

**CASE NO. 09-2276  
IN THE UNITED STATES COURT OF APPEALS  
FOR THE TENTH CIRCUIT**

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UTE MOUNTAIN UTE TRIBE

Plaintiff/Appellee,

vs.

RICK HOMANS, SECRETARY OF THE NEW MEXICO TAXATION AND  
REVENUE DEPARTMENT AND NEW MEXICO TAXATION AND  
REVENUE DEPARTMENT

Defendants/Appellants.

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ON APPEAL FROM THE UNITED STATES DISTRICT COURT FOR THE  
DISTRICT OF NEW MEXICO  
The Honorable Parker James A. Parker, District Court Judge  
District Court No. 07-CV-00772 JAP/WDS

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**RESPONSE BRIEF OF APPELLEE UTE MOUNTAIN UTE TRIBE**

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February 16, 2010

**STATEMENT REGARDING ORAL ARGUMENT**

Plaintiff/Appellee (“Tribe” or “UMUT”) does not request oral argument.

**CORPORATE DISCLOSURE STATEMENT**  
**PURSUANT TO FED. R. APP. P. 26.1**

The following are parties to this litigation, including persons or other entities financially interested in the outcome of the litigation, but not revealed by the caption on appeal, *see* 10th Cir. R. 46.1(C), and attorneys not entering an appearance in this court who have appeared for any party in prior trial or administrative proceedings sought to be reviewed, or in related proceedings that preceded the subject action in this court:

None.

## TABLE OF CONTENTS

### Contents

<b>ARGUMENT .....</b>	<b>13</b>
<b>I. STANDARD OF REVIEW.....</b>	<b>13</b>
<b>II. HISTORICAL BACKGROUND .....</b>	<b>13</b>
<b>III. UNITED STATES SUPREME COURT PRECEDENT ESTABLISHES A FLEXIBLE PREEMPTION ANALYSIS FOR DETERMINING WHETHER STATES MAY TAX NON-INDIANS DEVELOPING RESERVATION- CREATED RESOURCES. ....</b>	<b>15</b>
<b>IV. UNDER THE BRACKER PREEMPTION ANALYSIS, HOMANS IS PRE-EMPTED FROM ASSESSING THE FIVE OIL AND GAS TAXES. ....</b>	<b>20</b>
<b>A. Federal And Tribal Regulation Of Oil And Gas On The Ute Mountain Ute Reservation Is Comprehensive And State Regulation Is Unnecessary. ....</b>	<b>21</b>
<b>1. There Is A Comprehensive Scheme Of Federal And Tribal Regulation On The Ute Mountain Ute Reservation. ....</b>	<b>21</b>
<b>2. Federal and Tribal Regulation Of Oil And Gas Development On The Ute Mountain Ute Reservation Leaves No Room Or Necessity For State Regulation Or Interference. ....</b>	<b>32</b>
<b>B. The New Mexico Taxes Result In Economic Harm To The Tribe And Interfere With Federal Interests. ....</b>	<b>40</b>
<b>C. The District Court Correctly Refused Homans’ Arguments That Off-Reservation Record-Keeping And Regulation Of State Infrastructure Amount To Provision Of Substantial Services That Would Justify Taxation.....</b>	<b>44</b>
<b>1. Homans Provides Only <i>De Minimis</i> Services To Oil And Gas Operators On The New Mexico Lands. ....</b>	<b>45</b>
<b>2. Homans’ Regulation Of Off-Reservation Natural Gas Transportation Infrastructure</b>	

**Does Not Provide A Sufficient Basis For State  
Taxation Of Oil And Gas Production On The  
New Mexico Lands.....48**

**D. The District Court Correctly Balanced The Relevant  
Federal, Tribal, And State Interests Under Bracker.....51**

**V. CONCLUSION .....53**

**CERTIFICATE OF SERVICE .....56**

## **TABLE OF AUTHORITIES**

### **Federal Cases**

<i>Arizona v. San Carlos Apache Tribe of Ariz.</i> 463 U.S. 545 (1983).....	11
<i>Barona Band of Mission Indians v. Yee</i> 528 F.3d 1184 (9th Cir. 2008) .....	47
<i>British-American Oil Prod. Co. v. Bd. of Equalization</i> 299 U.S. 159 (1936).....	23
<i>C. River Water Conservation Dist. v. United States,</i> 424 U.S. 800 (1976).....	11
<i>Cherokee Nation v. Georgia</i> 30 U.S. 1 (1831).....	14
<i>Cortez v. McCauley</i> 478 F.3d 1108 (10th Cir. 2007) .....	13
<i>Cotton Petroleum Corp. v. New Mexico</i> 490 U.S. 163 (1989).....	passim
<i>F.W. Hempel &amp; Co., Inc v. Metal World, Inc.</i> 721 F.2d 610 (7th Cir. 1983) .....	13
<i>Four Sons Bakery Inc. v. Dulman</i> 542 F.2d 829 (10th Cir. 1976) .....	13
<i>Kenai Oil and Gas, Inc. v. Dep't of Interior</i> 671 F.2d 383 (10th Cir. 1982) .....	40
<i>McClanahan v. State Tax Comm'n of Ariz.</i> 411 U.S. 164 (1973).....	14
<i>Moe v. Confederated Salish and Kootenai Tribes</i> 425 U.S. 463 (1976).....	14
<i>New Mexico v. Mescalero Apache Tribe</i> 462 U.S. 324 (1983).....	19, 48

<i>Ramah Navajo School Bd., Inc. v. Bureau of Revenue of N.M.</i> 458 U.S. 832 (1982).....	passim
<i>Sac and Fox Nation of Missouri v. Pierce</i> 213 F.3d 566 (10th Cir. 2000) .....	20
<i>Wagon v. Prairie Band Potawatomi Nation</i> 546 U.S. 95 (2005).....	19
<i>White Mountain Apache Tribe v. Bracker</i> 448 U.S. 136 (1980).....	passim
<b>Federal Statutes</b>	
25 U.S.C. §§ 396a-396g.....	5
25 U.S.C. § 396d.....	5
25 U.S.C. § 397 .....	22
25 U.S.C. § 398 .....	21, 22
25 U.S.C. § 398c .....	22
25 U.S.C. § 2101 .....	5
25 U.S.C. § 2102(a) .....	24
25 U.S.C. § 2103(d) .....	24
25 U.S.C. § 2105 .....	25
25 U.S.C. §§ 3501-3504 .....	25
25 U.S.C. § 3503(b)(1)(C) .....	25
43 U.S.C. § 666.....	11
15 Stat. 619 .....	13
18 Stat. 37.....	13
21 Stat. 199 .....	13
28 Stat. 677 .....	4, 14, 22

45 Stat. 495 .....	22
52 Stat. 347 .....	5

## **State Cases**

<i>New Mexico ex rel. State Engineer v. United States</i> Civil No. 75-184 (San Juan County) .....	11
---	----

## **State Statutes**

N.M. Stat. § 7-2-1 .....	51
N.M. Stat. § 7-3A-1 .....	51
N.M. Stat § 7-9-1 .....	51
N.M. Stat. § 7-33-4 .....	51, 52

