317.475 \times 58.25 \text{ Mcf}}{1{,}048.25 \text{ Mcf}} = \$17.641706$$

   Non-royalty-bearing product (helium):

$$\frac{\$317.475 \times 15 \text{ Mcf}}{1{,}048.25 \text{ Mcf}} = \$4.542929$$

[1] Energy Information Administration, *Monthly Energy Review*, Table A2, Approximate Mcf Equivalent of Petroleum Products, June 1992.

5. Compute the gas transportation allowance by dividing the total cost allocated to the gas by the total volume of gas. (The lessee would also compute the oil transportation allowance in the same way, then convert the cost into a per-barrel cost using the conversion factor [see “Liquid and gaseous streams” on p. 5-13].)

$$\frac{\$295.290365}{975\text{ Mcf}} = \$0.302862/\text{Mcf}$$

6.4.3 Allocation based on product value

As an alternative to cost allocation on a volumetric basis, the lessee may propose a cost allocation method to MMS based on values of the products transported. MMS will approve the lessee’s proposed method unless MMS determines that the method is not consistent with the purposes of the transportation regulations (30 CFR §§ 206.157(a)(2)(ii), 206.177(a)(2)(ii), 206.157(b)(3)(ii), and 206.177(b)(3)(ii)).

For example, assume the lessee contracts to transport 1,000 Mcf of gas and reinjects 10 bbl of condensate (oil) into the gas stream. The lessee is charged $0.30/Mcf for transportation. The stream consists of 975 Mcf of gas and 25 Mcf of CO_2. Assume that CO_2 is a waste product. Oil value is $15/bbl; gas value is $3/Mcf at 1,000 Btu/cf. Determine the gas transportation allowance as follows:

1. Convert the barrels of oil to Mcf using a standard conversion factor of 5.825 Mcf/bbl[2].

$$10\text{ bbl} \times 5.825\text{ Mcf/bbl} = 58.25\text{ Mcf}$$

2. Compute the total allowable costs incurred under the contract:

$$(58.25\text{ Mcf} + 1{,}000\text{ Mcf}) \times \$0.30/\text{Mcf} = \$317.475$$

3. Compute the value of each product and the total product value.

Gas value: $975\text{ Mcf} \times \$3/\text{Mcf} = \$2{,}925$

Oil value: $10\text{ bbl} \times \$15/\text{bbl} = \$150$

[2] Energy Information Administration, *Monthly Energy Review*, Table A2, Approximate Heat Content of Petroleum Products, June 1992.

Total value: $2,925 + $150 = $3,075

4. Compute the costs allocated to each product by multiplying the total cost by the ratio of the value of each product to the total value of all products:

Gas: $$\frac{\$317.475 \times \$2,925}{\$3,075} = \$301.988415$$

Oil: $$\frac{\$317.475 \times \$150}{\$3,075} = \$15.486585$$

5. Compute the gas transportation allowance by dividing the total cost allocated to gas by the total volume of gas. (The lessee would also compute the oil transportation allowance in the same way.)

$$\frac{\$301.988415}{975\text{ Mcf}} = \$0.309732/\text{Mcf}$$

6.5 Units of Measurement

Where the lessee's payments for transportation under an arm's-length contract are not on a dollar-per-unit basis, the lessee must convert whatever consideration is paid to a dollar amount (30 CFR 206.157(a)(4) and 30 CFR 206.177(a)(4)).

For example, assume the lessee transports 40,000 MMBtu of gas valued at $2/MMBtu. The lessee is charged 5 percent of the total volume for transportation. The 5-percent transportation charge is converted to a dollar amount as follows:

1. Determine the total transportation cost.

$$\text{total volume transported} \times \text{transportation charge} \times \text{value per barrel} = \text{transportation cost}$$

$$40,000\text{ MMBtu} \times 0.05 \times \$2/\text{MMBtu} = \$4,000$$

2. Determine the transportation rate per unit.

$$\frac{\text{total transportation cost}}{\text{total volume transported}} = \text{transportation rate per MMBtu}$$

$$\frac{\$4{,}000}{40{,}000\ \text{MMBtu}} = \$0.10/\text{MMBtu}$$

6.6 Reporting and Recordkeeping Requirements

This section describes the reporting and recordkeeping requirements that MMS has established for gas transportation allowances. Gas transportation allowances are reported as a separate line item on Form MMS-2014 using transaction code 11 unless MMS approves a different reporting procedure.

After a PIF is submitted to MMS designating an individual as a royalty payor (not a rental payor), MMS preprints a Model Form MMS-2014. The Model Form MMS-2014 is sent monthly to the designated individual. The preprinted Model Form MMS-2014 contains allowance lines if an allowance form has been filed with MMS. If the allowance lines are not preprinted on the lessee's Model Form MMS-2014, then either:

- An appropriate allowance form has not been filed;
- Erroneous data were reported on the allowance form submitted to MMS; or
- The Model Form MMS-2014 was printed prior to MMS receiving the allowance form.

In the months in which the allowance lines do not preprint on the Model Form MMS-2014, the lessee needs to include these lines manually on its Model Form MMS-2014 before submitting it to MMS. If the allowance form is incorrect, the lessee should contact the Compliance Verification Division. See "Important Addresses and Phone Numbers" on page 1-5.

No prior approval is required to deduct a gas transportation allowance, provided the allowance does not exceed 50 percent of the value of the gas. However, an Indian lessee is required to file the appropriate forms before deducting any estimated or actual allowance on Form MMS-2014. A gas transportation allowance may be claimed retroactively on Indian leases for a period of not more than 3 months prior to the first day of the month that Form MMS-4295 is filed with MMS unless MMS approves a longer period upon a showing of good cause by the lessee. The elements that constitute good cause are determined on a case-by-case basis (see "Exception to 3-month retroactive limitation" on p. 6-66).

The following forms are used to report gas transportation allowances for Indian leases:

Form	Title
Form MMS-4295	
Page 1	Gas Transportation Allowance Report
Schedule 1	Gas Transportation Facility Summary Sheet
Schedule 1A	Non-Arm's-Length Transportation System/Segment Operations, Maintenance, and Overhead Expenditure
Supplemental Schedule 1A	Non-Arm's-Length Transportation System/Segment Operations, Maintenance, and Overhead Expenditures (continuation sheet)
Schedule 1B	Non-Arm's-Length Transportation System/Segment Depreciation and Capital Expenditure Summary
Schedule 1C	Allowance For Non-Arm's-Length Transportation of Gas Liquids and Sulfur from the Lease to the Gas Processing Plant

6.6.1 Arm's-length transportation contracts

For transportation costs incurred by the lessee under an arm's-length contract, the transportation allowance is the reasonable, actual costs incurred by the lessee for transporting unprocessed gas, residue gas, and/or gas plant products (including nitrogen, CO_2, sulfur, and helium) under that contract. In addition, the transportation allowance may include the reasonable, actual costs incurred by the lessee for transporting drip condensate and flash gas.

The lessee is obligated to market gas for the mutual benefit of the lessee and the lessor. MMS expects a lessee to be prudent in negotiating a transportation contract that reflects only reasonable, actual expenses necessary to transport gas to the nearest sales point. If MMS determines that the consideration paid under an arm's-length transportation contract does not reflect reasonable value because of misconduct or breach of duty by the lessee to market the production for the mutual benefit of the lessee and the lessor, or if the contract reflects more than the total consideration, MMS requires the lessee to determine the transportation costs based on the non-arm's-length or no-contract criteria (30 CFR §§ 206.157(a)(1)(iii), 206.177(a)(1)(iii), 206.157(a)(1)(ii), and 206.177(a)(1)(ii)).

The lessee has the burden of demonstrating that its contract is arm's-length. If necessary, MMS may require a lessee to submit its arm's-length transportation contracts, production and operating agreements, and related documents to demonstrate that the consideration paid reflects reasonable value. These documents must be submitted within a reasonable time as determined by MMS.

If a lessee has arm's-length contracts involving spot sales, variable rates, or any other situation where the allowance rate may vary from month to month, the lessee should report its actual costs every month on Form MMS-2014. The lessee should report a volume-weighted-average allowance rate on Form MMS-4295 for the applicable reporting period and indicate the type of contract (see "Instructions for Completing Form MMS-4295 for Arm's-Length Contracts—Indian Leases Only" on page 6-24).

For example, assume the lessee has 12 spot sales contracts for January 1 through December 31, 1990.

STEP 1. For each contract, compute the transportation cost for the period by multiplying the transportation charge by the volume transported.

Sales month/year	Transportation charge ($/MMBtu)	Volume transported (MMBtu)	Total contract cost
1/90	$0.26	1,000,000	$260,000
2/90	0.21	750,000	157,500
3/90	0.35	1,326,000	464,100
4/90	0.33	1,210,000	399,300
5/90	0.33	612,000	201,960
6/90	0.18	1,222,222	220,000
7/90	0.23	967,000	222,410
8/90	0.19	1,177,396	223,705
9/90	0.26	823,999	214,240
10/90	0.26	845,200	219,752
11/90	0.25	801,201	200,300
12/90	0.27	992,150	267,881
	Total	11,727,168	$3,051,148

STEP 2. Determine the volume-weighted-average allowance rate for the year by summing the total contract costs and dividing by the total volume transported under all contracts.

$$\frac{\$3{,}051{,}148}{11{,}727{,}168 \text{ MMBtu}} = \$0.260178/\text{MMBtu}$$

6.6.2 Non-Arm’s-length transportation contracts or no-contract situations

Transportation allowances for non-arm’s-length contracts or no-contract situations are based on the lessee’s actual costs for transporting lease gas during the reporting period.

The lessee's actual costs include operating, maintenance, and overhead expenses (combined operating and maintenance costs) and **either**:

- Depreciation and a return on undepreciated capital investment (depreciation method); or
- A return on the initial capital invested in the transportation system (ROI method).

Transportation allowances for facilities placed into service before March 1, 1988, can be computed by using only the depreciation method. Transportation allowances for facilities placed into service on or after March 1, 1988, can be computed by using either the depreciation method or the ROI method. After the lessee has elected to use either method to compute the allowance, the lessee may not later change to the other method without MMS approval.

The rate of return used in either the depreciation method or the ROI method is the monthly average industrial BBB bond rate published in the *Standard and Poor's Bond Guide* for the first month of the reporting period for which the allowance applies. This rate remains effective during the reporting period and is redetermined at the beginning of each subsequent reporting period.

MMS grants an exception from the requirement that the lessee compute actual costs for non-arm's-length contracts or no-contract situations only if the lessee has a tariff for the transportation system approved by FERC (for both Federal and Indian leases) or a State regulatory agency (for Federal leases). See "Exception to compute actual costs" on page 6-66 for more information.

The lessee must submit a request for the exception annually. If MMS approves the request, the lessee should follow the arm's-length reporting requirements.

6.6.2.1 Depreciation

If the lessee uses the depreciation method, depreciation is computed by either:

- Straight-line depreciation based on the reasonable life of the equipment or the reasonable life of the reserves, or
- Unit-of-production method.

After the lessee has elected one method to compute depreciation, the lessee may not later change to the other method without MMS approval. In addition, a change in ownership of the transportation facility does not alter the depreciation schedule established by the original lessee; a transportation facility or equipment can be depreciated only once. Equipment may not be depreciated below a reasonable salvage value without MMS approval.

If the lessee uses the ROI method, capital costs are computed by multiplying the allowable initial capital invested in the transportation system by the rate of return. Depreciation is not used with this method.

Allowable capital costs are those costs for depreciable fixed assets that are an integral part of the transportation system, including costs of delivery and installation. The allowable and nonallowable capital costs are described in detail in "Capital costs" on page 6-9.

6.6.2.2 Throughput

Transportation allowances are based on the total volumes transported through the transportation system during the reporting period.

6.6.2.3 Transportation system segments

A transportation facility is a physical system associated with the transportation of gas or gas products from the lease to a point of disposition remote from the lease. Where transportation systems consist of segments, cost rates are computed for each segment.

A transportation segment is any mode of transportation from one point to another for which the lessee can associate unique, identifiable costs. A transportation segment may be part of the total transportation facility, such as from one tie-in location to another on the pipeline, or may constitute the entire facility. Examples of a transportation segment would be an origin-to-destination pipeline owned by the lessee or truck haulage over specific routes where the equipment is owned by the lessee. An example of a multisegment transportation system would be a pipeline bringing sour gas to a processing facility and rail or truck haulage transporting sulfur from the processing plant to a remote point of sale.

6.7 Instructions for Completing Form MMS-4295 for Arm's-Length Contracts—Indian Leases Only

Lessees of Indian leases are required to file for an allowance prior to claiming that allowance on Form MMS-2014. The following sections provide instructions for completing Form MMS-4295 for arm's-length contracts.

For arm's-length contracts, the lessee must complete Page 1, Schedule 1, and Schedule 1C (if required) of Form MMS-4295.

NOTE

Fill out the forms in reverse order. For example, prepare Schedule 1 before filling out Page 1.

In the following instructions, wherever a dashed horizontal line occurs in an example, a portion of the form has been omitted to save space.

6.7.1 Gas Transportation Allowance Report (Page 1), Form MMS-4295 (arm's-length)

The Gas Transportation Allowance Report (Page 1), Form MMS-4295 (fig. 6-1), is used to report the actual royalty allowance amounts claimed during the prior reporting period and to estimate the royalty allowance amount for the current reporting period. Reporting is by AID number (13 digits), product code (2 digits), and selling arrangement (3 digits). Page 1 acts as a summary sheet for information on Schedules 1 and 1C of Form MMS-4295.

Complete Page 1 of Form MMS-4295 following the instructions presented below. Any deviation from these instructions may result in the lessee incurring either a payback bill or an interest bill.

NOTE

The examples provided do not necessarily relate directly to one another.

U.S. DEPARTMENT OF THE INTERIOR
Minerals Management Service
Royalty Management Program

GAS TRANSPORTATION ALLOWANCE REPORT

OMB NO. 1010-0075
Expires August 31, 20XX

FOR MMS USE ONLY:

1 PAYOR NAME ____________

ADDRESS ____________

CITY ____________ STATE ____________ ZIP ____________

2 PAYOR CODE

4 FEDERAL or INDIAN

5 REPORT TYPE

6 REPORTING PERIOD 19__ to 19__

3 FOR PAYOR USE ONLY:

7	8 ACCOUNTING IDENTIFICATION (AID) NUMBER	9 PRODUCT CODE	10 SELLING ARRANGEMENT CODE	11 ARM'S-LENGTH/ PAYOR-OWNED INDICATOR	12 PRIOR PERIOD ACTUAL DATA a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT	13 CURRENT PERIOD ESTIMATED DATA a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT
1										
2										
3										
4										
5										
6										
7										
8										
9										
10										
11										
12	PAGE TOTAL					xxxxxxxxxxxx			xxxxxxxxxxxx	
13	REPORT TOTAL (LAST PAGE ONLY)					xxxxxxxxxxxx			xxxxxxxxxxxx	

FOR ILLUSTRATION ONLY

IF MORE LINES ARE NEEDED, ATTACH ADDITIONAL PAGES OF FORM MMS-4295

I have read and examined the statements in this report and, to the best of my knowledge, they are accurate and complete.

NAME (FIRST, MIDDLE INITIAL, LAST) (typed or printed) 14 DATE:

AUTHORIZED SIGNATURE: DATE:

NAME OF PREPARER: TELEPHONE NUMBER:

WARNING: This is to inform you that failure to report accurately and timely in accordance with the statutes, regulations, or terms of the lease, permit, or contract may result in late payment charges, civil penalties, or liquidated damages being assessed without further notification. Intentional false or inaccurate reporting is subject to criminal prosecution in accordance with applicable Federal law(s).

THIS INFORMATION SHOULD BE CONSIDERED (Please check one) ☐ PROPRIETARY ☐ NONPROPRIETARY 15

FORM MMS-4295 (REV. 11/94)

The Paperwork Reduction Act of 1980 (44 U.S.C. 3501 et seq.) requires MMS to inform you that this information is being collected for the purpose of managing its gas transportation allowance program.

FIGURE 6-1. Gas Transportation Allowance Report (Page 1), Form MMS-4295

STEP 1. In field 1, Payor Name and Address, enter the payor name and address used to report royalties and transportation deductions on Form MMS-2014.

STEP 2. In field 2, Payor Code, enter the same payor code as used on Form MMS-2014.

Field 3, For Payor Use Only, is reserved for payor comment.

STEP 3. In field 4, Federal or Indian, check the Indian box to indicate the type of lease(s) covered by this report.

STEP 4. In field 5, Report Type, enter the report type indicator. The Gas Transportation Allowance Report is classified into three report types described as follows:

Report type 1 is used for initial reporting under the new regulations, reporting on newly acquired lease(s), or reporting estimates only. No **Prior Period Actual Data** are reported in column 12. Only the **Current Period Estimated Data** are reported in column 13.

U.S. DEPARTMENT OF THE INTERIOR
Minerals Management Service
Royalty Management Program

GAS TRANSPORTATION ALLOWANCE REPORT

OMB NO. 1010-0075
Expires August 31, 20XX

FOR MMS USE ONLY:

1 PAYOR NAME Bob Henry Oil Company
ADDRESS 101 Boardwalk
CITY Lakewood STATE CO ZIP 80228

2 PAYOR CODE 12345

4 FEDERAL [ ] or INDIAN [X]

5 REPORT TYPE 1

6 REPORTING PERIOD 01/01 19 90 to 12/31 19 90

3 FOR PAYOR USE ONLY:

7	8	9	10	11	12 PRIOR PERIOD ACTUAL DATA			13 CURRENT PERIOD ESTIMATED DATA		
	ACCOUNTING IDENTIFICATION (AID) NUMBER	PRODUCT CODE	SELLING ARRANGEMENT CODE	ARM'S-LENGTH/ PAYOR-OWNED INDICATOR	a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT	a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT
1	516-001234-0-001	04	001	6				10,000	0.15	1,500
2										
3										

STEP 4. ***(continued)***

Report type 2 is a routine report used to report the prior period actual data and the current period estimated data. Column 12 must be filled out. If there will be no future production, leave column 13 blank (do not use zeros). If future production is anticipated, complete column 13 with current period estimated data.

If the lessee reports current period estimated data in column 13, the automated system generates a reporting period beginning with the first day after the prior period actual data reporting period and continuing until the end of that calendar year.

U.S. DEPARTMENT OF THE INTERIOR
Minerals Management Service
Royalty Management Program

GAS TRANSPORTATION ALLOWANCE REPORT

OMB NO. 1010-0075
Expires August 31, 20XX

FOR MMS USE ONLY: Received 3/25/91

1 PAYOR NAME Bob Henry Oil Company
ADDRESS 101 Boardwalk
CITY Lakewood STATE CO ZIP 80228

2 PAYOR CODE 12345
4 FEDERAL or INDIAN X
5 REPORT TYPE 2
6 REPORTING PERIOD 01/01 19 90 to 12/31 19 90

3 FOR PAYOR USE ONLY:

7	8 ACCOUNTING IDENTIFICATION (AID) NUMBER	9 PRODUCT CODE	10 SELLING ARRANGEMENT CODE	11 ARM'S-LENGTH/ PAYOR-OWNED INDICATOR	12 PRIOR PERIOD ACTUAL DATA a ROYALTY QUANTITY	12 b ALLOWANCE RATE PER UNIT	12 c ROYALTY ALLOWANCE AMOUNT	13 CURRENT PERIOD ESTIMATED DATA a ROYALTY QUANTITY	13 b ALLOWANCE RATE PER UNIT	13 c ROYALTY ALLOWANCE AMOUNT
1	516-001234-0-001	04	001	6	15,000	0.15	2,250	20,000	0.15	3,000
2										
3										

Report type 3 is used to correct previously submitted reports and contains only one reporting period. Either column 12 or 13 must be completed, but not both. If correcting an initial report (report type 1), only one corrected Form MMS-4295 (report type 3) is required. If correcting a routine report (report type 2), two separate corrected reports (report type 3) are required: one to correct the prior period actual data in column 12 and one to correct the current period estimated data in column 13.

STEP 4. *(continued)*

Report type 3 is considered the most correct and current information. No minus signs are required to reverse the incorrect entry. However, if correcting the payor code, AID number, product code, or selling arrangement, place the correct data in the appropriate field(s) and indicate in field 3 (For Payor Use Only) the original filing date of the report.

NOTE

A payor code can be corrected only if it is one of the lessee's other valid codes. A lease number cannot be corrected. If a lease number was reported incorrectly, a new report type 1 or 2 must be submitted with the correct lease number. A revenue source, product code, and/or selling arrangement may be corrected.

To correct the prior period actual data, complete column 12 only. Use the period indicative of the prior period actual data as the reporting period shown in field 6, Reporting Period.

U.S. DEPARTMENT OF THE INTERIOR
Minerals Management Service
Royalty Management Program

GAS TRANSPORTATION ALLOWANCE REPORT

OMB NO. 1010-0075
Expires August 31, 20XX

FOR MMS USE ONLY:

1 PAYOR NAME Bob Henry Oil Company

ADDRESS 101 Boardwalk

CITY Lakewood STATE CO ZIP 80228

2 PAYOR CODE 12345

4 FEDERAL or INDIAN X

5 REPORT TYPE 3

6 REPORTING PERIOD 01/01 19 90 to 12/31 19 90

3 FOR PAYOR USE ONLY: 03/25/91

7	8 ACCOUNTING IDENTIFICATION (AID) NUMBER	9 PRODUCT CODE	10 SELLING ARRANGEMENT CODE	11 ARM'S-LENGTH/ PAYOR-OWNED INDICATOR	12 PRIOR PERIOD ACTUAL DATA a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT	13 CURRENT PERIOD ESTIMATED DATA a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT
1	516-001234-0-001	04	001	6	15,000	0.12	1,800			
2										
3										

STEP 4. ***(continued)***

To correct the current period estimated data, complete column 13 only. Use the period reflective of the current period estimated data as the reporting period shown in field 6.

U.S. DEPARTMENT OF THE INTERIOR
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Royalty Management Program

GAS TRANSPORTATION ALLOWANCE REPORT

OMB NO. 1010-0075
Expires August 31, 20XX

FOR MMS USE ONLY:

1 PAYOR NAME Bob Henry Oil Company

2 PAYOR CODE 12345

ADDRESS 101 Boardwalk

4 FEDERAL or INDIAN X

CITY Lakewood STATE CO ZIP 80228

5 REPORT TYPE 3

6 REPORTING PERIOD 01/01 19 90 to 12/31 19 90

3 FOR PAYOR USE ONLY: 03/25/91

7	8 ACCOUNTING IDENTIFICATION (AID) NUMBER	9 PRODUCT CODE	10 SELLING ARRANGEMENT CODE	11 ARM'S-LENGTH/ PAYOR-OWNED INDICATOR	12 PRIOR PERIOD ACTUAL DATA a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT	13 CURRENT PERIOD ESTIMATED DATA a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT
1	516-001234-0-001	04	001	6				20,000	0.12	2,400
2										
3										

Shown below are examples of Form MMS-4295 with an incorrect selling arrangement (report type 2) and the corrected reports (report type 3) required to correct the error. The same procedures are required to correct the revenue source and/or product code except that the correct data are reported in the corresponding Accounting Identification (AID) Number (column 8) and/or Product Code (column 9) column.

In the examples shown below, the lessee correctly reported selling arrangement code 001 on its Form MMS-2014, but inadvertently reported selling arrangement code 002 on its Form MMS-4295 (report type 2).

STEP 4. ***(continued)***

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Minerals Management Service
Royalty Management Program

GAS TRANSPORTATION ALLOWANCE REPORT

OMB NO. 1010-0075
Expires August 31, 20XX

FOR MMS USE ONLY:

1 PAYOR NAME Bob Henry Oil Company
ADDRESS 101 Boardwalk
CITY Lakewood STATE CO ZIP 80228

2 PAYOR CODE 12345
4 FEDERAL or INDIAN X (INDIAN)
5 REPORT TYPE 2
6 REPORTING PERIOD 01/01 19 90 to 12/31 19 90

3 FOR PAYOR USE ONLY:

7	8 ACCOUNTING IDENTIFICATION (AID) NUMBER	9 PRODUCT CODE	10 SELLING ARRANGEMENT CODE	11 ARM'S-LENGTH/ PAYOR-OWNED INDICATOR	12 PRIOR PERIOD ACTUAL DATA a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT	13 CURRENT PERIOD ESTIMATED DATA a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT
1	516-001234-0-001	04	002	6	15,000	0.15	2,250	20,000	0.15	3,000
2										
3										

The lessee then submits two separate corrected Forms MMS-4295 (report type 3) to show the correct selling arrangement code of 001 for both the prior period actual data and the current period estimated data.

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GAS TRANSPORTATION ALLOWANCE REPORT

OMB NO. 1010-0075
Expires August 31, 20XX

FOR MMS USE ONLY:

1 PAYOR NAME Bob Henry Oil Company
ADDRESS 101 Boardwalk
CITY Lakewood STATE CO ZIP 80228

2 PAYOR CODE 12345
4 FEDERAL or INDIAN X (INDIAN)
5 REPORT TYPE 3
6 REPORTING PERIOD 01/01 19 90 to 12/31 19 90

3 FOR PAYOR USE ONLY: 03/21/91

7	8 ACCOUNTING IDENTIFICATION (AID) NUMBER	9 PRODUCT CODE	10 SELLING ARRANGEMENT CODE	11 ARM'S-LENGTH/ PAYOR-OWNED INDICATOR	12 PRIOR PERIOD ACTUAL DATA a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT	13 CURRENT PERIOD ESTIMATED DATA a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT
1	516-001234-0-001	04	001	6	15,000	0.15	2,250			
2										
3										

STEP 4. ***(continued)***

U.S. DEPARTMENT OF THE INTERIOR
Minerals Management Service
Royalty Management Program

GAS TRANSPORTATION ALLOWANCE REPORT

OMB NO. 1010-0075
Expires August 31, 20XX

FOR MMS USE ONLY:

1 PAYOR NAME Bob Henry Oil Company
ADDRESS 101 Boardwalk
CITY Lakewood STATE CO ZIP 80228

2 PAYOR CODE 12345
4 FEDERAL or INDIAN [ ] FEDERAL [X] INDIAN
5 REPORT TYPE 3
6 REPORTING PERIOD 01/01 19 90 to 12/31 19 90

3 FOR PAYOR USE ONLY: 03/25/91

7	8 ACCOUNTING IDENTIFICATION (AID) NUMBER	9 PRODUCT CODE	10 SELLING ARRANGEMENT CODE	11 ARM'S-LENGTH/ PAYOR-OWNED INDICATOR	12 PRIOR PERIOD ACTUAL DATA a ROYALTY QUANTITY	12 b ALLOWANCE RATE PER UNIT	12 c ROYALTY ALLOWANCE AMOUNT	13 CURRENT PERIOD ESTIMATED DATA a ROYALTY QUANTITY	13 b ALLOWANCE RATE PER UNIT	13 c ROYALTY ALLOWANCE AMOUNT
1	516-001234-0-001	04	001	6				20,000	0.15	3,000
2										
3										

STEP 5. In field 6, enter the reporting period for the report type selected as defined below.

NOTE

The reporting period shown for Form MMS-4295 must correspond to the specific **sales** month reported on Form MMS-2014.

Reporting period for a report type 1. A report type 1 indicates that the lessee is reporting only Current Period Estimated Data (column 13). Therefore, the reporting period reflects the current period estimated data.

STEP 5. *(continued)*

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GAS TRANSPORTATION ALLOWANCE REPORT

OMB NO. 1010-0075
Expires August 31, 20XX

FOR MMS USE ONLY:

1 PAYOR NAME Bob Henry Oil Company
ADDRESS 101 Boardwalk
CITY Lakewood STATE CO ZIP 80228

2 PAYOR CODE 12345
4 FEDERAL or INDIAN: X (INDIAN)
5 REPORT TYPE 1
6 REPORTING PERIOD 01/01 19 90 to 12/31 19 90

3 FOR PAYOR USE ONLY:

7	8 ACCOUNTING IDENTIFICATION (AID) NUMBER	9 PRODUCT CODE	10 SELLING ARRANGEMENT CODE	11 ARM'S-LENGTH/ PAYOR-OWNED INDICATOR	12 PRIOR PERIOD ACTUAL DATA			13 CURRENT PERIOD ESTIMATED DATA		
					a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT	a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT
1	516-001234-0-001	04	001	6				10,000	0.15	1,500
2										
3										

Reporting period for a report type 2. A report type 2 indicates that the lessee is reporting prior period actual data (column 12). The lessee may or may not report current period estimated data (column 13) depending on the anticipation of production. Therefore, the reporting period on a report type 2 always reflects the prior period actual data (column 12). If the lessee reports current period estimated data (column 13), the automated system generates a reporting period beginning with the first day following the prior period actual data reporting period and continuing until the end of that calendar year.

STEP 5. ***(continued)***

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GAS TRANSPORTATION ALLOWANCE REPORT

OMB NO. 1010-0075
Expires August 31, 20XX

FOR MMS USE ONLY:

1 PAYOR NAME Bob Henry Oil Company
2 PAYOR CODE 12345
ADDRESS 101 Boardwalk
4 FEDERAL or INDIAN: X (INDIAN)
CITY Lakewood STATE CO ZIP 80228
5 REPORT TYPE 2
6 REPORTING PERIOD 01/01 19 90 to 12/31 19 90
3 FOR PAYOR USE ONLY:

7	8 ACCOUNTING IDENTIFICATION (AID) NUMBER	9 PRODUCT CODE	10 SELLING ARRANGEMENT CODE	11 ARM'S-LENGTH/ PAYOR-OWNED INDICATOR	12 PRIOR PERIOD ACTUAL DATA a ROYALTY QUANTITY	12 b ALLOWANCE RATE PER UNIT	12 c ROYALTY ALLOWANCE AMOUNT	13 CURRENT PERIOD ESTIMATED DATA a ROYALTY QUANTITY	13 b ALLOWANCE RATE PER UNIT	13 c ROYALTY ALLOWANCE AMOUNT
1	516-001234-0-001	04	001	6	15,000	.015	2,250	20,000	0.15	3,000
2										
3										

Reporting period for a report type 3. A report type 3 indicates that the lessee is correcting previously submitted data for a specific reporting period. The lessee should fill out only column 12 to correct prior period actual data.

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GAS TRANSPORTATION ALLOWANCE REPORT

OMB NO. 1010-0075
Expires August 31, 20XX

FOR MMS USE ONLY:

1 PAYOR NAME Bob Henry Oil Company
2 PAYOR CODE 12345
ADDRESS 101 Boardwalk
4 FEDERAL or INDIAN: X (INDIAN)
CITY Lakewood STATE CO ZIP 80228
5 REPORT TYPE 3
6 REPORTING PERIOD 01/01 19 90 to 12/31 19 90
3 FOR PAYOR USE ONLY: 3/25/91

7	8 ACCOUNTING IDENTIFICATION (AID) NUMBER	9 PRODUCT CODE	10 SELLING ARRANGEMENT CODE	11 ARM'S-LENGTH/ PAYOR-OWNED INDICATOR	12 PRIOR PERIOD ACTUAL DATA a ROYALTY QUANTITY	12 b ALLOWANCE RATE PER UNIT	12 c ROYALTY ALLOWANCE AMOUNT	13 CURRENT PERIOD ESTIMATED DATA a ROYALTY QUANTITY	13 b ALLOWANCE RATE PER UNIT	13 c ROYALTY ALLOWANCE AMOUNT
1	516-001234-0-001	04	001	6	15,000	0.12	1,800			
2										
3										

STEP 5. ***(continued)***

The lessee should fill in only column 13 to correct current period estimated data. Prior period actual data (column 12) must not be filled out.

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Royalty Management Program

GAS TRANSPORTATION ALLOWANCE REPORT

OMB NO. 1010-0075
Expires August 31, 20XX

FOR MMS USE ONLY:

1 PAYOR NAME Bob Henry Oil Company

ADDRESS 101 Boardwalk

CITY Lakewood STATE CO ZIP 80228

2 PAYOR CODE 12345

4 FEDERAL or INDIAN X

5 REPORT TYPE 3

6 REPORTING PERIOD 01/01 19 90 to 12/31 19 90

3 FOR PAYOR USE ONLY: 3/25/91

7	8	9	10	11	12 PRIOR PERIOD ACTUAL DATA			13 CURRENT PERIOD ESTIMATED DATA		
	ACCOUNTING IDENTIFICATION (AID) NUMBER	PRODUCT CODE	SELLING ARRANGEMENT CODE	ARM'S-LENGTH/ PAYOR-OWNED INDICATOR	a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT	a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT
1	516-001234-0-001	04	001	6				20,000	0.12	2,400
2										
3										

Column 7 is a line count; that is, it identifies the number of allowances being reported.

STEP 6. In column 8, Accounting Identification Number, enter the same AID number as used on Form MMS-2014 for each allowance.

STEP 7. In column 9, Product Code, enter the same product code as used on Form MMS-2014.

STEP 8. In column 10, Selling Arrangement Code, enter the same selling arrangement code as used on Form MMS-2014.

STEP 9. In column 11, Arm's-Length/Payor-Owned Indicator, enter an arm's-length indicator as follows:

- Enter indicator **5** if transportation costs were incurred under a combination of arm's-length and non-arm's-length conditions.
- Enter indicator **6** if 100 percent of the transportation costs were incurred under arm's-length conditions.

STEP 10. Column 12, Prior Period Actual Data, is used to report actual cost data for the reporting period.

NOTE

If this is an initial report, a report for newly acquired leases, or a report for estimates (no actual data are reported), do not complete column 12. Instead, go to the instructions for column 13.

In column 12a, Royalty Quantity, enter the total royalty quantity transported during the reporting period. Total royalty quantity is the sum of the monthly royalty quantities reported on Form MMS-2014, field 17, for a specific selling arrangement. Decimals are not required in this column.

In column 12b, Allowance Rate Per Unit, enter the transportation allowance rate from Schedule 1 of Form MMS-4295, line 16. The rate in column 12b is computed to six decimals; however, zeros may be dropped.

NOTE

The actual allowance rate cannot exceed 50 percent of the unit value of the gas or gas product (unless MMS has approved a rate in excess of 50 percent).

In column 12c, Royalty Allowance Amount, enter the royalty allowance amount, computed by multiplying column 12a by 12b. Decimals are not required in column 12c.

STEP 11. Column 13, Current Period Estimated Data, is used to report an initial allowance under the new regulations, newly acquired leases, or estimates (no actual data are reported).

If an allowance was reported for the prior period, the transportation quantity or allowance rate may be the same as the actual quantity or allowance rate reported in column 12. If these are the same, enter the corresponding values from columns 12a, 12b, and 12c into columns 13a, 13b, and 13c, respectively. If the lessee believes the quantity or the rate for the current reporting period will differ from the prior reporting period, the estimates should be adjusted upward or downward.

Estimates should be as accurate as possible and should not exceed 50 percent of the expected royalty value without prior MMS approval. Overestimating on Form MMS-2014 will result in a royalty underpayment.

In column 13a, Royalty Quantity, enter the total estimated royalty quantity to be transported during the current reporting period. Total royalty quantity is the sum of the monthly royalty quantities to be reported for a specific selling arrangement. Decimals are not required in this column.

In column 13b, Allowance Rate Per Unit, for **fully arm's-length conditions**, enter the allowance rate specified in the arm's-length contract and shown on Schedule 1, line 16. For a **combination of arm's-length and non-arm's-length conditions**, use Schedules 1, 1A, 1B, and 1C (if appropriate) to estimate the allowance rate. The rate in field 13b is computed to six decimals; however, zeros may be dropped.

NOTE

The estimated allowance rate cannot exceed 50 percent of the value of the gas or gas product (unless MMS has approved a rate in excess of 50 percent).

In column 13c, Royalty Allowance Amount, enter the estimated royalty allowance amount, computed by multiplying column 13a by 13b. Decimals are not required in column 13c.

STEP 12. Enter page totals on line 12. If more than one Page 1 of Form MMS-4295 is submitted, subtotal the amount on line 12 for each page and enter the total only once on line 13 of the last page.

STEP 13. In column 14, enter the name of the person authorized to sign the allowance form and the current date. The authorized person must then sign and date the form. Enter the name and telephone number of the person who prepared the form.

STEP 14. At field 15, check the appropriate box to indicate whether the information is proprietary or nonproprietary.

6.7.2 Schedule 1—Gas Transportation Facility Summary Sheet, Form MMS-4295 (arm's-length)

Schedule 1—Gas Transportation Facility Summary Sheet, Form MMS-4295 (fig. 6-2), is used to accumulate segment costs and compute the royalty allowance rate for a transportation facility. A separate Schedule 1 must be completed for each unique AID number, product code, and selling arrangement combination. No allowance may be claimed if the facility is on the lease site.

Part A is used to accumulate segment costs and compute an allowance for transporting gas or gas products from the lease to a processing facility off the lease. Part B is used to accumulate segment costs and compute an allowance for transporting gas or gas products from either a lease or a processing facility to the nearest available marketplace or sales outlet off the lease.

The following instructions apply to both parts A and B. Lessees may need to complete part A, part B, or both. For simplicity, most of the following examples show only part B.

If entrained products, including NGLs, sulfur, CO_2, helium, and nitrogen, are present in the gas stream, the lessee must first complete Schedule 1C—Allowance for Non-Arm's-Length Transportation of Gas Liquids and Sulfur (fig. 6-3, p. 6-42). The transportation rate computed on Schedule 1C is then used to complete parts A and B of Schedule 1.

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SCHEDULE 1 -- GAS TRANSPORTATION FACILITY SUMMARY SHEET

[1] PAYOR NAME AND CODE ______ / ______

ADDRESS ______

CITY ______ STATE ______ ZIP ______

[2] ACCOUNTING ID NUMBER: ______

SELLING ARRANGEMENT CODE: ______

FACILITY NAME/ID NUMBER: ______

PRODUCT CODE: ______

PERIOD: 19 to 19

(a) Segment Name or Number		(b) Mode of Transportation	(c) Arm's-Length/ Payor-Owned Indicator	(d) Arm's-Length Contract/ Payor-Owned Operating Costs	(e) Depreciation	(f) Rate of Return	(g) Undepreciated Capital Investment at Beginning of Year	(h) Return on Investment (f) x (g)	
From	To								
A. TRANSPORTING GAS TO A REMOTE GAS PROCESSING FACILITY.									
				$	$		$	$	3
									4
									5
									6
									7
			Totals	$	$			$	8

Allowance rate = (lines 8d + 8e + 8h)/Quantity of production transported from the lease to the gas processing facility. ______ Part A Total Cost ÷ ______ Part A Total Quantity = $ ______ Gas Rate/Mcf [9]

Allowance rate for transporting NGL's or Sulfur from the lease to plant. ______ Sulfur Rate/LT ______ NGL Rate/Gal [10]

(a)		(b)	(c)	(d)	(e)	(f)	(g)	(h)	
B. TRANSPORTING GAS OR GAS PRODUCTS FROM LEASE OR PLANT TO A REMOTE SALES POINT.									
				$	$		$	$	11
									12
									13
			Totals	$	$			$	14

Allowance rate = (lines 14d + 14e + 14h)/Quantity of products. ______ Part B Total Cost ÷ ______ Part B Total Quantity = $ ______ Product Rate [15]

Total Unit Allowance Rate = the sum of line 9h and 15h if the allowance is for gas; line 10g and 15h if the allowance is for sulfur; or 10h and 15h if the allowance is for NGL's. The allowance rate cannot exceed 50 percent of the value of the product without prior MMS approval. ______ Allowance Rate [16]

THIS INFORMATION SHOULD BE CONSIDERED (Please check one) ☐ PROPRIETARY ☐ NONPROPRIETARY

FORM MMS-4295 SCHEDULE 1 (REV. 1/88)

FIGURE 6-2. Schedule 1—Gas Transportation Facility Summary Sheet, Form MMS-4295

When unprocessed gas is transported to a processing facility and processed, and then residue gas and gas plant products are transported from the facility to a remote sales point, both parts A and B of Schedule 1 must be used to compute the allowance.

Complete Schedule 1 of Form MMS-4295 as follows:

STEP 1. In field 1, enter the same payor name, payor code, and address as shown on Form MMS-2014.

STEP 2. In field 2, enter the same AID number and selling arrangement code as used on Form MMS-2014. Enter the unique transportation facility name or identification number designated by the payor. If a transportation facility consists of only one segment, the segment name or number is the same as the facility name or number. Enter the product code for which an allowance is being claimed. Enter the reporting period. The period will be the same as shown in field 6 on Page 1 of Form MMS-4295.

STEP 3. In column a, Segment Name or Number, describe each segment of the transportation facility; for example, from the lease to the Apache treatment facility.

STEP 4. In column b, Mode of Transportation, identify the mode of transportation under which costs are incurred; for example, pipeline, truck, rail, tanker, or barge.

STEP 5. In column c, Arm's-Length/Payor-Owned Indicator, indicate how facility/segment costs were incurred:

- Enter indicator **4** to denote payor-owned costs, which include non-arm's-length and no-contract situations.
- Enter indicator **6** to denote arm's-length contract costs

NOTE

When the indicator in column 11 (Arm's-Length/Payor-Owned Indicator) on Page 1 of Form MMS-4295 is a **5**, enter both **4** and **6** when completing column c on Schedule 1.

STEP 6. If transportation costs were incurred under an arm's-length contract, enter in column d, Arm's-Length Contract/Payor-Owned Operating Costs, the total costs incurred for the period. These costs are computed by multiplying the transportation rate by the quantity transported at that contract rate. Without prior MMS approval, a transportation allowance may not be taken for non-royalty-bearing substances.

NOTE

If two or more rates are applicable during the reporting period, the cost incurred under each rate must be computed and summed. For example, if the rate is \$0.10/MMBtu for 1,500 MMBtu and \$0.20/MMBtu for 1,000 MMBtu, the transportation costs would be:

$$(\$0.10/\text{MMBtu} \times 1{,}500 \text{ MMBtu}) + (\$0.20/\text{MMBtu} \times 1{,}000 \text{ MMBtu}) = \$350$$

Do **not** complete columns e through h for arm's-length costs.

STEP 7. Total column d and enter the amount(s) on line 8d and/or line 14d.

STEP 8. Enter the amount from line 8d and/or line 14d on line 9 and/or line 15, Total Cost.

Enter the total quantity of production transported on line 9 and/or line 15, Total Quantity. The total quantity is the sum of sales quantities reported on Form MMS-2014 for the reporting period.

NOTE

The total throughput quantity, excluding waste products that have no value, must be used.

STEP 9. Divide line 9 and/or line 15 Total Cost by line 9 and/or line 15 Total Quantity to compute the gas rate/Mcf (Part A) or product rate (Part B). Compute this figure to 6 decimals (zeros may be dropped). Enter the amount on line 9h and/or line 15h.

NOTE To determine an allowance for transporting sulfur or gas plant products, first complete Schedule 1C.

STEP 10. Enter on line 16 the total unit allowance rate, equal to the sum of:

- Line 9h plus line 15h if the product is gas,
- Line 10g plus line 15h if the product is sulfur, or
- Line 10h plus line 15h if the product is an NGL.

STEP 11. Enter the allowance rate from line 16 to column 12b or 13b on Page 1, whichever is applicable.

STEP 12. Check the appropriate box to indicate whether the information is proprietary or nonproprietary.

6.7.3 Schedule 1C—Allowance for Non-Arm's-Length Transportation of Gas Liquids and Sulfur from the Lease to the Gas Processing Plant, Form MMS-4295 (arm's-length)

Schedule 1C—Allowance for Non-Arm's-Length Transportation of Gas Liquids and Sulfur from the Lease to the Gas Processing Plant, Form MMS-4295 (fig. 6-3), is used to determine an allowance for transporting NGLs or sulfur from a **lease** to a processing facility in arm's-length situations.

Schedule 1C must be submitted with Page 1 and Schedule 1 of Form MMS-4295. No allowance may be claimed if the facility is on the lease site.

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SCHEDULE 1C -- ALLOWANCE FOR NON-ARM'S-LENGTH TRANSPORTATION OF GAS LIQUIDS AND SULFUR FROM THE LEASE TO THE GAS PROCESSING PLANT

PAYOR IDENTIFICATION BLOCK			
Payor Name and Code:			
Accounting ID No:			
Selling Arrangement Code:			
Facility ID No:			
Segment ID No:			
Period:	19	to	19

Liquids

(a) Product	(b) Gallons of Liquids Sold	(c1) Volume 1/ Factors Mcf/Gallon (14.73 psia)	(c2) Volume 1/ Factors Mcf/Gallon (15.025 psia)	(d) Volume of Liquids in Mcf (b)x(c)	(e) Allowance per Mcf (Line 9h Schedule 1)	(f) Product Allowance (d)x(e)	
Ethane		0.039608				$	1
Propane		0.036416					2
Isobutane		0.030829					3
N-butane		0.031527					4
Pentanes		0.027437					5
Hexane		0.024244					6
Heptane		0.021550					7
Pentanes and Heavier		0.024044					8
Other							9
Other							10
Totals						$	11
				Allowance Rate/Gallon (line 11f line 11b)		$	12

Sulfur

(a) Tons of Sulfur Sold	(b) Plant 2/ Recovery Factor	(c) Tons of Sulfur in Gas Stream (a)÷(b)	(d) Volume (Mcf) 3/ of H_2S in Gas Stream (c) x 26.207682	(e) Allowance per Mcf (line 9h Schedule 1)	(f) Sulfur Allowance (d x e)÷ a	
					$	13

1/ Petroleum Refinery Engineering, Fourth Edition, McGraw Hill (1958).