## **Federal Regulations**

25 C.F.R. § 211.20 .....	28
25 C.F.R. § 211.47 .....	30
25 C.F.R. Part 224.....	27
25 C.F.R. § 224.10 .....	27
25 C.F.R. Part 225.....	27
25 C.F.R. § 225.1(a).....	24
25 C.F.R. § 225.4 .....	27
30 C.F.R. Part 206.....	50
43 C.F.R. Part 3160.....	28
43 C.F.R. § 3160.0-1.....	33
43 C.F.R. §§ 3161.2 .....	30
43 C.F.R. § 3162.1 .....	30
43 C.F.R. § 3162.2-2.....	35

43 C.F.R. § 3162.3-1 .....	28, 35
43 C.F.R. § 3162.3-1(a) .....	29, 31, 32
43 C.F.R. § 3162.3-1(e) .....	30
43 C.F.R. § 3162.3-2 .....	30
43 C.F.R. § 3162.3-4 .....	34
43 C.F.R. § 3162.5-1 .....	30, 37
43 C.F.R. § 3162.5-3 .....	36, 37
59 Fed. Reg. 14971 (March 30, 1994) .....	27, 28
61 Fed. Reg. 35634 (July 8, 1996) .....	27
66 Fed. Reg. 1893 (January 10, 2001) .....	27
73 Fed. Reg. 12808 (March 10, 2008) .....	28

#### **Administrative Cases**

<i>San Juan Citizens Alliance et al.</i> , 129 I.B.L.A. 1 (1999) .....	31
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**STATEMENT OF RELATED CASES**

The Tribe is not aware of any related cases.

### **JURISDICTIONAL STATEMENT**

The Tribe does not dispute the jurisdictional statement submitted by Defendants-Appellants (“Homans”).

## ISSUES PRESENTED

Homans presents this Court with ten legal issues for review. (Opening Br. 2-4.) After reviewing the text of Homans' Opening Brief, the Tribe can identify only three issues relevant for review<sup>1</sup>:

1. May Homans tax oil and gas production on tribal trust lands on the Ute Mountain Ute Reservation when the State of New Mexico provides no services to the Reservation?

2. Is Homans' regulation of the off-reservation natural gas transportation infrastructure for intrastate and interstate consumption a sufficient basis for taxation of Reservation oil and gas production?

3. How is this case different from Cotton Petroleum Corp. v. New Mexico, 493 U.S. 163 (1989)?

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<sup>1</sup> In identifying these three issues, the Tribe notes that Homans has already agreed to the District Court's 311 findings of fact (Opening Br. 20) and recognizes the applicability of the "particularized inquiry" preemption analysis developed in Cotton Petroleum 493 U.S. 163 and its predecessors White Mountain Apache Tribe v. Bracker, 448 U.S. 136 (1980); and Ramah Navajo Sch. Bd. v. Bureau of Revenue of N.M., 458 U.S. 832 (1982). (Opening Br. 34, n. 5 (stating, "Thus, [Homans] did not (and does not) take the position that the Bracker interest-balancing test is inapplicable.").)

## **STATEMENT OF THE CASE**

The Tribe does not dispute the Statement of the Case submitted by Homans.

## **STATEMENT OF FACTS**

The Ute Mountain Ute Reservation lies within both the States of Colorado and New Mexico in the Four Corners Region. The New Mexico portion of the Reservation (“the New Mexico Lands”) was set aside for the Tribe by an 1895 Act of Congress. 28 Stat. 677. [RP 175, Finding 9.] All of the New Mexico Lands are held by the United States in trust for the Tribe. [RP 176, 185, Findings 15, 103.] Currently, no one resides on the New Mexico Lands; they are used by the Tribe for livestock grazing and oil and gas development. [RP 176, Findings 16-17, 19.] The State of New Mexico provides no services on the Reservation. [RP 177, 199, Findings 28, 245.]

There are slightly more than 2,000 members of UMUT, 38.5 percent of whom lived below the poverty line at the time of the 2000 census. [RP 175, 206, Findings 3, 308.] The *per capita* income of tribal members was \$8,159.00 during the 2000 census, approximately half the average for the residents of Montezuma County, Colorado, and San Juan County, New Mexico. [RP 205-06, Findings 305-06.] In 2000 the unemployment rate among tribal members was 11.3 percent, as compared to a range of 2.7 percent to 5.5 percent in the corresponding counties and states. [RP 206, Finding 307.]

Oil and gas leasing of the New Mexico Lands began in the 1950s. [RP 186, Finding 114.] Leases were originally entered into pursuant to, the Indian Mineral Leasing Act (“IMLA”), 25 U.S.C. §§ 396a-396g. [RP 185-186, Finding 113.] Currently most of the mineral development agreements the Tribe negotiates and enters into are mineral development agreements pursuant to the Indian Mineral Development Act of 1982 (“IMDA”), 25 U.S.C. § 2101 et seq. [RP 186, Finding 115.] These agreements expand the Tribe’s opportunity to be an active participant in mineral development of its lands. [RP 186-87, Findings 119-24.] All leases and agreements require the approval of the Secretary of the Interior, whose authority has been delegated to the Bureau of Indian Affairs (“BIA”). [RP 187, Findings 125, 129-30.] Surface management, including the granting of easements and oversight of cultural resources, is the responsibility of the BIA and the Tribe. [RP 189, Findings 148-49, 155.] Under federal law (25 U.S.C. § 396d and regulations promulgated pursuant thereto) all oil and gas operations (“downhole”) are supervised by the Bureau of Land Management (“BLM”), in cooperation with the BIA and the Tribe. [RP 188-89, Findings 138-45, 150-55.] BLM approves Applications for Permits to Drill (“APD”), oversees the disposal of produced water, protects the mechanical integrity of the wells, and oversees the abandonment and plugging of wells, among other operational activities on the Ute Mountain Ute Reservation. [RP 189-90, Findings 142, 158-65.] After BLM

approves permits, it forwards the applicable form to BIA and the New Mexico Oil Conservation Division (“NMOCD”). [RP 189, Finding 157.] There is no provision in federal or tribal law for state approval of any oil and gas activities on the Ute Mountain Ute Reservation, and the District Court found to be *de minimis* the economic value of New Mexico’s services to oil and gas operators on the New Mexico Lands. [RP 201, Finding 264.] The District Court also concluded that federal regulation of oil and gas operations on the Ute Mountain Ute Reservation is exclusive. [RP 228.]

There are 186 active wells on the New Mexico Lands, out of 23,000 active oil and gas wells in the New Mexico portion of the San Juan Basin, a geologic formation, and over 50,000 active wells in the entire state. [RP 181-82, 200, Findings 71-73, 256.] NMOCD is responsible for the regulation of oil and gas operations in the State of New Mexico.<sup>2</sup> That includes protection of the public from the adverse environmental effects of petroleum production. However, except

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<sup>2</sup> Pages 13-15 of the Statement of Facts in Homans’ Opening Brief describe the mission, policies, and procedures of the NMOCD with few references to the District Court’s findings. The Tribe does not dispute these descriptions, except for any inference that the legal authority of NMOCD extends to the New Mexico Lands or that NMOCD exercises concurrent jurisdiction over UMUT oil and gas operations with BLM—propositions which Homans unsuccessfully sought to prove at trial. The Tribe submits that numerous findings of fact support the District Court’s conclusion that the economic value of NMOCD regulation of oil and gas operators on the New Mexico Lands is *de minimis*. In view of the statement in Homans’ Opening Brief that Appellant does not take issue with any of the District Court’s findings, the Tribe offers only a short summary of the court’s findings pertaining to the role of NMOCD. (Opening Br. 20.)

for two citizen complaints of hydrogen sulfide (“H<sub>2</sub>S”) originating from wells on the New Mexico Lands, no evidence was introduced to show that wells operated on the New Mexico Lands have caused any actual or potential adverse environmental effects, including groundwater contamination or effects on wildlife, on any lands adjoining the Ute Mountain Ute Reservation. [RP 191, Findings 171-82.]

Historically, BLM has generally adopted well-spacing and setback requirements set by state agencies. [RP 194, Finding 203.] In 1995 and 1996 BLM issued two orders, called Ute Mountain Ute #1 and #2, respectively. These orders establish well spacing for wells for certain of the most active formations on the Reservation. The BLM presented its plan at hearings scheduled by NMOCD and the Colorado Oil Conservation Division. [RP 250, 266.] For each formation named, specific drilling and spacing units were established. The purpose of developing this programmatic scheme was to protect the correlative rights of all parties concerned, to prevent drilling of unnecessary wells, and to promote conservation of UMUT oil and gas resources. [RP 192-93, Findings 183-91.]

In addition, Ute Mountain Ute #1 permitted commingling of several of the newly designated formations. [RP 193, Finding 191.] It also allowed BLM officers to authorize exceptions when topographical, surface hazards, and archaeological sites presented themselves. [RP 255.]

The BLM retained the authority for the granting of permits for non-standard spacing and infill wells. [RP 192, Finding 189.] In 1999 BLM and NMOCD entered into a Memorandum of Understanding (“MOU”) pursuant to which NMOCD issued draft orders for Indian lands, including UMUT lands, and the BLM would review such orders and make an independent decision on whether to approve them. [RP 193-94, Findings 192-202.] The MOU expired in 2004 [RP 194, Finding 202], and was not renewed at the election of NMOCD [TR 395-97].

Since 1992 the Tribe has barred NMOCD officials from entering the Reservation without permission. [RP 194, Finding 207.] A 2002 publication from the website of the New Mexico Department of Energy, Minerals, and Natural Resources (of which NMOCD is a part), states: “The State of New Mexico does not have jurisdiction [over energy and minerals development] on Indian reservation ... lands.” [RP 285.] That publication was withdrawn from the website prior to the trial in this case, and NMOCD continues to require operators on the New Mexico Lands to fill out forms and to seek approvals for activities already approved by BLM. [RP 180-81, Findings 62, 64.] Under regulations promulgated on December 1, 2008, NMOCD requires those operators to use BLM forms for permit applications and various reports, but NMOCD still requires its approval after BLM approval. [RP 180, Finding 62.] When an operator does not follow NMOCD regulations or fill out the required forms, NMOCD may revoke

the operator's authority to transport natural gas or oil within the State of New Mexico, making it difficult for the operator to continue operations on the New Mexico Lands. [RP 180-81, Finding 64.]

All oil and gas operators on the New Mexico Lands pay royalties to the Tribe, and the federal Minerals Management Service ("MMS") performs royalty accounting and auditing in conjunction with the Tribe's own program. [RP 187, Findings 133-34.] Royalties are based on the value of the natural gas produced at the wellhead. [RP 201, Finding 267.]<sup>3</sup> In 2007 UMUT oil and gas royalties totaled \$4,426,741.00, mostly from the New Mexico Lands. [RP 201, Finding 271.] They are distributed to tribal members on a *per capita* basis. [RP 201, Finding 270.] Since 1983 the Tribe has also imposed taxes on Reservation oil and gas development, and the Tribe uses this revenue to defray its costs of providing basic governmental services to tribal members. [RP 202, Findings 272-78.]

The State of New Mexico imposes five taxes on oil and gas development on the New Mexico Lands: an Oil and Gas Severance Tax, an Oil and Gas Conservation Tax, an Oil and Gas Emergency School Tax, an Oil and Gas Ad Valorem Production Tax, and an Oil and Gas Ad Valorem Production Equipment

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<sup>3</sup> The Statement of Facts in the Opening Brief contains a lengthy footnote 2 asserting that oil and natural gas produced on the Reservation "has no discernible value" until it is processed off of the Reservation. (Opening Br. 8.) However, no finding of fact of the District Court supports that proposition, and as explained in Section IV(C)(2) of the Argument below, this assertion is untrue.

Tax. [RP 195, Finding 213.] The revenues from these taxes go variously to meet the State's debt obligations, are put into the General Fund, are allocated to local governments (not including UMUT), and are used to pay for plugging abandoned wells.<sup>4</sup> [RP 196-97, Findings 222, 224, 227, 229, 232.] The State offers tax credits for wells drilled on tribal lands since July 1, 1995. [RP 197-98, Findings 234-39.] Under the Intergovernmental Production Tax Credit, if the Tribe increases its tax rate, the State reduces the operator's credit by the amount of the tribal tax increase. [RP 198, Finding 243.] For the years 2002-2007 the aggregate of the five New Mexico taxes on oil and gas production on the New Mexico Lands totaled \$8,052,449.00, or a yearly average of over \$1.3 million. [RP 204, Finding 293.]

The District Court found that these five taxes impose an economic burden on the Tribe and its members in a number of respects. [RP 206, Finding 310.] Without the New Mexico tax, oil and gas operators could seek to increase production on the New Mexico Lands by discovering new sources of oil and gas, by drilling infill wells on existing pools, or by bringing back into production wells that are not profitable under the current taxes. [RP 205, Finding 299.] The increase in production through discovery of new sources of oil and gas would increase UMUT revenue from royalties and the current taxes. [RP 205, Finding

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<sup>4</sup> NMOCD offers to plug abandoned wells on the New Mexico Lands but there is no evidence it has ever done so. [RP 199, 200, Findings 247, 259.]

300.] Increased production through infill or reopening closed wells on pools that lie within the New Mexico Lands would also increase UMUT revenue. [RP 205, Finding 301.] And if the Tribe were to impose the taxes which the State now imposes on Reservation oil and gas operators, as authorized by Council Resolution No. 3874 [RP 271], it would gain at least \$1.3 million per year, which would increase tribal revenue from all sources (\$16,052,092.00 in 2007 [RP 205, Finding 304]) by over 8 percent, or if that additional revenue were distributed *per capita*, the average annual income of tribal members would increase by \$650.00. [RP 204, Finding 297.]

The District Court also found, “[O]ther than opening its courts to the UMUT,<sup>5</sup> and offering plugging of abandoned wells, New Mexico provides no services directly to the UMUT [and] [t]here is no evidence in the record that members of the UMUT make use of services provided by New Mexico ...” [RP 199, Findings 248-49.]

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<sup>5</sup> The only example of this given by the District Court is the Tribe’s intervention in the San Juan River Basin general stream adjudication, New Mexico ex rel. State Engineer v. United States, Civil No. 75-184 in State District Court in San Juan County. [RP 199, Finding 246.] But the Tribe’s intervention was necessitated by the Supreme Court ruling that state courts have jurisdiction to adjudicate Indian reservation water rights by suing the United States pursuant to the McCarran Amendment, 43 U.S.C. § 666. C. River Water Conservation Dist. v. United States, 424 U.S. 800 (1976). Unless an Indian tribe intervenes to protect its own water rights, they will be adjudicated anyway, and “the right to refuse to intervene” is thus “dubious at best.” Arizona v. San Carlos Apache Tribe of Ariz., 463 U.S. 545, 567 n. 17 (1983).