2/ To be based on actual plant sulfur recovery experience.

3/ Based upon PV = ZNRT Mcf at 60^{o}F, 14.73 psia, 94.08467 Wt% S in H_2S.
For Gulf of Mexico leases use a volume factor of 25.693121

THIS INFORMATION SHOULD BE CONSIDERED (Please check one) ☐ PROPRIETARY ☐ NONPROPRIETARY

FORM MMS-4295 SCHEDULE 1C (REV. 1/88)

FIGURE 6-3. Schedule 1C—Allowance for Non-Arm's-Length Transportation of Gas Liquids and Sulfur from the Lease to the Gas Processing Plant, Form MMS-4295

Complete Schedule 1C of Form MMS-4295 as follows:

STEP 1. Complete payor identification information (payor name and code, accounting ID number, selling arrangement code, facility ID number, segment ID number, and period) following Schedule 1 instructions.

Liquids section:

At the Liquids section, compute the transportation allowance rate for liquids as follows:

STEP 2. Column a, Product, lists liquid products that may be produced. In column b, Gallons of Liquids Sold, enter gallons of actual liquids produced.

STEP 3. Use column c1, volume factor 14.73 psia. If the volume factor used by the lessee is other than that listed, attach a list of the volume factors used, and refer to the scientific source from which these factors were taken.

STEP 4. Compute the volume of liquids in Mcf by multiplying column b by column c1. Enter the amount(s) in column d, Volume of Liquids in Mcf.

STEP 5. Enter the allowance per Mcf from line 9h, Schedule 1, in column e, Allowance per Mcf. (A value of $0.13/Mcf is used here for illustration.)

STEP 6. Compute the product allowance by multiplying column d by column e. Enter the amount(s) in column f, Product Allowance.

STEP 7. Sum column b and column f, and enter the totals on lines 11b and 11f, respectively. For liquids, compute the allowance rate to six decimals (ending zeros may be dropped) by dividing the total allowance (line 11f) by the total volume of liquids sold (line 11b). Enter the amount on line 12 of Schedule 1C and line 10h of Schedule 1.

Sulfur section:

At the Sulfur section, compute the transportation allowance rate for sulfur as follows:

STEP 8. In column a, Tons of Sulfur Sold, enter the total volume of sulfur (in long tons) sold during the reporting period.

STEP 9. In column b, Plant Recovery Factor, enter the sulfur recovery factor for the plant. This is based on actual plant sulfur recovery experience.

STEP 10. Compute the tons of sulfur in the gas stream by dividing column a by column b. Enter the amount in column c, Tons of Sulfur in Gas Stream.

STEP 11. In column d, Volume of H_2S in Gas Stream, enter the volume (Mcf) of hydrogen sulfide (H_2S) in the gas stream. This volume is determined by multiplying column c by the conversion factor 26.207682. If the lessee uses a conversion factor other than that listed, attach an explanation of the factor used and refer to the scientific source from which the factor was taken.

STEP 12. In column e, Allowance per Mcf, enter the transportation rate for transporting gas from the **lease** to the plant from line 9h, Schedule 1.

STEP 13. Compute the sulfur allowance rate per ton to six decimal places (ending zeros may be dropped) by multiplying column d by column e and then dividing that product by column a. Enter the amount in column f, Sulfur Allowance.

STEP 14. Enter the sulfur allowance rate per ton (line 13f) on line 10g of Schedule 1.

STEP 15. At the bottom of Schedule 1C, check the appropriate box to indicate whether the information is proprietary or nonproprietary.

6.8 Instructions for Completing Form MMS-4295 for Non-Arm's-Length Contracts or No-Contract Situations—Indian Leases Only

Lessees of Indian leases are required to file for an allowance prior to claiming that allowance on Form MMS-2014. The following sections provide instructions for completing Form MMS-4295 for non-arm's-length contracts or no-contract situations.

For non-arm's-length contracts or no-contract situations, the lessee must complete Page 1, Schedule 1, Schedule 1A, Supplemental Schedule 1A (if necessary), Schedule 1B, and Schedule 1C (as appropriate) of Form MMS-4295.

NOTE Fill out the forms in reverse order. For example, prepare Schedule 1C before filling out Schedule 1.

6.8.1 Gas Transportation Allowance Report (Page 1), Form MMS-4295 (non-arm's-length or no-contract)

The Gas Transportation Allowance Report (Page 1), Form MMS-4295 (fig. 6-1, p. 6-25), is used to report actual royalty allowance amounts claimed during the prior reporting period and to estimate the royalty allowance amount for the current reporting period. Reporting is by AID number (13 digits), product code (2 digits), and selling arrangement (3 digits).

Page 1 acts as a summary sheet for information contained on the schedules of Form MMS-4295. Refer to "Gas Transportation Allowance Report (Page 1), Form MMS-4295 (arm's-length)" on page 6-24 for instructions for completing Page 1.

6.8.2 Schedule 1—Gas Transportation Facility Summary Sheet, Form MMS-4295 (non-arm's-length or no-contract)

Schedule 1—Gas Transportation Facility Summary Sheet, Form MMS-4295 (fig. 6-2, p. 6-38), is used to accumulate segment costs and compute the royalty allowance rate for a transportation facility. A separate Schedule 1 must be completed for each unique AID number, product code, and selling arrangement combination. No allowance may be claimed if the facility is on the lease site.

Part A is used to accumulate segment costs and compute an allowance for transporting gas or gas products from the lease to a processing facility off the lease. Part B is used to accumulate segment costs and compute an allowance for transporting gas or gas products from either a lease or a processing facility to the nearest available marketplace or sales outlet off the lease.

If entrained products, including NGLs, sulfur, CO_2, helium, and nitrogen, are present in the gas stream, the lessee must first complete Schedule 1C—Allowance for Non-Arm's-Length Transportation of Gas Liquids and Sulfur. The transportation rate computed on Schedule 1C is then used to complete parts A and B of Schedule 1.

When unprocessed gas is transported to a processing facility and processed, and then residue gas and gas plant products are transported from the facility to a remote sales point, use both parts A and B of Schedule 1 to compute the allowance.

Information from Schedules 1A and 1B of Form MMS-4295 must also be used to complete Schedule 1.

Instructions for completing Schedule 1 of Form MMS-4295 follow. Also refer to "Schedule 1—Gas Transportation Facility Summary Sheet, Form MMS-4295 (arm's-length)" on page 6-37 for examples.

STEP 1. In field 1, enter the same payor name, payor code, and address as shown on Form MMS-2014.

STEP 2. In field 2, enter the same AID number and selling arrangement code as used on Form MMS-2014.

Enter the unique transportation facility name or identification number designated by the payor. If a transportation facility consists of only one segment, the segment name or ID number is the same as the facility name or ID number.

Enter the product code for which an allowance is being claimed.

Enter the reporting period. The period will be the same as shown in field 6 on Page 1 of Form MMS-4295.

The following instructions apply to both parts A, Transporting Gas to a Remote Gas Processing Facility, and B, Transporting Gas or Gas Products from Lease or Plant to a Remote Sales Point. Lessees may need to complete part A, part B, or both.

STEP 3. In column a, Segment Name or Number, describe each segment of the transportation facility; for example, from the lease to the Apache treatment facility.

STEP 4. In column b, Mode of Transportation, identify the mode of transportation under which costs are incurred; for example, pipeline, truck, rail, tanker, or barge.

STEP 5. In column c, Arm's-Length/Payor-Owned Indicator, indicate how facility/segment costs were incurred:

- Use indicator **4** to denote payor-owned costs, which include non-arm's-length and no-contract situations.
- Use indicator **6** to denote arm's-length contract costs.

NOTE When the indicator in column 11 (Arm's-Length/Payor-Owned Indicator) on Page 1 of Form MMS-4295 is a **5**, enter both **4** and **6** when completing column c on Schedule 1.

STEP 6. If transportation costs were incurred under other than arm's-length conditions, complete columns d through h. Use Schedule 1A to compute the operating, maintenance, and overhead expenditures. Enter the sum in column d on Schedule 1. A separate Schedule 1A must be completed for each individual segment.

STEP 7. In column e, Depreciation, enter depreciation costs for the reporting period. Schedule 1B must be used to determine depreciation costs.

NOTE

If a lessee is reporting for only 6 months of the year or the pipeline has been in service for only 6 months, the lessee must adjust the depreciation expense for the portion of the year in which the expense applies. For example, if the depreciable base is $2,000,000 and the estimated life is 20 years, the depreciation expense per year is $100,000. The depreciation expense for 6 months would be calculated as follows:

$$\text{Depreciation} = \$100{,}000 \times \frac{6}{12} = \$50{,}000$$

STEP 8. The rate of return is the industrial rate associated with Standard and Poor's BBB rating. In column f, Rate of Return, enter the monthly average as published in *Standard and Poor's Bond Guide* for the first month of the reporting period.

STEP 9. Using Schedule 1B, sum the Salvage Value **and** the Undepreciated Capital Investment at Beginning of Year. The salvage value must be allocated proportionately to each segment by multiplying it by the Allocated to Segment amount from Schedule 1B, line 9. Enter this total in column g on Schedule 1. A separate Schedule 1B must be completed for each individual segment.

NOTE

The amount in column g, Undepreciated Capital Investment at Beginning of Year, **must** include salvage value; otherwise, the next calculation (Return on Investment) will be incorrect.

STEP 10. Calculate the ROI by multiplying column f by column g. Enter this amount in column h.

NOTE

If a lessee is reporting for only 6 months of the year or the pipeline has been in service for only 6 months, the lessee must adjust for the partial year. For example, if the undepreciated investment at the beginning of the year is \$250,000, and the industrial BBB bond rate is 10 percent, the ROI is calculated as follows:

$$\text{ROI} = \$250{,}000 \times \left(10\% \times \frac{6}{12}\right) = \$12{,}500$$

STEP 11. Total columns d, e, and h. Enter the amounts on lines 8d, 8e, and 8h for part A, and/or lines 14d, 14e, and 14h for part B.

STEP 12. Add the amounts in lines 8d, 8e, and 8h and/or lines 14d, 14e, and 14h, and enter the total on line 9 and/or line 15 Total Cost.

STEP 13. Enter the total quantity of production transported on line 9 and/or line 15 Total Quantity.

NOTE

Total throughput quantity, excluding waste products that have no value, must be used.

STEP 14. Divide line 9 and/or line 15 Total Cost by line 9 and/or line 15 Total Quantity to compute the product rate. Compute this rate to six decimals (zeros may be dropped). Enter the amount on line 9h and/or line 15h.

NOTE

To determine an allowance rate for transporting sulfur or gas plant products, first complete Schedule 1C.

STEP 15. Enter on line 16 the total unit allowance rate, which is equal to the sum of:

- Line 9h plus line 15h if the product is gas,
- Line 10g plus line 15h if the product is sulfur, or
- Line 10h plus line 15h if the product is NGLs.

STEP 16. Enter the allowance rate from line 16 to column 12b or 13b on Page 1, whichever is applicable.

STEP 17. Check the appropriate box to indicate whether the information is proprietary or nonproprietary.

6.8.3 Schedule 1A—Non-Arm's-Length Transportation System/Segment Operations, Maintenance, and Overhead Expenditures, Form MMS-4295 (non-arm's-length or no-contract)

Schedule 1A—Non-Arm's-Length Transportation System/Segment Operations, Maintenance, and Overhead Expenditures, Form MMS-4295 (fig. 6-4, p. 6-53), is used to record and summarize reasonable and actual operating, maintenance, and overhead costs for a non-arm's-length or no-contract transportation segment. A separate Schedule 1A must be completed for each segment in the transportation facility. For instance, if a gas transportation system has three segments, three Schedules 1A must be completed. The costs developed on Schedule(s) 1A are accumulated on Schedule 1 to compute the total operating costs for the facility.

Complete payor identification information on Schedule 1A as follows:

STEP 1. Enter the same payor name and code as used on Form MMS-2014.

STEP 2. Enter the same AID number and selling arrangement code as used on Form MMS-2014.

STEP 3. Enter the unique transportation facility name or ID number designated by the payor. Enter the unique transportation segment name or ID number designated by the payor. If a transportation facility consists of only one segment, the segment name or ID number is the same as the facility name or ID number.

STEP 4. Enter the reporting period. The period must be the same period shown in field 6 on Page 1 of Form MMS-4295.

STEP 5. If estimated costs are used for startup, place a check in the Estimated Costs checkbox.

Follow steps 6 through 16 to compute operation, maintenance, and overhead costs:

STEP 6. In parts A, Lessee's Operating Costs for System/Segment, and B, Lessee's Maintenance Costs, identify and list all operating and maintenance costs directly attributable to the transportation facility/segment during the reporting period. If additional space is needed, attach a Supplemental Schedule 1A to identify or explain other cost items.

STEP 7. Sum lines 1 through 9 and enter total operating costs on line 10.

STEP 8. Sum lines 11 through 15 and enter total maintenance costs on line 16.

STEP 9. In part C, Lessee's Overhead Allocation, identify and list all overhead costs directly allocable and attributable to the operations and maintenance of the transportation facility/segment. If additional space is needed, attach a Supplemental Schedule 1A.

STEP 10. Sum lines 17 through 19 and enter the total overhead expenditures directly allocable to the facility/segment on line 20.

STEP 11. Sum lines 10, 16, and 20 and enter total operating and maintenance costs on line 21.

STEP 12. Enter the lease volume transported through this segment and the total throughput of this segment on line 22.

NOTE

Use the total throughput quantity, excluding waste products that have no value. If there are multiple lessees on a lease, each lessee should enter only its portion of the lease volume and total pipeline throughput.

STEP 13. Divide the lease volume by the total throughput and enter the amount on line 22.

STEP 14. Multiply line 21 by line 22 to compute the allocated operation, maintenance, and overhead costs for the segment. Enter this amount on line 23.

STEP 15. Enter the amount from line 23 in column d of Schedule 1, part A or B (fig. 6-2, p. 6-38) as applicable.

STEP 16. Check the appropriate box to indicate whether the information is proprietary or nonproprietary.

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SCHEDULE 1A -- NON-ARM'S-LENGTH TRANSPORTATION SYSTEM/ SEGMENT OPERATIONS, MAINTENANCE AND OVERHEAD EXPENDITURES

PAYOR IDENTIFICATION BLOCK	
Payor Name and Code:	
Accounting ID No:	
Selling Arrangement Code:	
Facility ID No:	
Segment ID No:	
Period: 19 to 19	

☐ Estimated Costs - Check when estimating costs for system/segment start-up.

A. Lessee's Operating Costs for System/Segment

Operations Supervision and Engineering	$	1
Operations Labor		2
Utilities		3
Materials		4
Ad Valorem Property Taxes		5
Rent		6
Supplies		7
Other (specify). Attach Supplemental Schedule 1A		8
as necessary		9
Total Operating Costs -- Subtotal	$	10

B. Lessee's Maintenance Costs

Maintenance Supervision	$	11
Maintenance Labor		12
Materials		13
Other (specify). Attach Supplemental Schedule 1A		14
as necessary		15
Total Maintenance Costs -- Subtotal	$	16

C. Lessee's Overhead Allocation (specify)

______________________	$	17
______________________		18
Other (specify) use Supplemental Schedule 1A		19
Total Overhead Allocation	$	20

D. Total Operating and Maintenance Costs (Line 10 + line 16 + line 20) $ ______ 21

E. Allocated to Segment
Lease Volume ________ ÷ Total throughput ________ $ ______ 22

F. Segment Allocated Operating, Maintenance, and Overhead Costs (Line 21 x line 22) Enter in column d, Schedule 1 $ ______ 23

THIS INFORMATION SHOULD BE CONSIDERED (Please check one) ☐ PROPRIETARY ☐ NONPROPRIETARY

FORM MMS-4295 SCHEDULE 1A (REV. 1/88)

FIGURE 6-4. Schedule 1A—Non-Arm's-Length Transportation System/Segment Operations, Maintenance, and Overhead Expenditures, Form MMS-4295

6.8.4 Supplemental Schedule 1A—Non-Arm's-Length Transportation System/Segment Operations, Maintenance, and Overhead Expenditures, Form MMS-4295 (non-arm's-length or no-contract)

Supplemental Schedule 1A—Non-Arm's-Length Transportation System/Segment Operations, Maintenance, and Overhead Expenditures, Form MMS-4295 (fig. 6-5), is used to identify and document operating, maintenance, and overhead expenditures listed on Schedule 1A under the Other expenditure categories on lines 8 and 9, 14 and 15, and 19. The Supplemental Schedule 1A is a continuation sheet for data that cannot be shown on Schedule 1A because of space limitations.

A separate Supplemental Schedule 1A must be prepared for each type of expense claimed. For instance, if a lessee has only other operating costs to claim, only one Supplemental Schedule 1A is required. If a lessee has other operating, other maintenance, and other overhead costs, three Supplemental Schedules 1A must be submitted.

Complete Supplemental Schedule 1A as follows:

STEP 1. Complete payor ID information (payor name and code, accounting ID number, selling arrangement code, facility ID number, segment ID number, and period) following Schedule 1A instructions.

STEP 2. Describe each expenditure item and list the amount. Payors should retain receipts and invoices for future MMS review and/or audit.

STEP 3. Sum the expenditures and enter the total amount on the Total line.

STEP 4. Enter the total amount of the operations, maintenance, and/or overhead expenditures on Schedule 1A, lines 8 and 9, 14 and 15, and/or 19, respectively. Individual totals for operations, for maintenance, and for overhead expenditures must be computed on separate Supplemental Schedules 1A.

STEP 5. Check the appropriate box to indicate whether the information is proprietary or nonproprietary.

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SUPPLEMENTAL SCHEDULE 1A-- NON-ARM'S-LENGTH TRANSPORTATION SYSTEM/ SEGMENT OPERATIONS, MAINTENANCE, AND OVERHEAD EXPENDITURES

PAYOR IDENTIFICATION BLOCK
Payor Name and Code: ______
Accounting ID No: ______
Selling Arrangement Code: ______
Facility ID No: ______
Segment ID No: ______
Period: 19 to 19

Type of Expenditure - Describe

______	$ ______
______	______
______	______
______	______
______	______
______	______
______	______
______	______
______	______
______	______
______	______
______	______
______	______
______	______
______	______
______	______
______	______
______	______
______	______
______	______

FOR ILLUSTRATION ONLY

Total $ ______

THIS INFORMATION SHOULD BE CONSIDERED (Please check one) ☐ PROPRIETARY ☐ NONPROPRIETARY

FORM MMS-4295 SUPPLEMENTAL SCHEDULE 1A (REV. 1/88)

FIGURE 6-5. Supplemental Schedule 1A—Non-Arm's-Length Transportation System/Segment Operations, Maintenance, and Overhead Expenditures, Form MMS-4295

6.8.5 Schedule 1B—Non-Arm's-Length Transportation System/Segment Depreciation and Capital Expenditure Summary, Form MMS-4295 (non-arm's-length or no-contract)

Schedule 1B—Non-Arm's-Length Transportation System/Segment Depreciation and Capital Expenditure Summary, Form MMS-4295 (fig. 6-6), summarizes the actual or estimated facility/segment depreciation and undepreciated capital investment costs for a non-arm's-length or no-contract situation.

A separate Schedule 1B must be completed for each segment. The costs of all segments are then accumulated on Schedule 1 to determine the total depreciation and undepreciated capital investment for the facility. Complete Schedule 1B as follows:

STEP 1. Complete payor ID information (payor name and code, accounting ID number, selling arrangement code, facility ID number, segment ID number, and period) following Schedule 1A instructions.

Enter each facility/segment capital expenditure item on a separate line, as follows:

STEP 2. In column 1, Expenditure Item, identify the capital expenditure item.

STEP 3. In column 2, Initial Capital Investment and Date Placed in Service, enter the initial capital expenditure amount and the month and year the item was placed in service.

STEP 4. In column 3, Salvage Value, enter a reasonable salvage value.

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SCHEDULE 1B -- NON-ARM'S-LENGTH TRANSPORTATION SYSTEM/SEGMENT DEPRECIATION AND CAPITAL EXPENDITURE SUMMARY

PAYOR IDENTIFICATION BLOCK
Payor Name and Code:
Accounting ID No:
Selling Arrangement Code:
Facility ID No:
Segment ID No:
Period: 19 to 19

1 Expenditure Item	2 Initial Capital Investment and Date Placed in Service	3 Salvage Value	4 Depreciable Life/Years of Depreciation Taken to Date	5 Undepreciated Capital Investment at Beginning of Year	6 Depreciation	7 Undepreciated Capital Investment at End-of-Year
	$	$		$	$	$

	5	6	
Totals	$	$	8
Allocated to Segment (from line 22, Schedule 1A)	$	$	9
Segment Depreciation and Capital Expenditure (Line 8 x line 9) Enter in column g and e, Schedule 1	$	$	10

THIS INFORMATION SHOULD BE CONSIDERED (Please check one) ☐ PROPRIETARY ☐ NONPROPRIETARY

FORM MMS-4295 SCHEDULE 1B (REV 1/88)

FIGURE 6-6. Schedule 1B—Non-Arm's-Length Transportation System/Segment Depreciation and Capital Expenditure Summary, Form MMS-4295

STEP 5. In column 4, Depreciable Life/Years of Depreciation Taken to Date, enter the depreciable life of the expenditure and the number of years of depreciation taken to date.

STEP 6. In column 5, Undepreciated Capital Investment at Beginning of Year, enter the undepreciated capital investment at the beginning of the year (or beginning of the reporting period) shown in the payor ID information field. Salvage value must be deducted from the initial capital investment.

STEP 7. In column 6, Depreciation, enter the amount of depreciation to be taken for the year (or reporting period). In computing depreciation, the payor may elect to use either a straight-line depreciation method or a unit-of-production method. When an election is made, the payor may not alternate methods without MMS approval. Equipment cannot be depreciated below a reasonable salvage value.

NOTE

If a lessee is reporting for only 6 months of the year or the pipeline has been in service for only 6 months, the lessee must adjust the depreciation expense for the portion of the year in which the expense applies. For example, if the depreciable base of the pipeline is \$2,000,000 and the estimated life is 20 years, the depreciation expense per year would be \$100,000. The depreciation expense for 6 months would be calculated as follows:

$$\text{Depreciation} = \$100{,}000 \times \frac{6}{12} = \$50{,}000$$

STEP 8. In column 7, enter the undepreciated capital investment at the end of the year. This is computed by subtracting depreciation (column 6) from the beginning of the year (or beginning of the reporting period) undepreciated capital investment (column 5). This amount is used as the next year’s beginning of the year undepreciated capital investment.