## **SUMMARY OF ARGUMENT**

The Ute Mountain Ute Tribe asserts that the State of New Mexico is preempted from taxing the non-Indian oil and gas operators producing on the New Mexico Lands. The New Mexico Lands are uninhabited, and the District Court found the State of New Mexico provides no services on the New Mexico Lands.

In accordance with Supreme Court precedent, the courts engage in a “particularized inquiry” to determine whether state taxation of non-Indian operators on tribal lands is permissible. In carrying out this particularized inquiry the courts weigh the competing federal, tribal, and state interests. While courts may look at multiple factors, three factors have been given primary importance in the particularized inquiry: the comprehensiveness of federal regulation, economic harm to the tribe, and services provided by the state.

In its brief, the Ute Mountain Ute Tribe will demonstrate that the District Court correctly held that the taxes are preempted because the federal regulatory scheme is comprehensive, the five New Mexico taxes economically harm the Tribe, and the State of New Mexico provides no services that would justify this taxation. New Mexico’s only interest in the New Mexico Lands is a desire to raise revenue.

## **ARGUMENT**

### **I. STANDARD OF REVIEW.**

Both Homans and the Tribe accept the District Court's 311 findings of fact. (Opening Br. 20.) These findings may only be set aside if they are clearly erroneous. Fed. R. Civ. P. 52(a) (6); Four Sons Bakery Inc. v. Dulman, 542 F.2d 829, 832 (10th Cir. 1976); Cf. F.W. Hempel & Co., Inc v. Metal World, Inc., 721 F.2d 610, 611 n. 1 (7th Cir. 1983) (stating that, when neither party challenges a finding of fact, there is no reason for the reviewing court to deem it clearly erroneous). Appellate review of the District Court's conclusions of law is *de novo*. Cortez v. McCauley, 478 F.3d 1108, 1115 (10th Cir. 2007).

### **II. HISTORICAL BACKGROUND**

The Ute Mountain Ute Tribe has a long-standing relationship with the United States. The Ute Mountain Ute Tribe today consists of one band of Ute Indians, the Weeminuche Band. Since the first treaty in 1868<sup>6</sup> with the Confederated Utes, the tribal lands were reduced to where the Tribe is today.<sup>7</sup> [RP 175, Finding 4.] The New Mexico Lands were set aside for the Tribe by the Act of

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<sup>6</sup> Treaty Between the United States of America and the Tabeguache, Muache, Capote, Weeminuche, Yampa, Grand River, and Uintah Bands of Ute Indians, March 2, 1868, 15 Stat. 619. [RP 175, Finding 4.]

<sup>7</sup> Brunot Agreement, Act of April 29, 1874, 18 Stat. 37, and Act of June 15, 1880, 21 Stat. 199.

Congress in 1895. 28 Stat. 677. [RP 175, Finding 9.] The Tribe is a “domestic dependent nation” of the United States, Cherokee Nation v. Georgia, 30 U.S. 1, 17 (1831), and as such, enjoys the powers of self-governance free from state interference, including state taxation. McClanahan v. State Tax Comm’n of Ariz., 411 U.S. 164, 170-171 (1973). Congress has the exclusive power to regulate commerce with Indian tribes, id. at 172, and the United States Supreme Court has frequently recognized Congress’ authority to protect tribal immunity from state taxation. Moe v. Confederated Salish and Kootenai Tribes, 425 U.S. 463, 473 (1976). Only in very narrow circumstances may a state tax tribal commerce, such as oil and gas development, on tribal lands.

As discussed below, New Mexico imposes five state taxes on operators who, with the consent of the Tribe and the United States, sever oil and gas from the New Mexico Lands as part of the Tribe’s efforts to develop its oil and gas resources. Although the Tribe respects New Mexico’s sovereign authority to tax activities over which it has jurisdiction, the taxes in dispute are for activities occurring entirely within the boundaries of the Ute Mountain Ute Reservation and substantially interfere with the Tribe’s sovereign right to protect, utilize, and develop its resources.

### **III. UNITED STATES SUPREME COURT PRECEDENT ESTABLISHES A FLEXIBLE PREEMPTION ANALYSIS FOR DETERMINING WHETHER STATES MAY TAX NON-INDIANS DEVELOPING RESERVATION-CREATED RESOURCES.**

The controlling legal standard for assessing whether states may tax non-Indians engaging in on-reservation economic activities is set out in White Mountain Apache Tribe v. Bracker, 448 U.S. 136 (1980); Ramah Navajo School Bd., Inc. v. Bureau of Revenue of N.M., 458 U.S. 832 (1982); and adhered to in Cotton Petroleum Corp. v. New Mexico, 490 U.S. 163 (1989). In Bracker, the United States Supreme Court determined that the proper legal assessment of state taxation of non-Indian, on-reservation activity is to undertake a unique, federal Indian law preemption-based analysis. 448 U.S. at 144-45. This analysis is not “dependent on mechanical or absolute conceptions of state or tribal sovereignty,” but instead, looks at the important backdrop of tribal sovereignty and requires a “particularized inquiry into the nature of the state, federal, and tribal interests at stake.” Id. at 145. See [RP 209].

The Bracker Court used this “particularized inquiry” analysis to determine whether the State of Arizona could impose a motor carrier license tax and an excise fuel tax on a non-Indian company participating in the development of timber resources on the Fort Apache Reservation. Id. at 145-46. During the particularized inquiry analysis, the Bracker Court assessed the federal interest in reservation timber and roads, the White Mountain Apache Tribe’s interest in

making productive use of its timber, and Arizona's interest in the timber production. See id. at 145-151. [RP 209.] It first determined that the White Mountain Apache tribal timber development was governed by comprehensive federal regulations. Id. at 148. [RP 209.] Next, it determined that the economic burden of the state tax on the White Mountain Apache Tribe would interfere with the federal objective of providing the tribe with the benefits of its resources. Id. at 148-50. [RP 209.] Third, it determined that Arizona provided no regulatory function or service to the White Mountain Apache Tribe. Id. at 148-49. [RP 209.] Finally, it concluded that the state had only a "generalized interest in raising revenue" from the on-reservation economic activity. Id. at 150. [RP 209.] Thus, even though the Bracker Court acknowledged that the economic burden of the Arizona taxes was relatively small, it held that the balance of the interests favored the federal preemption of Arizona's taxes. See id. at 154 (Stevens, J., dissenting). [RP 209.]

Two years later, the Supreme Court expanded and clarified the Bracker particularized inquiry analysis to determine whether New Mexico could impose a gross receipts tax on a non-Indian construction company that was building a school for Indian children on reservation lands. Ramah, 458 U.S. 832. Again, the Court used the particularized inquiry analysis to balance the federal interests in promoting self-sufficiency in Indian education, the tribal interests in Indian

education, and the state interests in regulating and taxing federally-funded schools. See id. at 838. [RP 210.] In Ramah, New Mexico faced a history of extensive federal regulation of Indian educational facilities and express federal policy of encouraging self-sufficiency in Indian education. Id. at 839-42. To overcome the lack of State investment in and oversight of the Navajo schools, New Mexico argued that the services it provided to the construction company off the reservation and other, unrelated services it provided to the Navajo Nation were substantial and justified the imposition of the tax. Id. at 843-45. [RP 210.] The Ramah Court rejected both arguments, and held that, because New Mexico's only interest in the school construction was a general desire to raise revenue, the tax was preempted. Id. at 844-45 n. 9-10. [RP 210.]

Importantly for this case, in 1989 the United States Supreme Court upheld and applied the Bracker particularized inquiry analysis in the setting of New Mexico's oil and gas production taxes imposed on the Jicarilla Apache Indian Reservation. Cotton, 490 U.S. at 176 (confirming that the Supreme Court has "applied a flexible preemption analysis sensitive to the particular facts and legislation involved"). In Cotton—a Commerce Clause case brought not by a Tribe but by a producer seeking to free itself from both state and tribal taxes—the Supreme Court's examination confirmed that a traditional statutory preemption analysis alone is not appropriate without an examination of competing interests on

the reservation commerce in question. See id. Presented with a particular set of facts developed by the New Mexico state courts, the Cotton Court determined that, upon balancing the competing state, tribal, and federal interests, the state taxes were not preempted on the Jicarilla Apache Reservation. See id. at 185 (stating: “The factual findings of the New Mexico District Court clearly distinguish this case from both Bracker, supra, and Ramah Navajo School Bd., supra” and applying those factual findings to the law).

These cases set out the baseline for the flexible, particularized inquiry analysis used today to determine whether states may tax non-Indians engaging in on-reservation economic activities. In general, the first step in undertaking the particularized inquiry is to determine whether there is a comprehensive federal framework for regulation and management of the on-reservation activity and a strong history of active tribal participation within that framework. Ramah, 458 U.S. at 839-43; Bracker, 448 U.S. at 145-50; Cotton, 490 U.S. at 181-82 (analyzing the federal framework for Executive Order reservation oil and gas development). If so, that presence will demonstrate both strong federal and tribal interests and a strong backdrop of tribal sovereignty in the area of the taxed economic activity. See id.

Second, the state asserting its taxation jurisdiction must demonstrate a specific, legitimate regulatory interest in the reservation activity and must provide

substantial services related to that activity to justify any on-reservation taxation activity. Ramah, 458 U.S. at 843-45; Bracker, 448 U.S. at 150. Importantly, in this analysis, state provision of off-reservation services does not justify on-reservation taxation. Ramah, 458 U.S. at 844 n. 9. Finally, if the only state interest in the on-reservation activity is a general desire to raise revenue, that interest will be insufficient to overcome a comprehensive federal and tribal management scheme. Ramah, 458 U.S. at 845; Bracker, 448 U.S. at 150-51.

This particularized inquiry analysis has been consistently affirmed by the United States Supreme Court and the federal circuit courts since 1989. See, e.g., Wagon v. Prairie Band Potawatomi Nation, 546 U.S. 95, 101-02 (2005) (confirming that, while taxes placed on non-Indian, on-reservation activity can be preempted under the Bracker interest balancing test, a different test should be applied to off-reservation activity); New Mexico v. Mescalero Apache Tribe, 462 U.S. 324, 333-43 (1983) (applying the Bracker analysis to preempt state regulation and licensing of on-reservation hunting and fishing); Sac and Fox Nation of Missouri v. Pierce, 213 F.3d 566, 581-82 (10th Cir. 2000) (referencing Bracker but applying the off-reservation taxation analysis).

Cotton shows how a fundamentally different set of facts on a different reservation in New Mexico can result in a different legal conclusion; it does not control the outcome of the particularized inquiry as applied to taxation of non-

Indian oil and gas operators on the New Mexico Lands. Instead, the clear factual differences between this case and Cotton fully support the District Court's painstaking development of the uncontroverted findings of fact and its proper application of those facts to applicable federal law.

**IV. UNDER THE BRACKER PREEMPTION ANALYSIS, HOMANS IS PRE-EMPTED FROM ASSESSING THE FIVE OIL AND GAS TAXES.**

Under the Bracker preemption analysis, there are three reasons that Homans should be preempted from assessing the five oil and gas taxes. First, there is a strong background of Ute Mountain Ute Tribal sovereignty in the area of oil and gas regulation that has been carried forward into the comprehensive and exclusive scheme of federal and tribal regulation that exists on the New Mexico Lands today. Second, the five oil and gas taxes result in economic harm to the Tribe and its impoverished members and interfere with federal interests in the Tribe's oil and gas development. Finally, despite Homans' assertions, New Mexico does not provide the substantial services necessary to justify taxation of on-reservation activity. Thus, under the Bracker balancing test, the significant federal and tribal interests outweigh the state's *de minimis* on-reservation and off-reservation interests.

**A. Federal And Tribal Regulation Of Oil And Gas On The Ute Mountain Ute Reservation Is Comprehensive And State Regulation Is Unnecessary.**

**1. There Is A Comprehensive Scheme Of Federal And Tribal Regulation On The Ute Mountain Ute Reservation.**

- (a) There Is A Strong Backdrop Of Tribal Sovereignty From State Taxation Authority Over Oil And Gas Development On The New Mexico Lands.

Homans argues that there is “no tradition” of Ute Mountain Ute Tribal independence necessary to support the proposition that New Mexico state taxation of oil and gas operations have been preempted. (Opening Br. 44-45.) In short, Homans disagrees with the District Court’s conclusion that “[i]n this case, unlike in Cotton Petroleum, the historical backdrop of the UMUT’s tribal sovereignty is significant.” [RP 225.] The principal basis for Homans’ argument is that Congress long ago imposed state taxation on the Ute Mountain Ute Reservation. Homans argues:

In 1924 and 1927 Congress, in two separate statutes, explicitly pronounced that the production of oil and gas on Indian lands such as the Ute Mountain Ute tribal lands may be taxed by the state in which such lands are located. 25 U.S.C. § 398 and § 398a.

(Opening Br. 2, 46-47.) That statement is flatly wrong, and the District Court did not so hold. Indeed, if Homans is correct that Congress “explicitly” authorized New Mexico state taxation of oil and gas production on Indian lands, then there

would have been no point in the Supreme Court's particularized inquiry in Cotton, as Congressional intent would have been explicit.<sup>8</sup>

On their face, none of the statutes cited above apply to oil and gas leases on the New Mexico Lands. The tax provision of the 1927 Act, 25 U.S.C. § 398c (discussed in Cotton), applies only to “oil and gas wells ... upon lands within Executive Order Indian reservations,” which the Ute Mountain Ute Reservation is not. The 1924 Act, 25 U.S.C. § 398, is limited to 10-year mining leases on “[u]nallotted land on Indian reservations ... [under section 3 of the Act of February 28, 1891]...” The 1891 Leasing Act (25 U.S.C. § 397), referenced in the 1924 Act, applies by its terms only to lands “occupied by Indians who have bought and paid for the same, and which are not needed for farming or agricultural purposes...” This does not include the Ute Mountain Ute Reservation.