STEP 9. Total columns 5 and 6, and enter the amounts on line 8.

STEP 10. Enter the amounts from line 8 on Schedule 1, parts A and/or B, columns g and e, respectively.

STEP 11. On line 9, columns 5 and 6, enter the Allocated to Segment amount from line 22 of Schedule 1A.

STEP 12. For columns 5 and 6, multiply line 8 by line 9, and enter the amounts on line 10.

STEP 13. Enter the amounts from line 10 on Schedule 1, parts A and/or B, columns g and e, respectively.

STEP 14. Check the appropriate box to indicate whether the information is proprietary or nonproprietary.

6.8.6 Schedule 1C—Allowance for Non-Arm's-Length Transportation of Gas Liquids and Sulfur from the Lease to the Gas Processing Plant, Form MMS-4295 (non-arm's-length or no-contract)

Schedule 1C—Allowance for Non-Arm's-Length Transportation of Gas Liquids and Sulfur from the Lease to the Gas Processing Plant, Form MMS-4295 (fig. 6-3, p. 6-42) is used to determine an allowance for transporting NGLs or sulfur from a **lease** to a processing facility in non-arm's-length or no-contract situations.

Schedule 1C must be submitted with Page 1 and Schedule 1 of Form MMS-4295. No allowance may be claimed if the facility is on the lease site. Refer to "Schedule 1C—Allowance for Non-Arm's-Length Transportation of Gas Liquids and Sulfur from the Lease to the Gas Processing Plant, Form MMS-4295 (arm's-length)" on page 6-41 for instructions for completing Schedule 1C.

6.9 Reporting for Arm's-Length POP Contracts

On September 13, 1991, MMS published a final rule in the *Federal Register* (56 FR 46527) affecting the determination of gas value for royalty purposes in situations where the lessee's arm's-length contract for the sale of gas prior to processing provides for the value to be determined based upon a percentage of the purchaser's proceeds resulting from processing the gas. This rule, effective November 1, 1991, changed valuation of gas sold under arm's-length POP contracts from the processed gas valuation regulations at 30 CFR 206.153 and 30 CFR 206.173 to the unprocessed gas valuation regulations at 30 CFR 206.152 and 30 CFR 206.172. MMS also adopted a new provision in the unprocessed gas valuation regulations requiring that the value for royalty purposes for gas sold under arm's-length POP contracts be no less than a value equivalent to 100 percent of the residue gas value, less any applicable allowances for post-plant transportation.

From March 1, 1988, to October 31, 1991, gas sold under **all** POP contracts (arm's-length and non-arm's-length) was valued as processed gas under 30 CFR 206.153. Operators were required to report the disposition of such gas to PAAS on the Monthly Report of Operations (Form MMS-3160) as gas transferred to a plant. Lessees were required to report royalties for this gas to AFS using product code 03 for processed gas and product codes 07, 19, and 05 as appropriate for liquids, sulfur, and drip/scrubber condensate, respectively. Associated allowances were required to be reported on the Report of Sales and Royalty Remittance, Form MMS-2014, using TC 11 for transportation allowances and TC 15 for processing allowances. Lastly, lessees were required to file Gas Transportation Allowance Reports, Form MMS-4295, and Gas Processing Allowance Summary Reports, Form MMS-4109, with the Royalty Valuation Division prior to claiming any allowances on the Form MMS-2014. The publication of the final POP rule as discussed below discontinued these requirements for gas sales under **Federal arm's-length** POP contracts. Reporting requirements for gas sales under non-arm's-length POP contracts remain unchanged. For more information on POP contracts, see Chapter 4, "Gas Valuation," and Chapter 7, "Gas Processing Allowances."

The following guidance is provided to assist lessees in determining gas transportation allowances under the POP rulemaking. The determination of gas processing allowances is discussed in chapter 7.

Because the rule affecting arm's-length POP contracts is effective **prospectively** only, Federal lessees are required to have the appropriate Forms MMS-4295 filed as specified at 30 CFR 206.156 through 30 CFR 206.157 for the period prior to November 1, 1991. Effective November 1, 1991, Federal lessees will not be required to file Form MMS-4295 for gas sold under arm's-length POP contracts. **All Indian lessees must continue to file gas transportation and processing forms for accounting-for-comparison (dual accounting) purposes**.

If lessees currently have an allowance form on file showing an estimated allowance for calendar year 1991, an allowance form showing the actual report (report type 2) should have been filed with MMS for the period January 1, 1991, through October 31, 1991, by January 31, 1992 (30 CFR 206.157(c)(1)(iii)).

Direct questions on valuation under this new rule to the Royalty Valuation Division. For questions regarding the PIFs contact the Accounting and Reports Division. And for questions regarding the Monthly Report of Operations (Form MMS-3160) contact the Accounting and Reports Division. For contact information, see "Important Addresses and Phone Numbers" on page 1-5.

NOTE

The requirements for accounting-for-comparison and major portion analysis contained in Indian lease terms are not affected by the POP rulemaking. Thus, even though lessees sell gas produced from an Indian lease under an arm's-length POP contract, if lease terms require accounting for comparison and the value of the processed gas is greater than the value determined under 30 CFR 206.172, the lessee cannot report royalties on one line utilizing product code 04 on Form MMS-2014. Instead, lessees would be required to report royalties utilizing product codes 03, 07, and 19 (and 05, if appropriate) on Form MMS-2014 and file the applicable allowance forms before claiming any allowance.

6.10 Reporting on Form MMS-2014

Transportation allowances must be reported as a separate line entry on Form MMS-2014 under column 11 using TC 11 unless MMS approves a different reporting procedure (30 CFR 206.177(c)(4)). When reporting a transportation allowance, the lessee reports the royalty due (TC 01) on one line based on the full quantity of unprocessed gas, or on two lines based on the full quantity of residue gas and gas plant products (fig. 6-7). On the next line, the lessee reports the transportation allowance (TC 11) as a **positive** royalty quantity and a negative royalty value in columns 17 and 18, respectively. Royalties are due on the value of the unprocessed gas minus the transportation allowance, or the value of the residue gas plus all gas plant products minus the transportation allowance. Refer to the *Oil and Gas Payor Handbook, Volume II* for detailed information for reporting on Form MMS-2014.

6.11 Due Dates for Allowance Reports

For reporting transportation costs incurred under **arm's-length** contracts, Page 1 and Schedule 1 of Form MMS-4295 must be submitted. For **non-arm's-length** contracts or no-contract situations, Page 1 and all appropriate schedules must be submitted. The appropriate forms must be filed with MMS prior to the time or at the same time the transportation deduction is reported on Form MMS-2014. A Form MMS-4295 received by MMS by the end of the month when Form MMS-2014 is due will be considered timely filed (30 CFR 206.177(c)(1)(i) and 30 CFR 206.177(c)(2)(i)). If the due date falls on a weekend or a Federal holiday, the form will be considered timely filed if it is received by MMS by 4 p.m. mountain time on the next Government business day.

The initial Form MMS-4295 is effective for a reporting period beginning the month the lessee is first authorized to deduct an allowance. The effective period continues until the end of the calendar year, until the contract or rate terminates, or until the contract or rate is modified or amended, whichever is earlier (30 CFR 206.177(c)(1)(ii) and 30 CFR 206.177(c)(2)(ii)).

For succeeding reporting periods, the lessee must submit the appropriate forms within 3 months after the end of the calendar year or after the applicable contract or rate is amended, modified, or terminated, whichever is earlier. However, MMS may approve a longer period during which the lessee will continue to use the allowance rate from the previous reporting period (30 CFR 206.177(c)(1)(iii) and 30 CFR 206.177(c)(2)(iii)).

NOTE

If a gas estimated payment is on file with AFS (TC 03), the lessee has an additional 30 days in which to submit its **initial** Form MMS-4295. The lessee, however, **does not** have an extra 30 days in which to submit its routine Form MMS-4295. A routine Form MMS-4295 is due within 3 months after the end of the previous reporting period.

Transportation allowances that were in effect as of March 1, 1988, were allowed to continue until such allowances terminated or until December 31, 1988, whichever was earlier.

Page ____ of ____

OMB 1010-0022 (Expires August 31, 20XX)

U.S. DEPARTMENT OF THE INTERIOR
Minerals Management Service – Royalty Management Program

Report of Sales and Royalty Remittance
Form MMS-2014

For MMS Use Only

REPORT MO./YR.: 0 2 9 0

1 PAYOR'S NAME Bob Henry Oil Company

2 PAYOR CODE 1 2 3 4 5

3 FEDERAL [ ] OR INDIAN [X]

3a PAYOR-ASSIGNED DOCUMENT NUMBER _ _ _ _ _ _

4	5 RESERVED FOR PREPARER'S USE	6 ACCOUNTING IDENTIFICATION (AID) NUMBER	7 PROD CODE	8 REG PRICE CODE	9 SELL ARR CODE	10 SALES MONTH/ YEAR	11 TRANS CODE	12 ADJ REAS CODE	13 SALES QUANTITY	14 QUALITY MEASURE-MENT	15 CALC METH	16 SALES VALUE	17 ROYALTY QUANTITY	18 ROYALTY VALUE	19 PMT METH CODE
1		5160012340001	04		001	01/90	01		1,000 00			3,000 00	125 00	375 00	
2		5160012340001	04		001	01/90	11						-125 00	-94 00	
3															
4															
5															

FIGURE 6-7. Reporting Example, Report of Sales and Royalty Remittance, Form MMS-2014

6.12 Extension to File Form MMS-4295—Indian Leases Only

To request an extension to file Form MMS-4295, the lessee of an Indian lease must submit an extension request with supporting documentation in writing on or before the original due date of the form. It is MMS policy is to grant a maximum 90-day extension to file Form MMS-4295. The extension request must contain the following information:

- Payor number
- Form number (Form MMS-4295)
- MMS lease number
- Report type (extension to file estimate, actual, or both)
- Reporting period for which the extension applies

If the lessee is requesting an extension to file an initial report, the allowance may not be claimed on Form MMS-2014 until the allowance form is filed (regardless of whether or not an extension is granted). If an allowance is claimed on Form MMS-2014 before the initial Form MMS-4295 is filed, interest is assessed.

If the lessee is requesting an extension to file a continuing report, the lessee may continue to use the allowance rate from the previous reporting period until Form MMS-4295 is filed for the current reporting period.

NOTE

Regardless of whether a gas estimated payment is on file with AFS (TC 03), a request for an extension to file Form MMS-4295 is due on or before the original due date of Form MMS-4295.

6.13 Application for Exceptions

MMS may approve an exception to the reporting requirements under the following three conditions:

1. When transportation costs exceed the 50-percent limitation;

2. When the lessee applies for an exception from computing actual costs and completing all addendum schedules under non-arm's-length or no-contract situations; and

3. When a lessee of an Indian lease requests approval to claim a transportation allowance more than 3 months prior to the date that the initial Form MMS-4295 was filed.

The lessee must submit a request for the exception annually. If MMS approves the request, the lessee should follow the arm's-length reporting requirements.

6.13.1 Exception to 50-percent limitation

The transportation allowance deduction on the basis of a selling arrangement cannot exceed 50 percent of the value of the oil (30 CFR 206.156(c)(2) and 30 CFR 206.176(c)(2)). However, on request of a lessee, MMS may approve a transportation allowance in excess of the 50-percent limitation if the lessee meets the following conditions:

1. The lessee submits a written application for an exception and provides all relevant documentation for MMS to make a determination. The submitted information should include, but not be limited to:

   - A complete list of AID numbers, product codes, selling arrangement numbers, and payor code(s);

   - A full description of the transportation system, contracts, invoices, or tariffs;

   - Points of sale and delivery;

   - Production volumes;

   - Costs and explanation of costs; and

   - Applicable time periods.

2. A request for an exception to the 50-percent limitation is submitted annually if actual costs exceed 50 percent of the value of the oil each year.

3. The lessee demonstrates that the transportation costs incurred in excess of the limitation were reasonable, actual, and necessary.

4. The value for royalty purposes under any selling arrangement is not reduced to zero.

6.13.2 Exception to compute actual costs

If a lessee has a non-arm's-length transportation contract or has no contract, including those situations where the lessee performs transportation for itself, the transportation allowance is based on the lessee's reasonable, actual costs (30 CFR 206.157(b)(1) and 30 CFR 206.177(b)(1)). However, on request of a lessee, MMS may grant an exception from the requirement to compute actual costs only if the lessee has a FERC- or State-approved tariff (30 CFR 206.157(b)(5) and 30 CFR 206.177(b)(5)).

MMS will deny the lessee's request if the tariff is excessive compared to arm's-length transportation charges in the area. If there are no arm's-length charges, MMS will deny the lessee's request if:

- No FERC or State cost analysis exists, and if MMS objects to a lessee's filing, the appropriate agency declines to investigate the filing; and

- The tariff significantly exceeds the lessee's actual costs.

6.13.3 Exception to 3-month retroactive limitation

A gas transportation allowance may be claimed retroactively for a period not more than 3 months prior to the first day of the month in which the allowance report is filed with MMS. However, MMS may approve allowances to be claimed retroactively for a period longer than 3 months upon a showing of good cause by the lessee (30 CFR 206.177(a)(1)(i) and 30 CFR 206.177(b)(1)). To receive approval to exceed the 3-month retroactive allowance filing requirement, the lessee must request approval in writing and provide evidence of good cause for failing to meet the deadline for filing allowances.

MMS administratively defines "good cause" in terms of two basic elements:

1. **Justifiable delay**: Events causing "justifiable delay" must have been (1) outside the individual's control, (2) within immediate proximity to the due date, and (3) a contributing factor in the lessee's failure to timely file the appropriate allowance forms. Contributing factors include natural disasters or death or illness of the lessee or a member of the lessee's immediate family.

2. **Reasonable diligence**: Evidence that the lessee was diligent up to the point in time when the event causing justifiable delay occurred **and** acted promptly after the cause of the delay was identified and/or resolved.

Denial of an allowance is a serious matter because it may substantially increase the value of production for royalty purposes. However, MMS provides a period of 3 months in which to submit allowance forms, which is considered a reasonable length of time. A lessee that is acting in a diligent manner should be able to submit the forms within the 3-month period. If this is impossible, the lessee should submit an estimated allowance or request an extension to file before the due date for the allowance forms. Failure to file because the lessee forgot or was too busy is **not** considered sufficient justification to approve a retroactive period.

6.14 Interest Assessments for Incorrect or Late Reports and Failure to Report—Indian Leases Only

The lessee of an Indian lease must file a Form MMS-4295 **before** claiming a processing allowance on the Form MMS-2014. If the lessee files an erroneous Form MMS-4295, files the Form MMS-4295 **after** claiming an allowance on the Form MMS-2014, or fails to file the Form MMS-4295, the lessee will be charged interest on the amount of the deduction until the filing requirements are met. In addition, if the lessee does not file the correct reports within the 3-month allowance filing period, the lessee must pay back the allowance amount that was claimed on the Form MMS-2014.

Interest on royalty underpayments is determined in accordance with 30 CFR 218.54 as follows:

- An interest charge shall be assessed on unpaid and underpaid amounts from the date the amounts are due.
- The interest charge on late payments shall be at the underpayment rate established by the *Internal Revenue Code*, 26 U.S.C. 6621 (a)(2)(Supp. 1987).
- Interest will be charged only on the amount of the payment not received. Interest will be charged only for the number of days the payment is late.

If a lessee deducts a transportation allowance on its Form MMS-2014 before Form MMS-4295 is filed with MMS, a noncompliance letter is issued every month until the requirements of the regulations are met. MMS began issuing noncompliance letters with the August 1989 report month. No noncompliance letters were issued prior to that month. However, lessees are responsible for all report months before August 1989, even though no letter was sent.

Any transportation allowance line (TC 11) claimed on Form MMS-2014 for a sales month for a specific payor number, AID number, product code, and selling arrangement must have a corresponding allowance Form MMS-4295 on file covering the same sales month for the same specific payor number, AID number, product code, and selling arrangement combination.

To avoid an interest assessment for late filing, lessees may request an extension to file the allowance Form MMS-4295 up to a maximum of 90 days. However, if an extension is requested for the initial filing, the lessee may not deduct a transportation allowance on its Form MMS-2014 until the Form MMS-4295 is actually filed. The procedures for filing an extension are discussed in "Extension to File Form MMS-4295—Indian Leases Only" on page 6-64.

6.15 Adjustments

If the lessee's actual transportation allowance differs from the allowance reported, the lessee must file a corrected Form MMS-2014. Data are reported on Form MMS-2014 on a sales month basis; therefore, if an adjustment is needed, there must be a separate adjustment for each sales month.

If the actual transportation allowance is less than the amount the lessee has estimated and claimed during the reporting period, the lessee is required to pay additional royalties due plus interest (30 CFR 218.54). Interest is computed retroactively to the first month the lessee is authorized to deduct a transportation allowance. The lessee must submit a corrected Form MMS-2014 to reflect actual costs, together with any payment due, in accordance with instructions provided by MMS.

If the actual transportation allowance is greater than the amount the lessee has estimated and claimed during the reporting period, the lessee is entitled to a credit without interest. The lessee must submit a corrected Form MMS-2014 to reflect actual costs and follow the recoupment or refund procedure specified by MMS. For offshore leases, any recoupment or refund request must also follow the procedures outlined in the "Dear Payor" letters dated December 20, 1991, and January 15, 1993. (These letters explain the December 15, 1981, Solicitor's Opinion entitled, "Refunds and Credits Under the Outer Continental Shelf Lands Act," M-36942, 88 I.D. 1090, 1101-1102 (1981).) The lessee should contact the appropriate Royalty Error Correction representative for specific instructions. See "Important Addresses and Phone Numbers" on page 1-5.

6.16 Computer-Generated Form MMS-4295—Indian Leases Only

Prior written approval from MMS is required if a lessee of an Indian lease wants to submit its allowance information on automated allowance forms instead of using official MMS forms. The lessee must submit a copy of its proposed computer-generated form to MMS. The placement of all fields on the computer-generated form must be identical to the fields on the official MMS form.

7. Gas Processing Allowances

This chapter describes the procedures for calculating and reporting allowances for processing gas produced from Federal and Indian leases. Processing allowances are granted to the lessee for the costs it incurs in the extraction and recovery of gas plant products from a gas stream. These allowances may be deducted from the value of the individual gas plant products to determine royalties paid to MMS. For the purposes of this chapter, a gas plant product is a separate marketable element, compound, or mixture, whether in liquid, gaseous, or solid form, that results from processing gas. Gas plant products are exclusive of residue gas (30 CFR 206.151 and 30 CFR 206.171).

Processing is defined as any process designed to remove elements or compounds (hydrocarbon and nonhydrocarbon) from gas, including absorption, adsorption, or refrigeration. Field processes that normally take place on or near the lease, such as natural pressure reduction, mechanical separation, heating, cooling, dehydration, and compression, are not considered processing. The changing of pressures and/or temperatures in a reservoir is not considered processing.

A processing allowance may be taken for each eligible gas plant product. However, only those costs attributable to processing each individual gas plant product may be included in the processing allowance computation. A separate processing allowance must be calculated for each general gas plant product recovered at a processing facility for every arm's-length or non-arm's-length contract the lessee has with each plant owner.

The regulations covering processing allowances for Federal leases are at 30 CFR 206.158 and 30 CFR 206.159. The regulations covering processing allowances for Indian leases are at 30 CFR 206.178 and 30 CFR 206.179.

7.1 Products Eligible for Processing Allowances

The products eligible for processing allowances are those products that are royalty bearing (except residue gas) as discussed in the following sections.

The lessee may not take an allowance for costs of processing lease production that is not royalty bearing (30 CFR 206.159(b)(3) and 30 CFR 206.179(b)(3)). A substance that is not royalty bearing is a substance, excluding waste products that have no value, that is not subject to royalty. In calculating a processing allowance for a gas stream that contains both royalty-bearing and non-royalty-bearing production, only the costs associated with processing the royalty-bearing products are deductible.

7.1.1 Gas plant products

Processing allowances may be deducted from the value of gas plant products based on the individual costs of recovering each gas plant product. Gas plant products that qualify for a processing allowance include NGLs, sulfur, CO_2, and nitrogen. Ethane, propane, butane, and natural gasoline are all NGLs and are considered collectively as one product.

7.1.2 Residue gas exclusion

Residue gas (methane) does not qualify for a processing allowance, unless the raw gas stream is “atypical” and the lessee incurs extraordinary costs to process the gas (30 CFR 206.158(d)(2) and 30 CFR 206.178(d)(2)).

“Atypical” gas is defined as gas that does not contain liquefiable hydrocarbons, such as ethane, propane, butane, etc. To obtain an extraordinary processing allowance, the lessee not only must demonstrate that the raw gas stream is atypical, but also that the processing costs are, by reference to standard industry conditions and practice, extraordinary, unusual, or unconventional. The lessee must apply to MMS for an extraordinary cost allowance. When NGLs or other gas plant products are extracted from a gas stream and residue gas remains, royalty is due on 100 percent of the value of residue gas recovered from processing. All costs of extraction are applied to the gas plant products.

If no residue gas is recovered at the plant, MMS may designate an appropriate gas plant product whose value may not be reduced for a processing allowance. The gas plant product disqualified for a processing allowance is the product with the highest total value of all products recovered at the plant.

7.1.3 Drip and scrubber condensate exclusion

Drip or scrubber condensate is condensate recovered on the lease or anywhere on the gas stream before processing (30 CFR 206.151 and 30 CFR 206.171). Condensate recovered in this manner is not eligible for a processing allowance. However, condensate extracted by the manufacturing process is considered a gas plant product and is eligible for a processing allowance.

7.2 Limitations and Exceptions

Processing allowances are limited to 66 2/3 percent of the value of the respective gas plant product determined at the plant. The value of the gas plant product at the plant is the value determined under “Processed Gas” on page 4-34 of this handbook, less the allowance for transportation from the plant to a sales point remote from the plant (30 CFR 206.158(c)(2) and 30 CFR 206.178(c)(2)).

Limitations. Under arm’s-length situations, the processor may retain a portion of the gas plant products as a fee for processing. In these situations, the value retained as a processing fee, which the lessee reports as a processing allowance, cannot exceed 66 2/3 percent of the value of the products at the plant.

In arm’s-length situations where the processor retains both a portion of residue gas and gas plant products as a processing fee, the value of that portion of residue gas retained is added to the value of the retained portion of gas plant products. The sum of the values of retained portions of residue gas and gas plant products cannot exceed 66 2/3 percent of the value of gas plant products at the plant.