The New Mexico Lands were set aside by an Act of Congress on February 20, 1895, as part of the Ute Mountain Ute Reservation. 28 Stat. 677. [RP 175, Finding 9.] There was no oil and gas development on the Ute Mountain Ute

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<sup>8</sup> When Congress explicitly authorizes state taxation of mineral development on Indian lands, rather than leaving that issue for courts to decide, it knows how to do so. See, e.g., Section 3 of the Act of May 10, 1928, 45 Stat. 495, which states:

That all minerals, including oil and gas, produced on or after April 26, 1931, from restricted allotted lands of members of the Five Civilized Tribes in Oklahoma, or from inherited restricted lands of full-blood Indian heirs or devisees of such lands, shall be subject to all State and Federal taxes of every kind and character the same as those produced from lands owned by other citizens of the State of Oklahoma...

Reservation until the 1950s [RP 186, Finding 114], by which time the omnibus authorization of the IMLA had long been in place. As the Supreme Court held in Cotton, the IMLA neither authorized nor immunized oil and gas development on Indian lands from state taxation. Cotton, 490 U.S. at 177. But Homans argues that the Tribe “knew” when it began its oil and gas leasing program in the 1950s that state taxation was “explicitly authorized” by the 1924 Act. (Opening Br. 46-47.) For this assertion, Homans relies on British-American Oil Producing Co. v. Bd. of Equalization, 299 U.S. 159 (1936). That case involved an oil and gas lease on the Blackfeet Reservation, and the lease document itself recited that it was made pursuant to the 1891 Act. Id. at 161. Forty years later the Department of the Interior viewed the suggestion in British-American that the 1891 Act applied to all treaty reservations as *dicta*, noting that there was no dispute over the applicability of the 1891 Act to the pertinent oil and gas lease on the Blackfeet Reservation. 84 Interior Decisions 905, 906-08 (1977). In fact, there are no such leases on the Ute Mountain Ute Reservation, and no authority can be offered to show that the 1891 Act or the 1924 Act have any applicability to UMUT leases.<sup>9</sup>

In reality, Homans is making the ultimate bootstrap argument: that there is no tradition of tribal independence at the Ute Mountain Ute Reservation because

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<sup>9</sup> Thus, it is irrelevant whether the taxation authorization in the 1924 Act expired with the enactment of the IMLA in 1938, as stated in the Memorandum Opinion below [RP 225], and New Mexico’s argument to the contrary is also irrelevant.

the State of New Mexico began taxing oil and gas production in the 1950s. He can find no support for such taxation in applicable federal statutes. As mentioned, the IMLA did not speak to the issue. More recently, Congress has affirmatively endorsed tribal control over reservation mineral resources. In the IMDA, Congress authorized Indian Tribes to enter into joint venture and production-sharing agreements to develop their mineral resources. 25 U.S.C. § 2102(a). Tribes are thus no longer passive lessees awaiting their royalty payments. Indeed, the policy favoring tribal control is so strong that Congress placed an explicit “burden” on the Secretary of the Interior to justify any disapproval of a minerals agreement made pursuant to the IMDA. 25 U.S.C. § 2103(d). In 1994 the BIA promulgated regulations implementing the IMDA, which were

intended to ensure that Indian mineral owners are permitted to enter into minerals agreements that will allow the Indian mineral owners to have more responsibility in overseeing and greater flexibility in disposing of their mineral resources, and to allow development in the manner which the Indian mineral owners believe will maximize their best economic interest and minimize any adverse environmental or cultural impact resulting from such development.

25 C.F.R. § 225.1(a). Further, Section 6 of the IMDA provides that agreements made thereunder are “not subject to the [IMLA or] any other law authorizing the

development or disposition of the mineral resources of an Indian or Indian tribe.”

25 U.S.C. § 2105.<sup>10</sup>

Then in 2005 Congress enacted the Indian Tribal Energy Development and Self Determination Act of 2005 in Title V of the Energy Act, 25 U.S.C. §§ 3501-3504. The Act promotes the integration of energy resources on Indian lands by facilitating the construction of pipelines, electrical transmission facilities, refineries, and power plants thereon. Both the Secretary of the Interior and the Secretary of Energy are authorized to conduct grant and loan programs to assist tribes in achieving energy independence. Section 503 of the Energy Act specifically authorizes the making of grants to tribes “for (i) the development and enforcement of tribal laws (including regulations) relating to tribal energy resource development; and (ii) the development of technical infrastructure to protect the environment under applicable law ....” 25 U.S.C. § 3503(b)(1)(C). It is under the auspices of this broad congressional mandate that the federal agencies and the

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<sup>10</sup> The District Court cited language from a House Report, noting the Committee’s rejection of a proposed amendment to the IMDA submitted by the Governor of Montana which would have explicitly authorized state taxation of non-Indian activities in connection with mineral development under the IMDA, and the Committee’s reaction deferring to the U.S. Supreme Court’s “development of this area of the law.” [RP 221.] From that the District Court concluded that the IMDA did not “differ in any significant way from the IMLA.” [RP 221.] We disagree. The language of the Act itself makes it clear that the enactment of the IMDA was a step in the direction of tribal self-determination, freeing Indian tribes from the shackles of the anachronistic statutory authorizations of the past. That should weigh heavily in any Indian preemption analysis.

UMUT have developed a comprehensive regulatory scheme for oil and gas activities on the New Mexico Lands. It is in this spirit that the Tribe goes about developing its mineral resources, seeking true independence for its people.

(b) The Current Regulatory Scheme On The New Mexico Lands Is Comprehensive And Exclusive.

Under the federal Indian mineral leasing statutes, the federal government has enacted an extensive regulatory regime for oil and gas activities on Indian lands, and under this regulatory regime oil and gas development on the New Mexico Lands is a joint effort of the federal government and the Tribe. Recognizing this comprehensive regulatory scheme, the District Court correctly found that, when considered as a mixed question of law and fact, it is clear that the State of New Mexico does not regulate oil and gas operations on the New Mexico Lands, and that the federal regulations are therefore exclusive. [RP 228.] Homans' assertions that over the decades New Mexico has built and maintained an elaborate regulatory infrastructure and that this case is comparable to Cotton are incorrect. (Opening Br. 30, 52-54.) This Court should uphold the District Court's opinion which is supported by the regulations, the case law, and the facts, as discussed below.

As a preliminary matter, it is important to note that the federal regulations have been significantly enhanced since Cotton, which was decided in 1989. In 1994 the BIA promulgated the first set of regulations implementing the IMDA, an important new authorization of Indian mineral development that was not discussed

by the Supreme Court in Cotton, 59 Fed. Reg. 14971 (March 30, 1994); 25 C.F.R. Part 225.<sup>11</sup> Subsequently, in 1996 the BIA produced what it claimed were the first comprehensive regulations covering oil and gas leasing in 58 years. 61 Fed. Reg. 35634 (July 8, 1996). Further, in 2001 BLM added regulations focusing on drainage protection. 66 Fed. Reg. 1893 (January 10, 2001). Finally, on March 10, 2008, the BIA promulgated regulations in 25 C.F.R. Part 224 (73 Fed. Reg. 12808), implementing the Indian Tribal Energy Development and Self-Determination Act of 2005. These regulations “[e]stablish procedures by which a tribe, at its discretion, may enter into and manage leases, business agreements, and rights-of-way for purposes of energy resource development on tribal land ...” 25 C.F.R. § 224.10. These new regulations continue to expand the regulatory role of the federal agencies and the Tribe, making the current regulatory regime significantly different than the regulatory regime in Cotton. Accordingly, while the technical downhole instructions have largely remained in place over the past 25 years, Congress and the Department of Interior have deliberately placed in tribes ever greater authority over how oil and gas production is to be modeled.