Exceptions. If the lessee incurs processing costs that exceed the limit of 66 2/3 percent of the value of the gas plant products, the lessee may request MMS approval for a processing allowance deduction in excess of the limitation. MMS requires the lessee to submit an application for exception to the limitation annually (see "Exception to 66 2/3 percent limitation," p. 7-54 for more information).

MMS makes a determination based on the merits of the case. However, for royalty purposes, under no circumstances shall the value of the gas plant products be reduced to zero. The lessee may not claim a processing allowance that is greater than 99 percent of the value of the gas plant products.

The lessee may not report allowances in excess of the 66 2/3 percent limit on Form MMS-2014 until MMS approves the lessee's application for an exception.

7.2.1 Plant products not in marketable condition

When calculating a processing allowance, distinction must be made between operations that are actually required to extract gas plant products and operations required to place lease products in marketable condition in order to meet contract specifications. To satisfy contract terms, the producer is obligated to condition the gas to meet certain pressure, purity, and water saturation specifications. Costs associated with dehydration, separation, and compression do not qualify for a processing allowance.

The removal of CO_2 and H_2S from sour gas, commonly referred to as sweetening, is considered a cost of placing the gas in marketable condition. These costs are not allowable deductions. However, if sour gas is processed for removal of H_2S that is further converted to elemental sulfur, a processing allowance is permitted if the sulfur is sold or otherwise has value. Similarly, if extracted CO_2 has value, processing costs are an allowable deduction. As with transportation allowances, no processing allowance is permitted for production that is not royalty bearing, such as unsalable CO_2 or sulfur.

7.2.2 NPSLs

NPSLs were issued under Section 8(a) of OCSLA. OCSLA required that alternative bidding systems be established for leases on the OCS. The *Federal Register* Notice entitled "Fixed Net Profit Share Bidding System for Outer Continental Shelf Oil and Gas Leases and Accounting Procedures for Determining Net Profit Share Payments: Final Rule" (45 FR 36784—May 30, 1980) established the accounting method to be used to report costs and revenues for NPSLs.

Rather than paying a fixed royalty, the NPSL operator pays a fixed percentage of the net profits based on the revenue received from the production and sale of oil and gas minus the cost of production. Under this system, the lessee recovers expenses of exploration and development plus a reasonable return on that investment from production revenues prior to any net profit share payment to the Federal Government.

The MMS Director's approval of a Development and Coordination Document combined with the language at 30 CFR 220.011(g) and 30 CFR 220.011(o) permits the lessee to include, in the NPSL capital account, allowable costs associated with transportation and processing. Thus, transportation and processing allowances for NPSLs should not be claimed as separate deductions on Form MMS-2014.

7.3 Allowable and Nonallowable Processing Costs

A processing allowance may be claimed for the reasonable, actual costs incurred for and directly related to the actual processing of lease production.

7.3.1 Arm's-length processing costs

MMS allows a deduction for the reasonable, actual processing costs incurred by the lessee under an arm's-length contract. If a question arises as to the legitimacy of an arm's-length contract, the lessee has the burden of demonstrating that its contract is arm's-length in accordance with MMS standards. The criteria defining an arm's-length contract are provided in Chapter 4, "Gas Valuation."

Allowable costs. Costs directly related to the actual processing of gas are allowable costs.

For example, if an arm's-length contract lists a processing fee of $0.25/gal, but the lessee is billed a discounted fee of $0.21/gal, only the $0.21/gal actually paid may be deducted as a processing allowance.

Nonallowable costs. Costs not directly related to the actual processing of gas are nonallowable costs.

A lessee may not claim a processing allowance greater than the consideration actually transferred, either directly or indirectly, from the lessee to the processor regardless of the costs or fees identified in the arm's-length contract. If the contract lists more costs than the lessee actually pays, only that portion the lessee pays is eligible for a processing allowance.

For example, if an arm's-length contract states that the processing fee is $0.10/gal, but the lessee pays only $0.05/gal as an out-of-pocket expense, the lessee would claim $0.05/gal as a processing allowance.

7.3.2 Non-arm's-length costs

If the lessee has a non-arm's-length contract or no contract, including those situations where the lessee processes its own gas, the processing allowance is divided into two categories:

- Costs associated with capital investment, and
- Costs associated with operations, maintenance, and overhead, collectively referred to as operating and maintenance costs.

MMS may request copies of invoices to verify capital costs and operating and maintenance costs claimed by the lessee.

7.3.2.1 Capital costs

Allowable costs. Depreciable fixed assets, including delivery and installation costs, that are an integral part of the processing/extraction facility are allowable capital costs. Most capital items are located in the plant, beginning at the inlet of the plant and ending at the tailgate of the plant. Transportation facilities owned by the lessee and used to move raw make from an extraction plant to a fractionation plant are an allowable capital plant expenditure.

Capital costs vary considerably between plants because no two plants are exactly alike even though they possess superficial similarities. Examples of common investment items found in different types of plants and considered allowable capital costs are:

- Plant and office buildings, warehouses, shops, and laboratories.
- Sidewalks, fences, plant roads, and rights-of-way for plant roads.
- Freshwater wells and supply systems.
- Heat, steam, power, fuel, sewage, and other general plant facilities; all related controls; and meters, including plant inlet and residue gas sales meters.
- Compression facilities for refrigeration or recompression of gas required during processing and pipe valves, fittings, and equipment items, such as absorbers, heat exchangers, coolers, chillers, fractionating columns, and liquid sweetening facilities, whose primary function is the recovery of plant products, including NGLs.

Nonallowable costs. The following capital costs are nonallowable deductions:

- Nondepreciable property, such as land and pipeline rights-of-way.
- Facilities used to store, deliver, or otherwise dispose of residue gas or products after extraction.
- Costs incidental to marketing; for example, on-lease and other nonallowable compressors, dehydrators, and separators.

- Schools, hospitals, roads, sewer plants, and other capital improvements or equipment not an integral part of the processing facility.
- Costs associated with the preparation of an environmental impact statement. (However, costs for environmental equipment that is an integral part of the gas processing facility are allowable.)

7.3.2.2 Operating and maintenance costs

Allowable costs. Nondepreciable costs that are directly attributable to the operation and maintenance of a gas processing facility are allowable operating and maintenance costs. These costs include:

- Salaries and wages paid to employees and supervisors while engaged in the operation and maintenance of plant equipment and facilities.
- Fuel and utility costs directly related to processing gas.
- Chemicals, including rust preventives and thinning agents, and lubricants used for protection or cleaning of plant facilities.
- Repairs, labor, materials, and supplies directly related to the processing equipment and facilities.
- Insurance, ad valorem property taxes, and payroll taxes (Federal and State income taxes are not allowable deductions).
- Arm's-length rental, leasing, or contract services for equipment, facilities, and onsite installation or maintenance of equipment and facilities.
- General administrative overhead costs (salaries, telephone service, employee benefits, vehicle expenses, office supplies, etc.) directly attributable and allocable to the operation and maintenance of the plant. The lessee should maintain records to support all overhead costs included in a gas processing allowance.

Operating and maintenance expenses are limited to those items that, in the judgment of MMS, are an integral part of gas processing.

Nonallowable costs. Operating and maintenance costs not directly related to processing are nonallowable. These include, but are not limited to:

- Federal and State income taxes, production taxes, royalty payments, or fees, such as State or Indian severance taxes.
- Any costs associated with nonallowable capital improvements or equipment.
- Any costs incidental to marketing that the lessee is obligated to perform at no cost to the lessor; for example, gathering, dehydration, compression, or storage costs incurred on a lease or unit.
- Costs associated with the operation of schools, hospitals, roads, and sewers.

7.4 Allocation of Processing Costs

If a contract includes more than one gas plant product and the processing costs attributable to each product cannot be determined from the arm's-length contract, non-arm's-length contract, or no-contract situation, the total processing costs must be allocated among all products in a consistent and equitable manner. The lessee must propose a cost allocation method to MMS and submit all data relevant to its proposal. The lessee may use its proposed allocation method until MMS issues its determination. The initial proposal must be submitted within 3 months of the last day of the month for which the lessee first deducts a processing allowance. MMS will approve the method unless MMS determines that the method is not consistent with the purposes of the regulations.

For arm's-length contracts, the costs defined in the contracts will be used for allocating costs among all products. For non-arm's-length or no-contract situations, allocations are based on the lessee's reasonable, actual costs, including operating and maintenance expenses, depreciation, and return on undepreciated capital investment costs. Allocation of gas plant costs should accurately reflect the costs of processing each gas plant product.

7.5 Units of Measurement

For the purpose of reporting costs, the lessee must calculate the processing allowance on a dollar-per-unit basis. If the processing costs are defined as a percentage of plant production, the lessee must convert the value of retained production into a dollar amount (30 CFR 206.159(a)(4) and 30 CFR 206.179(a)(4)). If the lessee pays a specific cost per unit of plant production and/or other processing fees, the sum of all costs for each individual product must be used to calculate the processing allowance and to compare with the 66 2/3 percent limitation.

7.6 Reporting and Recordkeeping Requirements

This section describes the reporting and recordkeeping requirements that MMS has established for gas processing allowances. Processing allowances must be reported as a separate line item on Form MMS-2014 using TC 15, unless MMS approves a different reporting procedure.

After a PIF is submitted to MMS designating an individual as a royalty payor (not a rental payor), MMS preprints a Model Form MMS-2014. The Model Form MMS-2014 is sent monthly to the designated individual.

The preprinted Model Form MMS-2014 contains allowance lines if an allowance form has been filed with MMS. If the allowance lines are not preprinted on the lessee's Model Form MMS-2014:

- An appropriate allowance form has not been filed,
- Erroneous data were entered on the allowance form submitted to MMS, or
- The Model Form MMS-2014 was printed before MMS received the allowance form.

In the months in which the allowance lines do not preprint on Model Form MMS-2014, the lessee needs to include these lines manually on its Model Form MMS-2014 before submitting it to MMS. If the allowance form is incorrect, the lessee should contact the Compliance Verification Division. See “Important Addresses and Phone Numbers” on page 1-5.

No prior approval is required to deduct a processing allowance, provided the allowance does not exceed 66 2/3 percent of the individual value of each gas plant product. However, the lessee is required to file the appropriate forms before deducting any estimated or actual allowance on Form MMS-2014. A processing allowance may be claimed retroactively for a period of not more than 3 months prior to the first day of the month that Form MMS-4109 is filed with MMS unless MMS approves a longer period upon a showing of good cause by the lessee. The elements that constitute good cause are determined on a case-by-case basis (see “Extension to File Form MMS-4109—Indian Leases Only,” p. 7-53).

The following forms are used to report gas processing allowances for Indian leases:

Form	Title
Form MMS-4109:	
Page 1	Gas Processing Allowance Summary Report
Schedule 1	Gas Product Allowance Computation Sheet
Schedule 2	Non-Arm’s-Length Processing Facilities Operating Expenses, Depreciation, and Return on Undepreciated Capital Investment
Schedule 2A	Non-Arm’s-Length Processing Facilities Operations, Maintenance, and Overhead Expenditures
Supplemental Schedule 2A	Non-Arm’s-Length Processing Facilities Operations, Maintenance, and Overhead Expenditures
Schedule 2B	Non-Arm’s-Length Processing Facilities Depreciation and Capital Expenditure Summary

Form MMS-4109, with supporting schedules, serves two purposes:

- It notifies MMS that a processing allowance is being claimed on Form MMS-2014 for certain Indian lease(s) production, and

- It provides MMS with the details regarding the computation and the accuracy of the allowance.

A separate processing allowance must be determined for each gas plant product and must be reported as a separate line item on Form MMS-2014 (TC 15) unless MMS approves a different procedure. Unlike transportation, there is no "processing factor." Any deduction from gross value for processing expenses must be reported as a separate line item. Lessees may report the value net of processing costs only for POP contracts.

The valuation regulations governing sales under POP contracts, revised effective November 1, 1991, provide for valuation of gas sold under arm's-length POP contracts using the rules applicable to unprocessed rather than processed gas. For wet gas sold under arm's-length POP contracts, the revised regulations base royalty value on the gross proceeds remitted to the lessee under that contract. Therefore, only the gross proceeds are reported on Form MMS-2014, and processing allowances are not reported as a separate line item (see "POP contracts," p. 4-56).

MMS may establish different reporting requirements than those described herein when circumstances warrant (30 CFR 206.179(c)(1)(vi) and 30 CFR 206.179(c)(2)(vii)).

7.6.1 Arm's-length processing contracts

For processing costs incurred by the lessee under an arm's-length contract, the processing allowance is the reasonable, actual cost incurred by the lessee for processing the gas under that contract.

The lessee is obligated to market gas for the mutual benefit of the lessee and the lessor. MMS expects a lessee to be prudent in negotiating a processing contract that reflects only reasonable, actual processing expenses. If MMS determines that the consideration paid under an arm's-length processing contract does not reflect reasonable value because of misconduct or breach of duty by the lessee to market the production to the mutual benefit of the lessee and the lessor, or if the contract reflects more than the total consideration paid, MMS requires the lessee to determine the processing costs based on the non-arm's-length or no-contract criteria (30 CFR §§ 206.159(a)(1)(iii), 206.179(a)(1)(iii), 206.159(a)(1)(ii), and 206.179(a)(1)(ii)).

The lessee has the burden of demonstrating that its contract is arm's-length. If necessary, MMS may require a lessee to submit its arm's-length processing contracts, fractionation agreements, and related documents to demonstrate that the consideration that is paid reflects reasonable value. These documents must be submitted within a reasonable time as determined by MMS.

If a lessee has arm's-length contracts involving situations where the allowance rate may vary from month to month, the lessee should report its actual costs every month on Form MMS-2014. The lessee should report a volume-weighted-average allowance rate on Form MMS-4109 for the applicable reporting period and indicate "Arm's-Length Contracts" (see "Exception to compute actual costs," p. 7-55).

7.6.2 Non-arm's-length processing contracts or no-contract situations

Processing allowances for non-arm's-length contracts or no-contract situations are based on the lessee's actual costs for processing lease gas during the reporting period. The lessee's actual costs include operating, maintenance, and overhead expenses (combined operating and maintenance costs) and **either**:

- Depreciation and a return on undepreciated capital investment (depreciation method), or
- A return on the initial capital invested in the processing facility (ROI method).

Processing allowances for facilities placed into service before March 1, 1988, may be computed using only the depreciation method. Processing allowances for facilities placed into service on or after March 1, 1988, may be computed using either the depreciation method or the ROI method. After the lessee has elected to use either method to compute the allowance, the lessee may not later change to the other method without MMS approval.

The rate of return used in either the depreciation method or the ROI method is the monthly average industrial BBB bond rate published in *Standard and Poor's Bond Guide* for the first month of the reporting period for which the allowance applies. The rate remains effective during the reporting period and is redetermined at the beginning of each subsequent reporting period.

MMS grants an exception from the requirement that the lessee compute actual costs for non-arm's-length contracts or no-contract situations only if:

- The lessee has arm's-length contracts for processing other gas production at the same plant, and
- At least 50 percent of the gas that is processed annually is processed under arm's-length contracts. See "Exception to compute actual costs" on page 7-55 for more information.

The lessee must submit a request for the exception annually. If MMS approves the request, the lessee should follow the arm's-length reporting requirements.

7.6.2.1 Depreciation

If the lessee uses the depreciation method, depreciation is computed by either:

- Straight-line depreciation based on the reasonable life of the equipment or the reasonable life of the reserves, or
- Unit-of-production method.

After the lessee has elected one method to compute depreciation, the lessee may not later change to the other method without MMS approval. In addition, a change in ownership of the processing facility does not alter the depreciation schedule established by the original lessee; a processing facility or equipment can be depreciated only once. Equipment may not be depreciated below a reasonable salvage value without MMS approval.

If the lessee uses the ROI method, capital costs are computed by multiplying the allowable initial capital invested in the processing plant by the rate of return. Depreciation is not used with this method.

Allowable capital costs are those costs for depreciable fixed assets that are an integral part of the processing plant, including costs of delivery and installation. The allowable and nonallowable capital costs are described in detail in "Capital costs" on page 7-7.

7.6.2.2 Throughput

Processing allowances are based on the total volumes transported through the processing facility during the reporting period.

7.7 Instructions for Completing Form MMS-4109 for Arm's-Length Contracts—Indian Leases Only

Lessees of Indian leases are required to file an allowance report prior to claiming that allowance on Form MMS-2014. The following sections provide instructions for completing Form MMS-4109 for arm's-length contracts.

For arm's-length contracts, the lessee must complete Page 1 and Schedule 1 of Form MMS-4109.

NOTE

Complete the forms in reverse order. For example, prepare Schedule 1 before filling out Page 1.

In the following instructions, wherever a dashed horizontal line appears in an example, a portion of the form has been omitted to save space.

When a lessee is entitled to both a processing allowance and a transportation allowance for a gas product, the transportation allowance must be computed using Form MMS-4295 before completing Form MMS-4109.

7.7.1 Gas Processing Allowance Summary Report (Page 1), Form MMS-4109 (arm's-length)

The Gas Processing Allowance Summary Report (Page 1), Form MMS-4109 (fig. 7-1), is used to report the actual processing allowance claimed for gas plant products during the prior reporting period and to estimate the processing allowance for the current reporting period. Reporting is by AID number (13 digits), product code (2 digits), and selling arrangement (3 digits). Page 1 acts as a summary sheet for information reported on Schedule 1 of Form MMS-4109.

Complete Page 1 of Form MMS-4109 following the instructions below. Any deviation from these instructions may result in the lessee incurring either a payback bill or an interest bill.

NOTE The examples provided do not necessarily relate directly to one another.

U.S. DEPARTMENT OF THE INTERIOR
Minerals Management Service
Royalty Management Program

GAS PROCESSING ALLOWANCE SUMMARY REPORT

OMB NO. 1010 - 0075
Expires August 31, 20XX

FOR MMS USE ONLY:

1 PAYOR NAME ____________

ADDRESS ____________

CITY ____________ STATE ____________ ZIP ____________

2 PAYOR CODE ☐

4 REPORT TYPE ☐

6 PLANT NAME ____________

5 REPORTING PERIOD ______ 19 to ______ 19

3 FOR PAYOR USE ONLY:

FOR ILLUSTRATION ONLY

7	8 ACCOUNTING IDENTIFICATION (AID) NUMBER	9 PRODUCT CODE	10 SELLING ARRANGEMENT CODE	11 ARM'S-LENGTH/ PAYOR-OWNED INDICATOR	12 PRIOR PERIOD ACTUAL DATA a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT	13 CURRENT PERIOD ESTIMATED DATA a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT
1										
2										
3										
4										
5										
6										
7										
8										
9										
10										
11										
12	PAGE TOTAL					xxxxxxxxxxxx			xxxxxxxxxxxx	
13	REPORT TOTAL (LAST PAGE ONLY)					xxxxxxxxxxxx			xxxxxxxxxxxx	

IF MORE LINES ARE NEEDED, ATTACH ADDITIONAL PAGES OF FORM MMS-4109

I have read and examined the statements in this report and, to the best of my knowledge, they are accurate and complete.

NAME (FIRST, MIDDLE INITIAL, LAST) (typed or printed) 14 DATE:

AUTHORIZED SIGNATURE: DATE:

NAME OF PREPARER: TELEPHONE NUMBER:

THIS INFORMATION SHOULD BE CONSIDERED (Please check one) ☐ PROPRIETARY ☐ NONPROPRIETARY

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The Paperwork Reduction Act of 1995 requires us to inform you that this inofrmation is being collected to aid the Minerals Management Service (MMS) in its product valuation and allowance determination process, essential to assuring that Indians receive proper royalty value for minerals removed. Respondents need only submit this information if they choose to file for a royalty allowance; we estimate the burden for voluntary filing is 1/4 hour per allowance data line. Comments on the accuracy of this burden estimate or suggestions on reducing this burden should be directed to the Information Collection Clearance Officer, MS 4230, MMS, 1849 C Street, N.W., Washington, DC 20240 and to the Office of Management and Budget, Office of Information and Regulatory Affiars, Attention: Desk Officer for the U.S. Department of the Interior, Washington, DC 20503. An agency may not conduct or sponsor, and a person is not requred to respond to, a collection of information unless it displays a currently valid OMB control number.

FORM MMS-4109 (REV.8/99)

FIGURE 7-1. Gas Processing Allowance Summary Report, Form MMS-4109

STEP 1. In field 1, Payor Name and Address, enter the payor name and address used to report royalties and processing allowance deductions on Form MMS-2014.

STEP 2. In field 2, Payor Code, enter the same five-digit payor code used on Form MMS-2014.

STEP 3. Field 3, For Payor Use Only, is reserved for payor comment.

STEP 4. In field 4, Report Type, enter the report type indicator. Form MMS-4109 is classified into three report types, described as follows:

Report type 1 is used for initial reporting under the new regulations, reporting on newly acquired lease(s), new plant startup, or reporting estimates only. No prior period actual data are reported in column 12. Only the current period estimated data are completed in column 13.

U.S. DEPARTMENT OF THE INTERIOR
Minerals Management Service
Royalty Management Program

GAS PROCESSING ALLOWANCE SUMMARY REPORT

OMB NO. 1010-0075
Expires August 31, 20XX

FOR MMS USE ONLY:

1 PAYOR NAME JMC Inc.
ADDRESS 20 Happy Lane
CITY Denver STATE CO ZIP 80207
6 PLANT NAME Lucky Gas Processing Plant

2 PAYOR CODE 12345

4 REPORT TYPE 1

5 REPORTING PERIOD 01/01 19 89 to 12/31 19 89

3 FOR PAYOR USE ONLY:

7	8 ACCOUNTING IDENTIFICATION (AID) NUMBER	9 PRODUCT CODE	10 SELLING ARRANGEMENT CODE	11 ARM'S-LENGTH/ PAYOR-OWNED INDICATOR	12 PRIOR PERIOD ACTUAL DATA: a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT	13 CURRENT PERIOD ESTIMATED DATA: a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT
1	5160065430001	07	001	5				5,000	0.400000	2,000
2										
3										

Report type 2 is a continuing report used to report the prior period actual data and current period estimated data. For this report type, column 12 must be completed. If there will be no future production, leave column 13 blank (do not use zeros). If future production is anticipated, complete column 13 with current period estimated data.

STEP 4. ***(continued)***

If the lessee reports current period estimated data in column 13, the automated system generates a reporting period beginning with the first day after the prior period actual data reporting period and continuing until the end of that calendar year.

U.S. DEPARTMENT OF THE INTERIOR
Minerals Management Service
Royalty Management Program

GAS PROCESSING ALLOWANCE SUMMARY REPORT

OMB NO. 1010-0075
Expires August 31, 20XX

FOR MMS USE ONLY:

1 PAYOR NAME JMC Inc.

ADDRESS 20 Happy Lane

CITY Denver STATE CO ZIP 80207

6 PLANT NAME Lucky Gas Processing Plant

2 PAYOR CODE 12345

4 REPORT TYPE 2

5 REPORTING PERIOD 01/01 19 89 to 12/31 19 89

3 FOR PAYOR USE ONLY:

7	8 ACCOUNTING IDENTIFICATION (AID) NUMBER	9 PRODUCT CODE	10 SELLING ARRANGEMENT CODE	11 ARM'S-LENGTH/ PAYOR-OWNED INDICATOR	12 PRIOR PERIOD ACTUAL DATA: a ROYALTY QUANTITY	12 b ALLOWANCE RATE PER UNIT	12 c ROYALTY ALLOWANCE AMOUNT	13 CURRENT PERIOD ESTIMATED DATA: a ROYALTY QUANTITY	13 b ALLOWANCE RATE PER UNIT	13 c ROYALTY ALLOWANCE AMOUNT
1	5160065430001	07	001	5	5,000	0.400000	2,000	5,000	0.400000	2,000
2										
3										

Report type 3 is used to correct previously submitted reports and contains only one reporting period. Either column 12 or 13 must be completed, but not both. If correcting an initial report (report type 1), only one corrected Form MMS-4109 (report type 3) is required. If correcting a continuing report (report type 2), two separate corrected reports (report type 3) are required: one to correct the prior period actual data in column 12 and one to correct the current period estimated data in column 13.

No minus signs are required to reverse the incorrect entry. However, if correcting the payor code, AID number, product code, or selling arrangement, place the correct data in the appropriate field(s) and indicate in field 3 (For Payor Use Only) the original filing date of the report.

STEP 4. *(continued)*

NOTE

A payor code can be corrected only if it is one of the lessee's other valid codes. A lease number cannot be corrected. If a lease number was reported incorrectly, a new report type 1 or 2 must be submitted with the correct lease number. A revenue source, product code, and/or selling arrangement may be corrected.

If correcting the prior period actual data, complete field 12 only. Use the period indicative of the prior period actual data as the reporting period shown in field 5.

U.S. DEPARTMENT OF THE INTERIOR
Minerals Management Service
Royalty Management Program

GAS PROCESSING ALLOWANCE SUMMARY REPORT

OMB NO. 1010-0075
Expires August 31, 20XX

FOR MMS USE ONLY:

1 PAYOR NAME JMC Inc.

2 PAYOR CODE 12345

ADDRESS 20 Happy Lane

CITY Denver STATE CO ZIP 80207

4 REPORT TYPE 3

6 PLANT NAME Lucky Gas Processing Plant

5 REPORTING PERIOD 01/01 19 89 to 12/31 19 89

3 FOR PAYOR USE ONLY: 3/25/90

7	8 ACCOUNTING IDENTIFICATION (AID) NUMBER	9 PRODUCT CODE	10 SELLING ARRANGEMENT CODE	11 ARM'S-LENGTH/ PAYOR-OWNED INDICATOR	12 PRIOR PERIOD ACTUAL DATA a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT	13 CURRENT PERIOD ESTIMATED DATA a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT
1	5160065430001	07	001	5	5,000	0.410000	2,050			
2										
3										

If correcting the current period estimated data, complete column 13 only. Use the period indicative of the current period estimated data as the reporting period shown in field 5.

STEP 4. *(continued)*

U.S. DEPARTMENT OF THE INTERIOR
Minerals Management Service
Royalty Management Program

GAS PROCESSING ALLOWANCE SUMMARY REPORT

OMB NO. 1010-0075
Expires August 31, 20XX

FOR MMS USE ONLY:

1 PAYOR NAME JMC Inc.

2 PAYOR CODE 12345

ADDRESS 20 Happy Lane

CITY Denver STATE CO ZIP 80207

4 REPORT TYPE 3

6 PLANT NAME Lucky Gas Processing Plant

5 REPORTING PERIOD 01/01 19 89 to 12/31 19 89

3 FOR PAYOR USE ONLY: 3/25/90

7	8 ACCOUNTING IDENTIFICATION (AID) NUMBER	9 PRODUCT CODE	10 SELLING ARRANGEMENT CODE	11 ARM'S-LENGTH/ PAYOR-OWNED INDICATOR	12 PRIOR PERIOD ACTUAL DATA a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT	13 CURRENT PERIOD ESTIMATED DATA a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT
1	5160065430001	07	001	5				4,500	0.410000	1,845
2										
3										

The following examples of Form MMS-4109 show an incorrect selling arrangement (report type 2) and the corrected reports (report type 3) required to correct the error. The same procedures are required to correct the revenue source and/or product code except that the correct data are reported in the corresponding Accounting Identification (AID) Number (column 8) and/or Product Code (column 9) column.

In the following examples, the lessee correctly reported selling arrangement code 001 on its Form MMS-2014, but inadvertently reported selling arrangement code 002 on its Form MMS-4109 (report type 2).

STEP 4. *(continued)*

U.S. DEPARTMENT OF THE INTERIOR
Minerals Management Service
Royalty Management Program

GAS PROCESSING ALLOWANCE SUMMARY REPORT

OMB NO. 1010-0075
Expires August 31, 20XX

FOR MMS USE ONLY: Received 3/29/90

1 PAYOR NAME JMC Inc.
ADDRESS 20 Happy Lane
CITY Denver STATE CO ZIP 80207
6 PLANT NAME Lucky Gas Processing Plant

2 PAYOR CODE 12345
4 REPORT TYPE 2
5 REPORTING PERIOD 01/01 19 89 to 12/31 19 89

3 FOR PAYOR USE ONLY:

7	8 ACCOUNTING IDENTIFICATION (AID) NUMBER	9 PRODUCT CODE	10 SELLING ARRANGEMENT CODE	11 ARM'S-LENGTH/ PAYOR-OWNED INDICATOR	12 PRIOR PERIOD ACTUAL DATA a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT	13 CURRENT PERIOD ESTIMATED DATA a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT
1	5160065430001	07	002	5	5,000	0.410000	2,050	5,000	0.410000	2,050
2										
3										

The lessee then submits two separate corrected Forms MMS-4109 (report type 3) to show the correct selling arrangement code of 001 for both the prior period actual data and the current period estimated data.

U.S. DEPARTMENT OF THE INTERIOR
Minerals Management Service
Royalty Management Program

GAS PROCESSING ALLOWANCE SUMMARY REPORT

OMB NO. 1010-0075
Expires August 31, 20XX

FOR MMS USE ONLY:

1 PAYOR NAME JMC Inc.
ADDRESS 20 Happy Lane
CITY Denver STATE CO ZIP 80207
6 PLANT NAME Lucky Gas Processing Plant

2 PAYOR CODE 12345
4 REPORT TYPE 3
5 REPORTING PERIOD 01/01 19 89 to 12/31 19 89

3 FOR PAYOR USE ONLY: 3/25/90

7	8 ACCOUNTING IDENTIFICATION (AID) NUMBER	9 PRODUCT CODE	10 SELLING ARRANGEMENT CODE	11 ARM'S-LENGTH/ PAYOR-OWNED INDICATOR	12 PRIOR PERIOD ACTUAL DATA a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT	13 CURRENT PERIOD ESTIMATED DATA a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT
1	5160065430001	07	001	5	5,000	0.410000	2,050			
2										
3										

STEP 4. ***(continued)***

U.S. DEPARTMENT OF THE INTERIOR
Minerals Management Service
Royalty Management Program

GAS PROCESSING ALLOWANCE SUMMARY REPORT

OMB NO. 1010-0075
Expires August 31, 20XX

FOR MMS USE ONLY:

1 PAYOR NAME JMC Inc.
ADDRESS 20 Happy Lane
CITY Denver STATE CO ZIP 80207
6 PLANT NAME Lucky Gas Processing Plant

2 PAYOR CODE 12345

4 REPORT TYPE 3

5 REPORTING PERIOD 01/01 19 89 to 12/31 19 89

3 FOR PAYOR USE ONLY: 3/25/90

7	8 ACCOUNTING IDENTIFICATION (AID) NUMBER	9 PRODUCT CODE	10 SELLING ARRANGEMENT CODE	11 ARM'S-LENGTH/ PAYOR-OWNED INDICATOR	12 PRIOR PERIOD ACTUAL DATA a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT	13 CURRENT PERIOD ESTIMATED DATA a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT
1	5160065430001	07	001	5				5,000	0.410000	2,050
2										
3										

STEP 5. In field 5, Reporting Period, enter the reporting period for the report type selected as defined below.

NOTE

The reporting period shown for Form MMS-4109 must correspond to the specific **sales** months reported on Form MMS-2014.

Reporting period for a report type 1. A report type 1 indicates that the lessee is reporting only the current period estimated data (column 13). Therefore, the reporting period reflects the current period estimated data.

STEP 5. *(continued)*

U.S. DEPARTMENT OF THE INTERIOR
Minerals Management Service
Royalty Management Program

GAS PROCESSING ALLOWANCE SUMMARY REPORT

OMB NO. 1010-0075
Expires August 31, 20XX

FOR MMS USE ONLY:

1 PAYOR NAME JMC Inc.
2 PAYOR CODE 12345
ADDRESS 20 Happy Lane
CITY Denver STATE CO ZIP 80207
4 REPORT TYPE 1
6 PLANT NAME Lucky Gas Processing Plant
5 REPORTING PERIOD 01/01 19 89 to 12/31 19 89
3 FOR PAYOR USE ONLY: 3/25/90

7	8	9	10	11	12 PRIOR PERIOD ACTUAL DATA			13 CURRENT PERIOD ESTIMATED DATA		
	ACCOUNTING IDENTIFICATION (AID) NUMBER	PRODUCT CODE	SELLING ARRANGEMENT CODE	ARM'S-LENGTH/ PAYOR-OWNED INDICATOR	a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT	a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT
1	5160065430001	07	001	5				5,000	0.400000	2,000
2										
3										

Reporting period for a report type 2. A report type 2 indicates that the lessee is reporting prior period actual data (column 12). The lessee may or may not report current period estimated data (column 13), depending on the anticipation of production. Therefore, the reporting period for a report type 2 always reflects the prior period actual data shown (column 12). If the lessee reports current period estimated data (column 13), the automated system generates a reporting period beginning with the first day following the prior period actual data reporting period and continuing until the end of the same calendar year.

U.S. DEPARTMENT OF THE INTERIOR
Minerals Management Service
Royalty Management Program

GAS PROCESSING ALLOWANCE SUMMARY REPORT

OMB NO. 1010-0075
Expires August 31, 20XX

FOR MMS USE ONLY:

1 PAYOR NAME JMC Inc.
2 PAYOR CODE 12345
ADDRESS 20 Happy Lane
CITY Denver STATE CO ZIP 80207
4 REPORT TYPE 2
6 PLANT NAME Lucky Gas Processing Plant
5 REPORTING PERIOD 01/01 19 89 to 12/31 19 89
3 FOR PAYOR USE ONLY:

7	8	9	10	11	12 PRIOR PERIOD ACTUAL DATA			13 CURRENT PERIOD ESTIMATED DATA		
	ACCOUNTING IDENTIFICATION (AID) NUMBER	PRODUCT CODE	SELLING ARRANGEMENT CODE	ARM'S-LENGTH/ PAYOR-OWNED INDICATOR	a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT	a ROYALTY QUANTITY	b ALLOWANCE RATE PER UNIT	c ROYALTY ALLOWANCE AMOUNT
1	5160065430001	07	001	5	5,000	0.400000	2,000	5,000	0.400000	2,000
2										
3										

STEP 5. ***(continued)***

Reporting period for a report type 3. A report type 3 indicates that the lessee is correcting previously submitted data for a specific reporting period. The lessee should fill out only column 12 to correct prior period actual data.

U.S. DEPARTMENT OF THE INTERIOR
Minerals Management Service
Royalty Management Program

GAS PROCESSING ALLOWANCE SUMMARY REPORT

OMB NO. 1010-0075
Expires August 31, 20XX

FOR MMS USE ONLY:

1 PAYOR NAME JMC Inc.
2 PAYOR CODE 12345
ADDRESS 20 Happy Lane
CITY Denver STATE CO ZIP 80207
4 REPORT TYPE 3
6 PLANT NAME Lucky Gas Processing Plant
5 REPORTING PERIOD 01/01 19 89 to 12/31 19 89
3 FOR PAYOR USE ONLY: 3/25/90

7	8 ACCOUNTING IDENTIFICATION (AID) NUMBER	9 PRODUCT CODE	10 SELLING ARRANGEMENT CODE	11 ARM'S-LENGTH/ PAYOR-OWNED INDICATOR	12 PRIOR PERIOD ACTUAL DATA a ROYALTY QUANTITY	12 b ALLOWANCE RATE PER UNIT	12 c ROYALTY ALLOWANCE AMOUNT	13 CURRENT PERIOD ESTIMATED DATA a ROYALTY QUANTITY	13 b ALLOWANCE RATE PER UNIT	13 c ROYALTY ALLOWANCE AMOUNT
1	5160065430001	07	001	5	5,000	0.410000	2,050			
2										
3										

The lessee should complete only column 13 to correct current period estimated data. Prior Period Actual Data (column 12) must not be filled out.

U.S. DEPARTMENT OF THE INTERIOR
Minerals Management Service
Royalty Management Program

GAS PROCESSING ALLOWANCE SUMMARY REPORT

OMB NO. 1010-0075
Expires August 31, 20XX

FOR MMS USE ONLY:

1 PAYOR NAME JMC Inc.
2 PAYOR CODE 12345
ADDRESS 20 Happy Lane
CITY Denver STATE CO ZIP 80207
4 REPORT TYPE 3
6 PLANT NAME Lucky Gas Processing Plant
5 REPORTING PERIOD 01/01 19 89 to 12/31 19 89
3 FOR PAYOR USE ONLY: 3/25/90

7	8 ACCOUNTING IDENTIFICATION (AID) NUMBER	9 PRODUCT CODE	10 SELLING ARRANGEMENT CODE	11 ARM'S-LENGTH/ PAYOR-OWNED INDICATOR	12 PRIOR PERIOD ACTUAL DATA a ROYALTY QUANTITY	12 b ALLOWANCE RATE PER UNIT	12 c ROYALTY ALLOWANCE AMOUNT	13 CURRENT PERIOD ESTIMATED DATA a ROYALTY QUANTITY	13 b ALLOWANCE RATE PER UNIT	13 c ROYALTY ALLOWANCE AMOUNT
1	5160065430001	07	001	5				5,000	0.410000	2,050
2										
3										

STEP 6. In field 6, Plant Name, enter the plant name. If extraction and fractionation take place at separate facilities, enter the plant name of each facility.

Column 7 represents the line count; that is, the number of allowances being reported.

STEP 7. In column 8, Accounting Identification (AID) Number, enter the same AID number as shown on Form MMS-2014 for each allowance reported.

STEP 8. In column 9, Product Code, enter the same product code as used on Form MMS-2014.

STEP 9. In column 10, Selling Arrangement Code, enter the same selling arrangement code as used on Form MMS-2014.

STEP 10. In column 11, Arm's-Length/Payor-Owned Indicator, enter the arm's-length/payor-owned indicator as follows:

- Enter indicator **5** if processing costs were incurred under a combination of arm's-length and non-arm's-length conditions.
- Enter indictor **6** if 100 percent of the processing costs were incurred under arm's-length conditions.

STEP 11. Column 12, Prior Period Actual Data, is used to report actual cost data for the reporting period.

NOTE

If this is an initial report under the new regulations, a report for newly acquired lease(s), new plant startup, or a report for estimates (no actual data are reported), do not complete column 12. Instead, go to the instructions for column 13.

In column 12a, Royalty Quantity, enter the total royalty quantity processed during the reporting period. Total royalty quantity is the sum of the monthly royalty quantities reported on Form MMS-2014, field 17, for a specific selling arrangement. Decimals are not required in this column.

STEP 11. ***(continued)***

In column 12b, Allowance Rate Per Unit, enter the processing allowance rate from Schedule 1 of Form MMS-4109. The rate in column 12b is computed to six decimals; however, zeros may be dropped.

NOTE

The actual allowance rate cannot exceed 66 2/3 percent of the unit value of the gas product(s) unless MMS has approved a rate in excess of 66 2/3 percent. See "Important Addresses and Phone Numbers" on page 1-5.

In column 12c, Royalty Allowance Amount, enter the royalty allowance amount, computed by multiplying column 12a by 12b. Decimals are not required in column 12c.

STEP 12. Column 13, Current Period Estimated Data, is used to report an initial allowance under the new regulations, a newly acquired lease(s), new plant startup, or estimates (no actual data are reported).

If an allowance was reported for the prior period, the estimated royalty quantity or allowance rate may be the same as the actual quantity or allowance rate reported in column 12. If these are the same, enter the corresponding values from columns 12a, 12b, and 12c into columns 13a, 13b, and 13c, respectively. If the lessee believes the quantity or the rate for the current reporting period will differ from the prior reporting period, the estimates should be adjusted upward or downward.

Estimates should be as accurate as possible and should not exceed 66 2/3 percent of the expected royalty value without prior MMS approval. Overestimating on Form MMS-2014 will result in a royalty underpayment.

Estimates for plant startup are computed as follows:

In column 13a, Royalty Quantity, enter the total estimated royalty quantity to be processed during the current reporting period. Total royalty quantity is the sum of the monthly royalty quantities to be reported for a specific selling arrangement. Decimals are not required in this column.

STEP 12. ***(continued)***

In column 13b, Allowance Rate Per Unit, for **fully arm's-length conditions**, enter the allowance rate specified in the arm's-length contract and shown on Schedule 1. For a **combination of arm's-length and non-arm's-length conditions**, the lessee may use an estimated maximum allowance of 66 2/3 of the value of the product. If the lessee believes that a 66 2/3 percent allowance is excessive, the lessee should use a lower allowance amount. The rate in column 13b is computed to six decimals; however, zeros may be dropped.

In column 13c, Royalty Allowance Amount, enter the estimated royalty allowance amount computed by multiplying column 13a by column 13b. Decimals are not required in column 13c.

STEP 13. Enter page totals on line 12. If more than one Page 1 of Form MMS-4109 is submitted, subtotal the amount on line 12 for each page and enter the total only on line 13 of the last page.

STEP 14. In field 14, enter the name of the person authorized to sign the allowance form. Enter the date. The authorized person must then sign and date the form. Enter the name and telephone number of the person who prepared the form.

STEP 15. In field 15, check the appropriate box to indicate whether the information is proprietary or nonproprietary.

7.7.2 Schedule 1—Gas Product Allowance Computation Sheet, Form MMS-4109 (arm's-length)

Schedule 1—Gas Product Allowance Computation Sheet, Form MMS-4109 (fig. 7-2), is used to calculate the processing allowance rate for each plant product based on actual costs. A separate Schedule 1 must be completed for each unique product code. Complete Schedule 1, Form MMS-4109, following the instructions below:

STEP 1. In field 1, enter the same payor name, payor code, and payor address as shown on Form MMS-2014.

STEP 2. In field 2, enter the plant name and operator. If extraction and fractionation take place at separate facilities, enter the plant name and operator of each facility.

STEP 3. In field 3, enter the product code for which the allowance rate applies.

STEP 4. Enter the current 12-month reporting period in field 4. This must be the same period shown in field 5 on Page 1 of Form MMS-4109 (fig. 7-1, p. 7-17).

Complete the following step-by-step procedures for each AID number under which the plant product is reported:

STEP 5. In column a, Accounting Identification (AID) Number, enter the same AID number used on Form MMS-2014.

STEP 6. In column b, Selling Arrangement Number, enter the same selling arrangement number used on Form MMS-2014.

STEP 7. In column c, Sales Quantity, enter the total sales quantity reported under the AID number/selling arrangement during the reporting period. The total sales quantity is determined by totaling the monthly sales quantities reported on Form MMS-2014 during the reporting period.

U.S. DEPARTMENT OF THE INTERIOR
Minerals Management Service
Royalty Management Program

SCHEDULE 1 -- GAS PRODUCT ALLOWANCE COMPUTATION SHEET

PAYOR NAME AND CODE ____ 1 ____ / ____

PLANT NAME & OPERATOR ____ 2 ____

ADDRESS ____

CITY ____ STATE ____ ZIP ____

PRODUCT CODE: 3

PERIOD: 4 19 to 19

(a) Accounting Identification (AID) Number	(b) Selling Arrangement Number	(c) Sales Quantity	(d) Arm's-Length Processing Costs ($)	(e) Non-Arm's-Length Processing Costs ($)	(f) Processing Costs ($) (d) + (e)	(g) Sales Value ($)	(h) Post-Processing Transportation Costs ($)	(i) Sales Value Less Allowable Trans. Costs (g) - (h)
	TOTALS			TOTALS				

FOR ILLUSTRATION ONLY

Enter as the Product Processing Allowance Rate the lesser of: the unit processing cost [total processing costs (column f) divided by sales quantity (column c)] ____ 5 ____; or two thirds of the unit value less transportation [total sales less transportation (column i) divided by total sales quantity (column c) times .666667] ____ 6 ____. The allowance rate is to be carried to 6 decimal places; i.e., 0.574635. 7

THIS INFORMATION SHOULD BE CONSIDERED (Please check one) ☐ PROPRIETARY ☐ NONPROPRIETARY 8

FORM MMS-4109 SCHEDULE 1 (REV. 1/88)

FIGURE 7-2. Schedule 1—Gas Product Allowance Computation Sheet, Form MMS-4109

STEP 8. If all of the costs for processing the plant products are incurred under arm's-length conditions, enter the total arm's-length processing cost in column d, Arm's-Length Processing Costs. Determine the total arm's-length processing costs by multiplying the contract cost per unit times the quantity reported in column c. If two or more rates apply during the reporting period, the cost incurred under each rate must be computed and totaled. For example, if the rates for NGLs are $0.12/gal for 50,000 gallons and $0.15/gal for 10,000 gallons, the arm's-length processing cost is $0.12 times 50,000 gallons ($0.12 x 50,000 = $6,000) plus $0.15 times 10,000 gallons ($0.15 x 10,000 = $1,500) for a total processing cost of $7,500 ($6,000 + $1,500 = $7,500).

STEP 9. Column e, Non-Arm's-Length Processing Costs, is not used for arm's-length processing costs; leave column e blank.

STEP 10. Enter the processing costs from column d into column f, Processing Costs.

STEP 11. In column g, Sales Value, enter the total sales value reported for the AID number/selling arrangement. Total sales value is determined by totaling the monthly sales values reported on Form MMS-2014 during the reporting period.

STEP 12. In column h, Post-Processing Transportation Costs, enter the post-processing transportation allowance amount for the product by AID number/selling arrangement. This amount is obtained from Schedule 1, part B of Form MMS-4295. Use the total transportation allowance amount, not just the royalty portion. In this example, $100 is used for illustrative purposes only.