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<sup>11</sup> Homans erroneously cites the 25 C.F.R. Part 225 regulations for the proposition that these were the same regulations which the Supreme Court reviewed in Cotton. (Opening Br. 56.) These regulations are not an “iteration” of old regulations, as asserted by Homans; they implement a new Act of Congress. The Opening Brief also states that these regulations “do not purport to be exclusive.” (Opening Br. 56.) That is also erroneous. Nothing in Part 225 mentions any state regulatory role. It does, however, cross-reference pertinent BLM and MMS regulations and functions, 25 C.F.R. §§ 225.4, 225.6.

Now, as detailed in 25 C.F.R. Parts 211 and 225, 43 C.F.R. Part 3160 and 30 C.F.R. Parts 202 and 206, the Tribe, BIA, BLM, and MMS work collaboratively to regulate every aspect of oil and gas development on the New Mexico Lands. While the entire regulatory scheme outlined in the Code of Federal Regulations is relevant to this case and demonstrates the extensiveness of federal and tribal regulation over oil and gas activities on Indian lands, a discussion of a few of the regulations combined with the relevant findings of fact validates the District Court's determination that the federal regulatory scheme is exclusive and distinguishes this case from Cotton.

The federal government has oversight over all pre-drilling activities. The BIA (in coordination with the Tribe) has authority to approve leases and authorize the operator to survey the land and create a survey road. [RP 187, Findings 129-30, 136.] 25 C.F.R. §§ 211.20, 225.22, 225.32. After obtaining UMUT consent for the survey, the BIA informs the BLM that the BIA has approved the survey. [RP 188, Finding 137.] After the operator has completed its survey, the operator submits an APD to the BLM. [RP 188, Finding 138.] Under federal law, the BLM and BIA share exclusive responsibility for approval of an APD; the BLM has final authority, but does not approve an APD until it has received a letter of concurrence from the BIA. [RP 188, Finding 142.] 43 C.F.R. § 3162.3-1.

In contrast to Cotton, where the state regulated well spacing, the BLM retains full authority over spacing on the New Mexico Lands. 493 U.S. at 186. [RP 229 (BLM exercises primary authority over well spacing on the New Mexico Lands).] The federal regulations provide that the BLM regulates well spacing on the New Mexico Lands. See 43 C.F.R. § 3162.3-1(a) (well shall be drilled in conformity with an acceptable well-spacing program that has been approved by the authorized officer after appropriate environmental and technical reviews). Accordingly, the BLM issued two orders (Ute Mountain Ute No.1 (1995) and Ute Mountain Ute No. 2 (1996)) setting well-spacing and pooling units for wells on the Ute Mountain Ute Reservation. [RP 192, Findings 183, 190.]<sup>12</sup> While the BLM did adopt an historic New Mexico state spacing standard when it entered into a now-expired MOU with the State of New Mexico, the BLM never relinquished regulatory authority over spacing on the New Mexico Lands. Since the expiration of the MOU the BLM has continued to determine spacing and drilling sites in accordance with Ute Mountain Orders No. 1 and No. 2.

In contrast to Cotton, where the district court found that the state regulated mechanical integrity, in this case the BLM regulates the mechanical integrity of

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<sup>12</sup> The BLM found that the specified well spacing would “prevent the waste of oil and gas,” “protect the correlative rights of all parties concerned,” and “insure proper and efficient development and promote conservation of the oil and gas resources of the [UMUT].” See [RP 192, Finding 186] (quoting Ute Mountain Ute Order No. 1).

wells on the New Mexico Lands. 490 U.S. at 185-86. The federal regulations authorize the BLM to regulate the mechanical integrity of wells. 43 C.F.R. § 3162.3-2 requires BLM approval before commencement of operations that could potentially impact the mechanical integrity of the well (such as re-drilling, deepening, or perform casing repairs). This regulation is important because it confers broad authority to the BLM to ensure the mechanical integrity of the wells. In addition to 43 C.F.R. § 3162.3-2 there are many other regulations that help ensure well safety and prevent contamination of fresh water aquifers. See e.g., 25 C.F.R. § 211.47, 43 C.F.R. §§ 3161.2, 3162.1, 3162.5-1, 3162.5-2, 3162.5-3.

The regulations also ensure that well development and drilling is carried out with due regard for the prevention of waste and injury. The comprehensive federal regulatory framework is designed to protect correlative rights, the resource, and the environment. 43 C.F.R. § 3162.1 (requiring the operator to assure maximum economic recovery of oil and gas by minimizing waste and adverse effects on ultimate recovery of other mineral resources); 43 C.F.R. § 3162.3-1(e) (each drilling plan should describe expected hazards, and proposed mitigation measures to address such hazards); 43 C.F.R. § 3162.5-1 (operator shall conduct operations in a manner which protects the mineral resources, other natural resources, and environmental quality). The federal regulations discussed above, in conjunction

with the case law and the District Court's findings of fact, establish that New Mexico plays no substantive regulatory role on the New Mexico Lands.

(c) The Case Law Establishes That Federal Government Has A Mechanism To Resolve Disputes.

The District Court's holding that the federal regulatory scheme is exclusive is also supported by Interior Board of Land Appeals ("IBLA") case law. Homans asserts that the State provides a process for resolving disputes. (Opening Br. 52.) However, the IBLA has already confirmed that BLM regulations provide a mechanism for resolving disputes and that, under the modern regulatory regime, it is the BLM that retains authority over spacing decisions on Indian lands.

In San Juan Citizens Alliance et al., 129 I.B.L.A. 1 (1999), an oil and gas company with a lease on tribally-owned lands within an Indian Reservation filed an application with the Colorado Oil and Gas Commission ("COGC") for a change of the existing spacing. The COGC denied the application. After reviewing the evidence presented before the COGC, the Associate State Director of the Colorado BLM issued a decision approving the application. An environmental group appealed the State Director's approval. The IBLA found that, in accordance with 43 C.F.R. 3162.3-1(a)<sup>13</sup>, the BLM makes the final pronouncement on the spacing

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<sup>13</sup> 43 C.F.R. § 3162.3-1(a) provides that an oil and gas well shall be drilled "in conformity with an acceptable well-spacing program." The regulation further provides in relevant part that such program is either "one which conforms with a spacing order or field rule issued by a State Commission or Board and accepted by

of oil and gas wells on Indian lands and that BLM's authority included the ability to overrule the COGC's spacing order. 129 I.B.L.A. at 3-5.

The IBLA also confirmed that the BLM's administrative review procedures permit a party aggrieved by either approval of a well-spacing application or approval of an APD to appeal that decision to the IBLA and that an aggrieved party could include environmental groups or others concerned about the potential impacts to air and groundwater quality. *Id.* at 4-5.