STEP 13. In column i, Sales Value Less Allowable Transportation Costs, enter the sales value less allowable post-processing transportation costs for the product. This is calculated by subtracting the transportation allowance amount in column h from the sales value in column g.

STEP 14. Total column c, column f, and column i for the product; and enter these totals under columns c, f, and i on the totals line. If more than one page of Schedule 1 is submitted, enter the individual column totals for all pages on only the last page of Schedule 1.

STEP 15. On the last page of Schedule 1, divide the column f total by the column c total to calculate the unit processing cost. Enter this value in field 5 at the bottom of Schedule 1. Calculate this value to six decimals (zeros may be dropped).

Divide the column i total by the column c total and multiply by 0.666667 to calculate 66 2/3 percent of the unit sales value less transportation. Enter this value in field 6 at the bottom of Schedule 1. Calculate this value to six decimals (zeros may be dropped).

Compare the two values calculated in this step and enter the lesser of the values in field 7 below column i. This value is the calculated allowance rate.

STEP 16. At field 8, check the appropriate box to indicate whether the information is proprietary or nonproprietary.

7.8 Instructions for Completing Form MMS-4109 for Non-Arm's-Length Contracts or No-Contract Situations—Indian Leases Only

Lessees of Indian leases are required to file an allowance report prior to claiming that allowance on Form MMS-2014. The following sections provide instructions for completing Form MMS-4109 for non-arm's-length contracts or no-contract situations.

For non-arm's-length contracts or no-contract situations, the lessee must complete Page 1, Schedule 1, Schedule 2, Schedule 2A, Supplemental Schedule 2A (if necessary), and Schedule 2B.

NOTE

Fill out the forms in reverse order. For example, prepare Schedule 2B before filling out Schedule 2.

7.8.1 Gas Processing Allowance Summary Report (Page 1), Form MMS-4109 (non-arm's-length or no-contract)

The Gas Processing Allowance Summary Report (Page 1) of Form MMS-4109 (fig. 7-1, p. 7-17) is used to report the actual processing allowance amount claimed for gas plant products during the prior reporting period and to estimate the royalty processing allowance amount for the current reporting period. Reporting is done by AID number (13 digits), product code (2 digits), and selling arrangement (3 digits).

Page 1 acts as summary sheet for information on Schedule 1 of Form MMS-4109. Refer to "Gas Processing Allowance Summary Report (Page 1), Form MMS-4109 (arm's-length)" on page 7-16 for full instructions for completing Page 1.

7.8.2 Schedule 1—Gas Product Allowance Computation Sheet, Form MMS-4109 (non-arm's-length or no-contract)

Schedule 1—Gas Product Allowance Computation Sheet, Form MMS-4109 (fig. 7-2, p. 7-30), is used to calculate the processing allowance rate for each plant product based on the actual costs. A separate Schedule 1 must be completed for each unique product code.

Information from Schedules 2, 2A, and 2B of Form MMS-4109 must be used to complete Schedule 1. Instructions for completing Schedule 1 of Form MMS-4109 follow. Refer to "Schedule 1—Gas Product Allowance Computation Sheet, Form MMS-4109 (arm's-length)" on page 7-29 for other examples.

STEP 1. In field 1, enter the same payor name, payor code, and payor address shown on Form MMS-2014.

STEP 2. In field 2, enter the plant name and operator. If extraction and fractionation take place at separate facilities, enter the plant name and operator of each facility.

STEP 3. In field 3, enter the product code for which the allowance rate applies.

STEP 4. In field 4, enter the current 12-month reporting period. The period must be the same period shown in field 5 on Page 1 of Form MMS-4109.

Follow these step-by-step procedures for each AID number under which the plant product is reported:

STEP 5. In column a, Accounting Identification (AID) Number, enter the same AID number used on Form MMS-2014.

STEP 6. In column b, Selling Arrangement Number, enter the same selling arrangement number used on Form MMS-2014.

STEP 7. In column c, Sales Quantity, enter the total sales quantity reported under this AID number/selling arrangement during the reporting period. The total sales quantity is determined by totaling the monthly sales quantities reported on Form MMS-2014 during the reporting period.

STEP 8. If a portion of the costs for processing the plant products is incurred under arm's-length contracts, enter the total arm's-length processing costs in column d, Arm's-Length Processing Costs. Determine total arm's-length processing costs by multiplying the contract cost per unit times the sales quantity under that contract in column c. If two or more rates apply during the reporting period, the cost under each rate must be computed and totaled. For example, if the rates for NGLs are $0.12/gal for 130 gallons and $0.10/gal for 150 gallons, the arm's-length processing cost is $0.12 times 130 gallons ($0.12 x 130 = $15.60) plus $0.10 times 150 gallons ($0.10 x 150 = $15.00) for a total processing cost of $30.60 ($15.60 + $15.00 = $30.60).

STEP 9. If the costs or a portion of the costs for processing the plant products are incurred under non-arm's-length or no-contract situations, enter in column e, Non-Arm's-Length Processing Costs, the total non-arm's-length processing costs determined by multiplying the sales quantity in column c by the processing cost per unit from Schedule 2, line 5.

STEP 10. In column f, Processing Costs, enter the sum of the processing costs (column d plus column e).

STEP 11. In column g, Sales Value, enter the total sales value reported for the AID number/selling arrangement. Total sales value is determined by totaling the monthly sales values reported on Form MMS-2014 during the reporting period.

STEP 12. In column h, Post-Processing Transportation Costs, enter the post-processing transportation allowance amount for the product by AID number/selling arrangement. This amount is obtained from Form MMS-4295, Schedule 1, part B. Use the total transportation allowance amount, not just the royalty portion. In this example, $100 is used for illustration purposes only.

STEP 13. In column i, Sales Value Less Allowable Transportation Costs, enter the sales value less allowable post-processing transportation costs for the product. This number is calculated by subtracting the transportation allowance amount in column h from the sales value in column g.

STEP 14. Total column c, column f, and column i for the product, and enter these totals under columns c, f, and i on the totals line of the last page of Schedule 1. If more than one page of Schedule 1 is submitted, the individual column totals for all pages are entered only on the last page of Schedule 1.

STEP 15. On the last page of Schedule 1, divide the column f total by the column c total to calculate the unit processing cost. Enter this value in field 5 at the bottom of Schedule 1. Calculate this value to six decimals (zeros may be dropped).

Divide the column i total by the column c total and multiply by 0.666667 to calculate 66 2/3 percent of the unit sales value less transportation. Enter this value in field 6 at the bottom of Schedule 1. Calculate this value to six decimals (zeros may be dropped).

Compare the two values calculated previously in this step and enter the lesser of the values in field 7 below column i. This value is the calculated allowance rate.

STEP 16. At field 8, check the appropriate box to indicate whether the information is proprietary or nonproprietary.

7.8.3 Schedule 2—Non-Arm's-Length Processing Facilities Operating Expenses, Depreciation, and Return on Undepreciated Capital Investment, Form MMS-4109 (non-arm's-length or no-contract)

Schedule 2—Non-Arm's-Length Processing Facilities Operating Expenses, Depreciation, and Return on Undepreciated Capital Investment, Form MMS-4109 (fig. 7-3), is used to compute a processing allowance rate for each plant product based on the lessee's portion of the actual plant operating, maintenance, and overhead expenditures; depreciation; and return on undepreciated capital investment during the reporting period. A separate Schedule 2 must be completed to calculate processing costs for each gas plant product processed from the gas stream. Schedules 2A and 2B must be completed before Schedule 2.

Complete Schedule 2, Form MMS-4109, following the instructions below:

STEP 1. Enter the same payor name, payor code, and payor address as shown on Form MMS-2014.

STEP 2. Enter the plant name and operator. If extraction and fractionation occur at separate facilities, enter the plant name and operator of each facility.

STEP 3. Enter the product code for which the allowance rate applies.

STEP 4. Enter the current 12-month reporting period. This must be the same period shown in field 5 on Page 1 of Form MMS-4109.

Complete the following steps to calculate the processing allowance rate:

STEP 5. Use Schedule 2B of form MMS-4109 to calculate depreciation and return on undepreciated capital investment. Schedule 2B must be completed before completing the following steps on Schedule 2.

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SCHEDULE 2 -- NON-ARM'S-LENGTH PROCESSING FACILITIES OPERATING EXPENSES, DEPRECIATION, AND RETURN ON UNDEPRECIATED CAPITAL INVESTMENT

PAYOR NAME AND CODE ______________ / ______

ADDRESS ______________

CITY ______________ STATE ______________ ZIP ______________

PLANT NAME & OPERATOR: ______________

PRODUCT CODE: ______________

PERIOD: 19 to 19

Lessee's Portion of Plant Expenses, Depreciation, and Return on Undepreciated Capital Investment

	(a) Plant Depreciation	(b) Undepreciated Capital Investment at Beginning-of-Year	(c) Rate of Return	(d) Return on Undepreciated Capital Investment	(e) Depreciation Plus Return on Capital Investment	
Extraction Facility	$	$		$	$	1a
Fractionation Facility	$	$		$	$	1b
Extraction Facility Operating, Maintenance, and Overhead Expenses (from Schedule 2A, Line 21)					$	2a
Fractionation Facility Operating, Maintenance, and Overhead Expenses (from Schedule 2A, Line 21)					$	2b
Total Lessee Operating and Maintenance Expenses (sum column e of line 1a, 1b, 2a, and 2b)					$	3
Total Product Quantity (including product quantities processed by lessee for third parties under arm's-length contracts)						4
Product Processing Cost per unit carried to six decimal places (Line 3 divided by line 4).					$	5

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FORM MMS-4109 SCHEDULE 2 (REV. 1/88)

FIGURE 7-3. Schedule 2—Non-Arm's-Length Processing Facilities Operating Expenses, Depreciation, and Return on Undepreciated Capital Investment, Form MMS-4109

NOTE

Lines 1a and 2a on Schedule 2 identify the lessee's portion of non-arm's-length costs for the extraction facility owned by the lessee. Lines 1b and 2b identify the lessee's portion of non-arm's-length costs for the fractionation facility owned by the lessee.

STEP 6. On Schedule 2, enter on line 1a, column a, Plant Depreciation, (or line 1b, column a), the total depreciation costs for the reporting period from Schedule 2B, line 8, column 6. A separate Schedule 2B must be completed when the lessee is an interest owner in both the extraction and fractionation facilities.

STEP 7. Enter on line 1a, column b, Undepreciated Capital Investment at Beginning-of-Year, (or line 1b, column b), the total of the undepreciated plant capital investment at the beginning of the year from Schedule 2B, line 8, column 5 plus the total of the salvage values shown in column 3 of Schedule 2B to determine the amount used to compute return on undepreciated capital investment.

NOTE

The total salvage value is also included when calculating return on investment.

STEP 8. In column c, Rate of Return, enter the monthly average rate as published in *Standard and Poor's Bond Guide* for the first month of the reporting period. The rate of return is the industrial rate associated with Standard and Poor's BBB bond rate.

STEP 9. Multiply column b by column c (lines 1a and/or 1b) to calculate the return on undepreciated capital investment. Enter the amount in column d, Return on Undepreciated Capital Investment, on lines 1a and/or 1b.

A reporting period generally covers a calendar year, unless the processing facility is acquired or sold during a calendar year. In the latter case, only the fraction of the return on undepreciated capital investment that applies to the part of the year when the facility is operated by the lessee is reported on Schedule 2, column d.

For example, assume a lessee sells its interest in the processing plant on May 31, 1989. For the final reporting period, January 1, 1989, through May 31, 1989, only 5/12 of the return on undepreciated capital investment is calculated, as follows:

$$\$12,221 \text{ (column b amount)} \times 0.10 \text{ (rate of return, column c)} = \$1,222.10$$

$$\frac{\$1,222.10}{12} = \$101.841667$$

$$\$101.841667 \times 5 \text{ months} = \$509.21$$

STEP 10. Add column a to column d to calculate the depreciation plus return on capital investment. Enter the total in column e, Depreciation Plus Return on Capital Investment, lines 1a and/or 1b.

STEP 11. On line 2a or 2b, enter the total plant operating, maintenance, and overhead costs from Schedule 2A, line 21. A Schedule 2A must be completed to determine these costs. A separate Schedule 2A must be completed when the lessee is an interest owner in both an extraction and a fractionation plant.

STEP 12. Sum the values in column e, lines 1a, 1b, 2a, and 2b to calculate the total lessee operating and maintenance expenses. Enter the total in column e, line 3.

STEP 13. Enter on line 4 the total product quantity processed by the lessee's portion of the plant (extraction plant in the case of sulfur, CO_2, or raw make; fractionation plant in the case of natural gas liquid products [NGLPs]) during the reporting period, including the quantity of third-party products processed by the lessee.

STEP 14. Divide line 3 by line 4 to calculate the unit product processing cost. Enter the value on line 5. Calculate the processing allowance rate to six decimals (zeros may be dropped).

STEP 15. At field 5, check the appropriate box to indicate whether the information is proprietary or nonproprietary.

7.8.4 Schedule 2A—Non-Arm's-Length Processing Facilities Operations, Maintenance, and Overhead Expenditures, Form MMS-4109 (non-arm's-length or no-contract)

Schedule 2A—Non-Arm's-Length Processing Facilities Operations, Maintenance, and Overhead Expenditures, Form MMS-4109 (fig. 7-4, p. 7-41) is used to record the lessee's portion of the reasonable, actual plant operating, maintenance, and overhead costs for processing the products during the reporting period. A separate Schedule 2A must be completed to report the costs for each gas plant product processed from the gas stream. A separate Schedule 2A must also be completed when the lessee is an interest owner in both an extraction and a fractionation plant.

Complete Schedule 2A, Form MMS-4109 following the instructions below:

STEP 1. Enter the same payor name and payor code as shown on Form MMS-2014.

STEP 2. Enter the plant name and operator.

STEP 3. Enter the product code to which the allowance rate applies.

STEP 4. Enter the same reporting period shown in field 5 on Page 1 of Form MMS-4109 (fig. 7-1, p. 7-17).

Complete the following step-by-step procedures to report the operating, maintenance, and overhead costs:

STEP 5. List the lessee's portion of all operating costs directly attributable to the plant products during the reporting period in part A, Lessee's Operating Costs, lines 1 through 9. If additional space is needed to specify and describe other cost items, complete and attach a Supplemental Schedule 2A of Form MMS-4109.

STEP 6. Add lines 1 through 9 to calculate the total operating expenditures directly allocable and attributable to the plant. Enter the total on line 10.

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SCHEDULE 2A -- NON-ARM'S-LENGTH PROCESSING FACILITIES OPERATIONS, MAINTENANCE, AND OVERHEAD EXPENDITURES

PAYOR IDENTIFICATION BLOCK	
Payor Name and Code:	1
Plant Name & Operator:	2
Product:	3
Period: 19 to 19	4

A. Lessee's Operating Costs

Operations Supervision and Engineering	$	1
Operations Labor		2
Utilities		3
Materials		4
Ad Valorem Property Taxes		5
Rent		6
Supplies		7
Other (specify). Attach Supplemental Schedule 2A		8
as necessary		9
Total Operating Costs -- Subtotal	$	10

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B. Lessee's Maintenance Costs

Maintenance Supervision	$	11
Maintenance Labor		12
Materials		13
Other (specify). Attach Supplemental Schedule 2A		14
as necessary		15
Total Maintenance Costs -- Subtotal	$	16

C. Lessee's Overhead Allocation (specify)

	$	17
		18
Other (specify) use Supplemental Schedule 2A		19
Total Overhead Allocation	$	20

D. Total Operating and Maintenance Costs (Line 10 + line 16 + line 20) $ 21

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FORM MMS-4109 SCHEDULE 2A (REV. 1/88)

FIGURE 7-4. Schedule 2A—Non-Arm's-Length Processing Facilities Operations, Maintenance, and Overhead Expenditures, Form MMS-4109

STEP 7. List the lessee's portion of all maintenance costs directly attributable to the plant products during the reporting period in part B, Lessee's Maintenance Costs, lines 11 through 15. If additional space is needed to specify and describe other cost items, complete and attach a Supplemental Schedule 2A of Form MMS-4109.

STEP 8. Add lines 11 through 15 to calculate the total maintenance expenditures directly allocable and attributable to the plant. Enter the total on line 16.

STEP 9. List the lessee's portion of all overhead costs directly allocable and attributable to the processing of the plant products in part C, Lessee's Overhead Allocation, lines 17 through 19. If additional space is needed to specify and describe other cost items, complete and attach a Supplemental Schedule 2A of Form MMS-4109.

STEP 10. Add lines 17 through 19 to calculate the total overhead expenditures directly allocable and attributable to the plant. Enter the total on line 20.

STEP 11. Add lines 10, 16, and 20 to calculate total plant operating, maintenance, and overhead costs. Enter the total in part D, Total Operating and Maintenance Costs, line 21. Also, enter this total on Schedule 2, line 2a. If the costs are associated with a fractionation facility owned by the lessee, enter the total on Schedule 2, line 2b.

STEP 12. At field 5, check the appropriate box to indicate whether the information is proprietary or nonproprietary.

7.8.5 Supplemental Schedule 2A—Non-Arm's-Length Processing Facilities Operations, Maintenance, and Overhead Expenditures, Form MMS-4109 (non-arm's-length or no-contract)

Supplemental Schedule 2A—Non-Arm's-Length Processing Facilities Operations, Maintenance, and Overhead Expenditures, Form MMS-4109 (fig. 7-5) is used to identify and document the lessee's portion of all operations, maintenance, and overhead expenditures listed under Other Expenditure categories on Schedule 2A.

A separate Supplemental Schedule 2A must be prepared for other operations, other maintenance, and other overhead costs associated with the plant but not listed on Schedule 2A.

STEP 1. Complete the payor identification fields 1–4 (Payor Name and Code, Plant Name and Operator, Product, and Period) following Schedule 2A instructions. See "Schedule 2A—Non-Arm's-Length Processing Facilities Operations, Maintenance, and Overhead Expenditures, Form MMS-4109 (non-arm's-length or no-contract)" on page 7-40.

STEP 2. On Supplemental Schedule 2A, list each expenditure item and amount.

NOTE Receipts and invoices are subject to audit and must be retained.

STEP 3. Sum the values for each expenditure and enter the total at field 5 on the Total line.

STEP 4. Enter the total amount of the operations, maintenance, or overhead expenditures from Supplemental Schedule 2A on Schedule 2A (fig. 7-4, p. 7-41), lines 8 and 9, 14 and 15, or 19.

STEP 5. At field 6 at the bottom of Supplemental Schedule 2A, check the appropriate box to indicate whether the information is proprietary or nonproprietary.

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SUPPLEMENTAL
SCHEDULE 2A-- NON-ARM'S-LENGTH PROCESSING FACILITIES OPERATIONS, MAINTENANCE, AND OVERHEAD EXPENDITURES

PAYOR IDENTIFICATION BLOCK	
Payor Name and Code:	1
Plant Name & Operator:	2
Product:	3
Period: 19 to 19	4

Type of Expenditure - Describe

	$

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Total $ 5

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FORM MMS-4109 SUPPLEMENTAL SCHEDULE 2A (REV. 1/88)

FIGURE 7-5. Supplemental Schedule 2A—Non-Arm's-Length Processing Facilities Operations, Maintenance, and Overhead Expenditures, Form MMS-4109

7.8.6 Schedule 2B—Non-Arm's-Length Processing Facilities Depreciation and Capital Expenditure Summary, Form MMS-4109 (non-arm's-length or no-contract)

Schedule 2B—Non-Arm's-Length Processing Facilities Depreciation and Capital Expenditure Summary, Form MMS-4109 (fig. 7-6) is used to summarize the lessee's portion of the actual plant depreciation and undepreciated capital investment associated with the processing of the plant products. The information on this form is used to compute depreciation and return on investment.

STEP 1. Complete payor identification information fields 1–4 (Payor Name and Code, Plant Name and Operator, Product Code, and Period) following Schedule 2A instructions. See "Schedule 2A—Non-Arm's-Length Processing Facilities Operations, Maintenance, and Overhead Expenditures, Form MMS-4109 (non-arm's-length or no-contract)" on page 7-40.

Complete the following instructions for each capital expenditure item:

STEP 2. In column 1, Expenditure Items, list the capital expenditure items.

STEP 3. In column 2, Initial Capital Investment and Date Placed in Service, enter the lessee's portion of the initial capital expenditure amount and the date the expenditure was incurred.

STEP 4. In column 3, Salvage Value, enter a reasonable salvage value.

STEP 5. In column 4, Depreciable Life/Years of Depreciation Taken to Date, enter the depreciable life of the expenditure item and the number of years of depreciation taken to date. Lessees electing the nondepreciating return on investment procedure provided under 30 CFR 206.159(b)(2)(iv)(B) and 30 CFR 206.179(b)(2)(iv)(B) must enter this information even though no depreciation is claimed.

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PAYOR IDENTIFICATION BLOCK
Payor Name and Code:
Plant Name & Operator:
Product Code:
Period: 19 to 19

SCHEDULE 2B -- NON-ARM'S-LENGTH PROCESSING FACILITIES
DEPRECIATION AND CAPITAL EXPENDITURE SUMMARY

1 Expenditure Item	2 Initial Capital Investment and Date Placed in Service	3 Salvage Value	4 Depreciable Life/Years of Depreciation Taken to Date	5 Undepreciated Capital Investment at Beginning of Year	6 Depreciation	7 Undepreciated Capital Investment at End of Year
	$	$		$	$	$
			8 Totals	$	$	

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FORM MMS-4109 SCHEDULE 2B (REV 1/88)

FIGURE 7-6. Schedule 2B—Non-Arm's-Length Processing Facilities Depreciation and Capital Expenditure Summary, Form MMS-4109

STEP 6. In column 5, Undepreciated Capital Investment at Beginning of Year, enter the lessee's portion of the beginning-of-year undepreciated capital investment. In computing this amount, salvage value must be deducted from the initial capital investment.

For lessees electing to use the nondepreciating return on investment procedure provided under 30 CFR 206.159(b)(2)(iv)(B) and 30 CFR 206.179(b)(2)(iv)(B), the beginning-of-year undepreciated capital investment is equivalent to the initial capital investment (provided the asset continues to be employed for processing the plant production and the asset has had no modifications that were capitalized).

STEP 7. In column 6, Depreciation, enter the amount of depreciation to be taken for the year or for the reporting period (if only part of the year is reported).

In computing depreciation, the lessee may elect to use either a straight-line depreciation method or a unit-of-production method. The straight-line method is based on the life of the equipment or the life of the reserves that the plant services. When an election is made, the lessee may not change methods without MMS approval. Equipment may not be depreciated below a reasonable salvage value.

For lessees electing the nondepreciating return on investment procedure, no depreciation expense is entered.

STEP 8. Subtract column 6 from column 5 to calculate the end-of-year undepreciated capital investment. Enter this amount in column 7. This end-of-year amount is used as the next year's beginning-of-year undepreciated capital investment.

For lessees electing the nondepreciating return on investment procedure, the end-of-year capital investment is normally the same as the beginning-of-year capital investment. However, any changes in capitalization not a result of depreciation, such as replacement or asset retirement, should be reflected as the end-of-year capital investment.

STEP 9. Total column 5 and column 6, and enter these totals under columns 5 and 6 on line 8.

Sum the salvage values in column 3 to calculate a total salvage value.

Add the column 5, line 8 total to the Total Salvage value (column 3). Enter this value on Schedule 2, column b, line 1a (fig. 7-3, p. 7-37).

Enter the column 6, line 8 total on Schedule 2, column a, line 1a.

If the costs are associated with a fractionation facility owned by the lessee, enter the total costs on Schedule 2, columns b and a, respectively, on line 1b.

A reporting period generally covers a calendar year unless a lease or facility is acquired or released during a calendar year. In the latter case, only that fraction of the annual depreciation that applies to the part of the year when the lease or facility is operated by the lessee is reported on Schedule 2B, column 6.

For example, assume a lessee sells its interest in a processing plant on July 31, 1990. For the final reporting period, January 1, 1990, through July 31, 1990, only 7/12 of the annual depreciation amount is calculated, as follows:

Investment costs = $20,000,000
Salvage value at 10% = $2,000,000

Investment salvage value = Depreciable investment (investment - salvage value)

$$\$20{,}000{,}000 - \$2{,}000{,}000 = \$18{,}000{,}000$$

$$\text{Annual depreciation at a 20-year life } \frac{\$18{,}000{,}000}{20 \text{ years}} = \$900{,}000$$

$$\frac{\$900{,}000}{12 \text{ months}} = \$75{,}000$$

$$\$75{,}000 \times 7 \text{ months} = \$525{,}000$$

The amount of $525,000 is reported as depreciation for the final reporting period from January 1, 1990, through July 31, 1990.

STEP 10. At field 5, check the appropriate box to indicate whether the information is proprietary or nonproprietary.

7.9 Reporting for Arm's-Length POP Contracts

On September 13, 1991, MMS published a final rule in the *Federal Register* (56 FR 46527) affecting the determination of gas value for royalty purposes in situations where the lessee's arm's-length contract for the sale of gas prior to processing provides for the value to be determined based upon a percentage of the purchaser's proceeds resulting from processing the gas. This rule, effective November 1, 1991, changed valuation of gas sold under **arm's-length** POP contracts from the processed gas valuation regulations at 30 CFR 206.153 and 30 CFR 206.173 to the unprocessed gas valuation regulations at 30 CFR 206.152 and 30 CFR 206.172. MMS also adopted a new provision in the unprocessed gas valuation regulations requiring that the value for royalty purposes for gas sold under arm's-length POP contracts be no less than a value equivalent to 100 percent of residue gas value less any applicable allowances for post-plant transportation.

From March 1, 1988, to October 31, 1991, gas sold under **all** POP contracts (arm's-length and non-arm's-length) was valued as processed gas under 30 CFR 206.153 and 30 CFR 206.173. Operators were required to report the disposition of such gas to PAAS on the Monthly Report of Operations, Form MMS-3160 as gas transferred to a plant. Lessees were required to report royalties for this gas to AFS using product code 03 for processed gas and product codes 07, 19, and 05 as appropriate for liquids, sulfur, and drip/scrubber condensate, respectively. Associated allowances were required to be reported on the Report of Sales and Royalty Remittance, Form MMS-2014 using TC 11 for transportation allowances and TC 15 for processing allowances.

Lastly, lessees of Indian leases were required to file Gas Transportation Allowance Reports, Form MMS-4295 and Gas Processing Allowance Summary Reports, Form MMS-4109 with the Compliance Verification Division before claiming any allowances on the Form MMS-2014. (See "Important Addresses and Phone Numbers" on page 1-5.) The publication of the final POP rule as discussed below discontinued these requirements for gas sales under **Federal arm's-length** POP contracts. Reporting requirements for gas sales under non-arm's-length POP contracts remain unchanged. For additional information on POP contracts see Chapter 4, "Gas Valuation" and Chapter 6, "Gas Transportation Allowances."

The following guidance is provided to assist lessees in determining gas processing allowances under the POP rulemaking. The determination of gas transportation allowances is discussed in "Reporting for Arm's-Length POP Contracts" on page 6-60.

Because the rule affecting arm's-length POP contracts is effective **prospectively** only, Federal lessees are required to have the appropriate Forms MMS-4109 filed as specified at 30 CFR §§ 206.158 through 206.159 and 206.178 through 206.179 for the period prior to November 1, 1991. Effective November 1, 1991, Federal lessees will not be required to file Forms MMS-4109 for gas sold under arm's-length POP contracts. **All Indian lessees must continue to file gas processing and transportation forms for accounting-for-comparison (dual accounting) purposes**.

If lessees currently have an allowance form on file showing an estimated allowance for calendar year 1991, an allowance form showing the actual data (report type 2) should have been filed with MMS for the period January 1, 1991, through October 31, 1991, by January 31, 1992 (30 CFR 206.159(c)(1)(iii) and 30 CFR 206.179(c)(1)(iii)).

Direct questions on valuation under this new rule to the Royalty Valuation Division. For questions regarding PIFs contact the Accounting and Reports Division. And for questions regarding the Monthly Report of Operations, Form MMS-3160 contact the Accounting and Reports Division. For contact information, see "Important Addresses and Phone Numbers" on page 1-5.

NOTE

The requirements of accounting for comparison and major portion analysis contained in Indian lease terms are not affected by the POP rulemaking. Thus, even though lessees sell gas produced from an Indian lease under an arm's-length POP contract, if lease terms require accounting for comparison and the value of the processed gas is greater than the value determined under 30 CFR 206.172, the lessee cannot report royalties on one line using product code 04 on Form MMS-2014. Instead, lessees would be required to report royalties using product codes 03, 07, and 19 (and 05 if appropriate) on Form MMS-2014 and file the applicable allowance forms before claiming any allowance.

7.10 Reporting on Form MMS-2014

Processing allowances must be reported as a separate line entry on Form MMS-2014 under column 11 using TC 15 unless MMS approves a different reporting procedure (30 CFR 206.179(c)(4)). When reporting a processing allowance, the lessee reports the royalty due (TC 01) on two lines based on the full quantity of residue gas and products (see fig. 7-7). On the third line, the lessee reports the processing allowance (TC 15) as a **positive** royalty quantity and a negative royalty value in columns 17 and 18, respectively. Royalties are due on the net amount resulting from the sum of the value of 100 percent of the residue gas plus gas plant products minus the processing allowance. Refer to the *Oil and Gas Payor Handbook, Volume II* for detailed information for reporting on Form MMS-2014.

OMB 1010-0022 (Expires August 31, 20XX)

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Report of Sales and Royalty Remittance
Form MMS-2014

Page 1 of 1

For MMS Use Only

REPORT MO./YR.: 0 2 8 9

1 PAYOR'S NAME JMC Inc.

2 PAYOR CODE 1 2 3 4 5

3 FEDERAL ☐ OR INDIAN X

3a PAYOR-ASSIGNED DOCUMENT NUMBER _ _ _ _ _ _

4	5 RESERVED FOR PREPARER'S USE	6 ACCOUNTING IDENTIFICATION (AID) NUMBER	7 PROD CODE	8 REG PRICE CODE	9 SELL ARR CODE	10 SALES MONTH/ YEAR	11 TRANS CODE	12 ADJ REAS CODE	13 SALES QUANTITY	14 QUALITY MEASURE-MENT	15 CALC METH	16 SALES VALUE	17 ROYALTY QUANTITY	18 ROYALTY VALUE	19 PMT METH CODE
1		5160065430001	03		001	0189	01		4,500 00			13,500 00	750 00	2,250 00	
2		5160065430001	07		001	0189	01		30,000 00			18,000 00	5,000 00	3,000 00	
3		5160065430001	07		001	0189	15						-5,000 00	-2,000 00	
4															
5															

FIGURE 7-7. Reporting Example, Report of Sales and Royalty Remittance, Form MMS-2014

7.11 Due Dates for Filing Allowance Reports—Indian Leases Only

For reporting processing costs incurred under **arm's-length** contracts, Page 1 and Schedule 1 of Form MMS-4109 must be submitted. For **non-arm's-length** contracts or no-contract situations, Page 1 and all appropriate schedules must be submitted. The appropriate forms must be filed with MMS prior to the time or at the same time the processing deduction is reported on Form MMS-2014. A Form MMS-4109 received by MMS by the end of the month when Form MMS-2014 is due will be considered timely filed (30 CFR 206.179(c)(1)(i) and 30 CFR 206.179(c)(2)(i)). If the due date falls on a weekend or a Federal holiday, the form will be considered timely filed if it is received by MMS by 4 p.m. mountain time on the next Government business day.

The initial Form MMS-4109 is effective for a reporting period beginning the month the lessee is first authorized to deduct an allowance. The effective period continues until the end of the calendar year, until the contract or rate terminates, or until the contract or rate is modified or amended, whichever is earlier (30 CFR 206.179(c)(1)(ii) and 30 CFR 206.179(c)(2)(ii)).

For succeeding reporting periods, the lessee must submit the appropriate forms within 3 months after the end of the calendar year or after the applicable contract or rate is amended, modified, or terminated, whichever is earlier. However, MMS may approve a longer period, during which the lessee will continue to use the allowance rate from the previous reporting period (30 CFR 206.179(c)(1)(iii) and 30 CFR 206.159(c)(2)(iii)).

NOTE

If an estimated gas royalty payment is on file with AFS (TC 03), the lessee has an additional 30 days in which to file its initial Form MMS-4109 only. The lessee, however, **does not** have an extra 30 days in which to submit its continuing Form MMS-4109. A continuing Form MMS-4109 is due within 3 months after the end of the previous reporting period.

Processing allowances that were in effect as of March 1, 1988, were allowed to continue until such allowances terminated or until December 31, 1988, whichever was earlier.

7.12 Extension to File Form MMS-4109—Indian Leases Only

To request an extension to file Form MMS-4109, the lessee must submit an extension request with supporting documentation in writing on or before the original due date of the form. It is MMS policy to grant a maximum 90-day extension to file Form MMS-4109. The extension request must contain the following information:

- Payor number
- Form number (Form MMS-4109)
- MMS lease number
- Report type (extension to file estimate, actual, or both)
- Reporting period for which the extension applies
- Plant Name

If the lessee is requesting an extension to file an initial report, the allowance may not be claimed on Form MMS-2014 until the allowance form is filed regardless of whether or not an extension is granted. If an allowance is claimed on Form MMS-2014 before the initial Form MMS-4109 is filed, interest is assessed.

If the lessee is requesting an extension to file a continuing report, the lessee may continue to use the allowance rate from the previous reporting period until Form MMS-4109 is filed for the current reporting period.

NOTE

Regardless of whether a gas estimated payment is on file with AFS, a request for an extension to file Form MMS-4109 is due on or before the original due date of the Form MMS-4109.

7.13 Application for Exception

MMS may approve an exception to the reporting requirements under the following three conditions:

- When processing costs exceed the 66 2/3 percent limitation;
- When the lessee applies for an exception from computing actual costs and completing all addendum schedules under non-arm's-length or no-contract situations; and
- When a lessee of an Indian lease requests approval to claim a processing allowance more than 3 months prior to the date that the initial Form MMS-4109 was filed (see "Extension to File Form MMS-4109—Indian Leases Only," p. 7-53).

The lessee must submit a request for the exception annually. If MMS approves the request, the lessee should follow the arm's-length reporting requirements.

7.13.1 Exception to 66 2/3 percent limitation

The processing allowance deduction on the basis of an individual product cannot exceed 66 2/3 percent of the value of each gas plant product, reduced first by post-processing transportation allowances

(30 CFR 206.158(c)(2) and 30 CFR 206.178(c)(2)). However, at the request of a lessee, MMS may approve a processing allowance in excess of the 66 2/3 percent limitation if the lessee meets the following conditions:

- The lessee submits a written application for an exception and provides all relevant documentation for MMS to make a determination. The submitted information should include but not be limited to:
  - Name of the gas plant,
  - The processing contract and invoices showing the amount paid,
  - Sales value of the product(s),
  - Production volumes,
  - Costs and explanation of costs, and
  - Applicable time periods.
- A request for an exception to the 66 2/3 percent limitation is submitted annually if actual costs exceed 66 2/3 percent of the value of the products each year.
- The lessee demonstrates that the processing costs incurred in excess of the limitation were reasonable, actual, and necessary.
- The value for royalty purposes of any gas plant product is not reduced to zero.

No allowance will be granted for the cost of placing products in marketable condition; for example, on-lease compression, gathering, separation, dehydration, storage, and treatment.

7.13.2 Exception to compute actual costs

If the lessee has a non-arm's-length processing contract or has no contract, including those situations where the lessee performs processing for itself, the processing allowance is based on the lessee's reasonable, actual costs (30 CFR 206.159(b) and 30 CFR 206.179(b)).

On request of a lessee, MMS may grant an exception from the requirement to compute actual costs (30 CFR 206.159(b)(4) and 30 CFR 206.179(b)(4)) under the following conditions:

- The lessee has arm's-length contracts for processing other gas production at the same processing plant.
- At least 50 percent of the gas processed annually at the plant is processed under arm's-length contracts.
- An exception from the requirement to compute actual costs is submitted annually, if applicable.

If MMS grants the exception, the lessee shall use as its processing allowance the volume-weighted-average prices charged other persons under arm's-length contracts for processing at the same plant (30 CFR 206.159(b)(4)(ii) and 30 CFR 206.179(b)(4)(ii)).

The lessee computes the volume-weighted-average price by multiplying the processing charge by the volume processed under each arm's-length contract to compute a total price charged others. For all contracts, the volume processed and total price under each contract are totaled. The lessee then divides the total price by the total volume processed to calculate the volume-weighted-average allowance rate for the reporting period.

For example, the lessee has the following arm's-length contracts at various processing charges during a 12-month reporting period:

Contract	Processing charge/Mcf	Volume processed (Mcf)	Total price
A	$0.21	1,500,000	$ 315,000
B	0.19	1,600,000	304,000
C	0.20	1,550,000	310,000
D	0.23	650,000	149,500
Totals		5,300,000	$1,078,500

$$\frac{\text{Total price charged others}}{\text{Total volume processed}} = \text{Volume-weighted-average allowance rate/Mcf}$$

$$\frac{\$1{,}078{,}500}{5{,}300{,}000\text{ Mcf}} = \$0.203491/\text{Mcf}$$

The Mcf units of measurement are converted to gallons (or long tons if the product is sulfur), and the allowance rate is applied only to gas plant products; residue gas is excluded.

The lessee enters the volume-weighted-average allowance rate on Page 1 of Form MMS-4109 in either column 12b (Prior Period Actual Data) or column 13b (Current Period Estimated Data), whichever applies. In addition, the lessee must indicate "Arm's-Length Contracts" in the For Payor Use Only field on Page 1 of Form MMS-4109. This notifies MMS that the lessee is using a volume-weighted-average allowance rate on its Form MMS-4109.

7.13.3 Exception to 3-month retroactive limitation

A processing allowance may be claimed retroactively for a period of not more than 3 months prior to the first day of the month in which the allowance report is filed with MMS. However, MMS may approve allowances to be claimed retroactively for a period longer than 3 months upon a showing of good cause by the lessee (30 CFR 206.179(a)(1)(i) and 30 CFR 206.179(b)(1)). To receive approval to exceed the 3-month retroactive allowance filing requirement, the lessee must request approval in writing and provide evidence of good cause for failing to meet the deadline for filing allowances.

MMS administratively defines good cause in terms of two basic elements:

- **Justifiable delay**: Events causing "justifiable delay" must have been (1) outside the individual's control, (2) within immediate proximity to the due date, and (3) a contributing factor in the lessee's failure to timely file the appropriate allowance forms. Contributing factors include natural disasters or death or illness of the lessee or a member of the lessee's immediate family.

- **Reasonable diligence**: Evidence that the lessee was diligent until the time when the event causing justifiable delay occurred

and acted promptly after the cause of the delay was identified and/or resolved.

Denial of an allowance is a serious matter because it may substantially increase the value of production for royalty purposes. However, MMS provides a period of 3 months in which to submit allowance forms, which is considered a reasonable length of time. A lessee that is acting in a diligent manner should be able to submit the forms within the 3-month period. If this is impossible, the lessee should submit an estimated allowance or request an extension to file before the due date for the allowance forms. Failure to file because the lessee forgot or was too busy is **not** considered sufficient justification to approve a retroactive period.

7.14 Interest Assessments for Incorrect or Late Reports and Failure to Report

The lessee of an Indian lease must file a Form MMS-4109 **before** claiming a processing allowance on the Form MMS-2014. If the lessee files an erroneous Form MMS-4109, files the Form MMS-4109 **after** claiming an allowance on the Form MMS-2014, or fails to file the Form MMS-4109, the lessee will be charged interest on the amount of the deduction until the filing requirements are met. In addition, if the lessee does not file the correct reports within the 3-month allowance filing period, the lessee must pay back the allowance amount that was claimed on the Form MMS-2014.

Interest on royalty underpayments is determined in accordance with 30 CFR 218.54, as follows:

a. An interest charge shall be assessed on unpaid and underpaid amounts from the date the amounts are due.

b. The interest charge on late payments shall be at the underpayment rate established by the *Internal Revenue Code*, 26 U.S.C. 6621(a)(2)(Supp. 1987).

c. Interest will be charged only on the amount of the payment not received. Interest will be charged only for the number of days the payment is late.

If a lessee deducts a processing allowance on its Form MMS-2014 before Form MMS-4109 is filed with MMS, a noncompliance letter is issued every month until the requirements of the regulations are met. MMS began issuing noncompliance letters with the August 1989 report month. No noncompliance letters were issued prior to that month. However, lessees are responsible for all report months before August 1989, even though no letter was sent.

Any processing allowance line (TC 15) claimed on Form MMS-2014 for a sales month for a specific payor number, AID number, product code, and selling arrangement must have a corresponding allowance Form MMS-4109 on file covering the same sales month for the same specific payor number, AID number, product code, and selling arrangement combination.

To avoid an interest assessment for late filing, lessees may request an extension to file the allowance Form MMS-4109 up to a maximum of 90 days. However, if an extension is requested for the initial filing, the lessee may not deduct a processing allowance on its Form MMS-2014 until the Form MMS-4109 is actually filed. The procedures for filing for an extension are discussed in "Extension to File Form MMS-4109—Indian Leases Only" on page 7-53.

7.15 Adjustments

If the lessee's actual processing allowance differs from the allowance reported, the lessee must file an amended Form MMS-2014. Data are reported on Form MMS-2014 on a sales month basis; therefore, if an adjustment is needed, there must be a separate adjustment for each sales month.

If the actual processing allowance is less than the amount the lessee has estimated and claimed during the reporting period, the lessee is required to pay additional royalties due, plus interest (30 CFR 218.54). Interest is computed retroactively to the first month the lessee is authorized to deduct a processing allowance. The lessee must submit a corrected Form MMS-2014 to reflect actual costs, together with any payment due, in accordance with instructions provided by MMS.

If the actual processing allowance is greater than the amount the lessee has estimated and claimed during the reporting period, the lessee is entitled to a credit without interest. The lessee must submit a corrected Form MMS-2014 to reflect actual costs and follow the recoupment or refund procedure specified by MMS. The lessee should contact the appropriate Royalty Error Correction representative for instructions. See "Important Addresses and Phone Numbers" on page 1-5.

7.16 Computer-Generated Form MMS-4109—Indian Leases Only

Prior written approval from MMS is required if a lessee of an Indian lease wants to submit its allowance information on automated allowance forms in lieu of using official MMS forms. The lessee must submit a copy of its proposed computer-generated form to MMS. The placement of all fields on the computer-generated form must be identical to the fields on the official MMS form.

A. Reporting Forms

The forms listed below are included in this appendix. These forms may be copied and used for reporting purposes.

- Oil Transportation Allowance Report (Page 1), Form MMS-4110
  - Schedule 1—Oil Transportation Facility Summary Sheet
  - Schedule 1A—Non-Arm's-Length Transportation System/Segment Operations, Maintenance, and Overhead Expenditures
  - Supplemental Schedule 1A—Non-Arm's-Length Transportation System/Segment Operations, Maintenance, and Overhead Expenditures
  - Schedule 1B—Non-Arm's-Length Transportation System/Segment Depreciation and Capital Expenditure Summary
- Gas Transportation Allowance Report (Page 1), Form MMS-4295
  - Schedule 1—Gas Transportation Facility Summary Sheet
  - Schedule 1A—Non-Arm's-Length Transportation System/Segment Operations, Maintenance, and Overhead Expenditures
  - Supplemental Schedule 1A—Non-Arm's-Length Transportation System/Segment Operations, Maintenance, and Overhead Expenditures
  - Schedule 1B—Non-Arm's-Length Transportation System/Segment Depreciation and Capital Expenditure Summary
  - Schedule 1C—Allowance for Non-Arm's-Length Transportation of Gas Liquids and Sulfur from the Lease to the Gas Processing Plant

- Gas Processing Allowance Summary Report (Page 1), Form MMS-4109
  - Schedule 1—Gas Product Allowance Computation Sheet
  - Schedule 2—Non-Arm's-Length Processing Facilities Operating Expenses, Depreciation, and Return on Undepreciated Capital Investment
  - Schedule 2A—Non-Arm's-Length Processing Facilities Operations, Maintenance, and Overhead Expenditures
  - Supplemental Schedule 2A—Non-Arm's-Length Processing Facilities Operations, Maintenance, and Overhead Expenditures
  - Schedule 2B—Non-Arm's-Length Processing Facilities Depreciation and Capital Expenditure Summary

These forms are also available online at www.mrm.mms.gov/ReportingServices/Forms/AFSOil_Gas.htm.

Citations and References Index

This index contains the citations made from the *United States Code of Law* (U.S.C.), the *Federal Register* (FR), and the *Code of Federal Regulations* (CFR) and references to legal decisions, official acts, periodicals, and other handbooks.

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Release History

Release number	Release date	Revised chapters/sections	MRM originator	Preparer
1.0	07/21/93		RFT[a]	AMS/OC[b]
2.0	08/01/00		RFT	AMS/OC
2.1	02/15/01	pp. 3-1, 4-1, A-2, and Release History-1	RFT	AMS/OC

a. Regulations and FOIA Team.

b. American Management Systems Operations Corporation, Inc.

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

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

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

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