**2. Federal and Tribal Regulation Of Oil And Gas Development On The Reservation Leaves No Room Or Necessity For State Regulation Or Interference.**

Despite the District Court's determination that New Mexico does not regulate oil and gas operations on the New Mexico Lands and that the federal regulations are therefore exclusive [RP 228], Homans makes several assertions to the contrary. These assertions are addressed below.

**(a) NMOCD's Dispute Resolution Process Is Unnecessary.**

One of the regulatory functions Homans claims to offer operators on the New Mexico Lands is access to New Mexico's administrative process for resolving disputes between operators. (Opening Br. 52.) However, the District Court found that there is no evidence that operators have used the NMOCD hearing process to resolve disputes concerning extraction on the New Mexico Lands. [RP 200,

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the authorized officer" or "any other program established by the authorized officer."

Finding 252.] Further, as noted by the District Court, NMOCD's administrative efforts are unnecessary for resolving disputes over oil and gas development on the New Mexico Lands because the BLM already has an adjudicative process to resolve such disputes, including the right to administrative review and appeal. [RP 190, Findings 168-70.] [RP 230.] The District Court's findings are supported by the decision in San Juan Citizens Alliance et al and the federal regulations which specifically allow for such appeal. 43 C.F.R. §§ 3160.0-1; 3160.0-2; 3162.3-1(a); 3165.4(a).

- (b) New Mexico's Hearing Process Is So Rarely Utilized That It Cannot Support A Finding That New Mexico Materially Contributes To The Success Of The Tribe's Oil And Gas Program.

Homans also notes that New Mexico holds administrative hearings and approves requests for commingling and non-standard locations. (Opening Br. 52.) While the District Court did find that NMOCD has approved requests for non-standard locations and commingling [RP 200, Finding 253] when asked to by operators—and never the Tribe or the BLM—these hearings have been minimal. At trial New Mexico was only able to present six orders for the period of 1996-2006. [RP 602-05, 629-32, 717-19, 807-16, 847-52, 901-04, 999-1003.] Further, Mr. Hammond, Energy Director for the Tribe, testified that between 1950 to 2009, a period of 59 years, he was only able to locate a total of 25 hearing orders which purported to address production on the New Mexico Lands. [TR 48]. Finally,

NMOCD admits that the hearings rarely involve the appearance of a party disputing the request. [TR 376]. The minimal number of hearings over the years shows that New Mexico does not provide the valuable regulatory function of eliminating waste and protecting correlative rights.<sup>14</sup>

(c) NMOCD Is Not A Regulatory Partner with the BLM.

Homans asserts that the sharing of publicly available documents with BLM and the text of four<sup>15</sup> federal regulations creates a cooperative regulatory relationship between the BLM and NMOCD. (Opening Br. 56-57.) Homans states that New Mexico has a long-standing cooperative regulatory relationship with BLM, in recognition of their joint interests. (Opening Br. 56.) In support of this proposition, Homans notes first that the BLM initially processes APDs on the New Mexico Lands, and then sends the forms on to NMOCD for its approval; second, that relevant federal regulations invoke state law and remind the operator of the need to comply with state law; and third, that the BLM has reminded the Tribe of

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<sup>14</sup> Importantly, if excessive on-reservation drilling were to occur, New Mexico's expert testified that it would be easy for New Mexico to work with off-reservation operators to drill new offset wells to assure that correlative rights are protected. [TR 388.]

<sup>15</sup> The regulations cited by New Mexico include 43 C.F.R. § 3162.3-4. This regulation regards well abandonment and contains no references to the state or state law. New Mexico provides no discussion of why it believes this regulation invokes state law. Because New Mexico does not explain why it believes this citation is relevant, and the Tribe can discern no obvious connection to the argument, it will not be discussed further.

the availability of NMOCD's service of plugging and abandoning wells without charge. (Opening Br. 56- 57.) Each of these statements is refuted below.

As discussed above, by federal law only the BLM may approve an APD. 43 C.F.R. § 3162.3-1. Further, after several days of trial where New Mexico frequently contended it had to approve APDs, the District Court concluded that the BLM sends an APD to NMOCD only after BLM has already approved it. [RP 189, Finding 157.] The findings of fact also establish that it is the BIA, BLM, and the Tribe that consult regarding issues raised by APD applications. [RP 189, Finding 150.] While New Mexico can consult with operators and can engage the BLM in a technical discussion, it has no regulatory role.

Homans also asserts that relevant federal regulations invoke state law and remind the operator of the requirement to comply with the law. (Opening Br. 57.) However, this assertion is incorrect. For instance, 43 C.F.R. § 3162.2-2 addresses uncompensated drainage of federal or Indian mineral resources and provides that BLM will consider federal, state, and tribal rules, regulations, and spacing orders when determining what action to take. Similarly, 43 C.F.R. § 3162.3-1 provides that each well must be drilled in conformity with an acceptable well-spacing program for a surveyed well location approved or prescribed by the authorized officer who may consider spacing orders or field rules issued by a State Commission or Board. In these examples, the BLM is not required to follow state

regulations and orders, and may disregard them entirely. Consideration of state regulations and the option of adopting state spacing standards is simply not the same as invoking state law and reminding the operator of the need to comply with the law.

Finally, 43 C.F.R. § 3162.5-3 provides that compliance with health and safety requirements prescribed by the authorized officer shall not relieve the operator of the responsibility for compliance with other pertinent health and safety requirements under applicable laws or regulations. Compliance with the authorized officer's orders does not nullify or supersede other federal laws and regulations, and the applicability of state law would have to be made on a case-by-case basis depending on the state's jurisdiction.

In regards to plugging and abandoning, although New Mexico utilizes a modest portion of the tax revenues obtained from tribal oil and gas development for the plugging and abandoning of wells, NMOCD has never actually plugged an abandoned well on the New Mexico Lands. [RP 199, Finding 247.] Because the only state expenditure that is ever committed for a particular well is the expense for plugging that well [RP 200, Finding 259], NMOCD cannot identify any specific expenditure related to the wells on the New Mexico Lands. New Mexico's offering of a service that has never been utilized fails to support its assertion of a joint cooperative regulatory relationship with the BLM.

- (d) Both The Findings Of Fact And Federal Law Demonstrate That BLM And The Tribe, Not New Mexico, Regulate Environmental Issues On The New Mexico Lands.

Homans raises several environmental issues in an attempt to assert that New Mexico has a regulatory interest on the New Mexico Lands. In the Opening Brief, Homans notes that oil and gas operations can cause groundwater contamination and can disrupt the surface, which may cause environmental effects. (Opening Br. 17.) However, the District Court found that in this case there is no evidence in the record of actual or potential contamination of groundwater or potential environmental effects on adjoining private, state, federal, or tribal lands from oil and gas operations on the New Mexico Lands. [RP 191, Findings 178, 180.] Indeed, as discussed above, the federal regulations provide specific authority for the BLM to act to protect groundwater and the environment. 43 C.F.R. §§ 3162.5-1, 3162.5-2, 3162.3-2.

Despite these findings and regulations, New Mexico notes that BLM has recently approached NMOCD to discuss a potential problem with H<sub>2</sub>S gas. (Opening Br. 58 n. 6.) However, Congress has delegated BLM, not New Mexico, the authority to require operators to perform operations and maintain equipment in a safe and workmanlike manner, and this authority allows BLM to address any potential problems with H<sub>2</sub>S gas. 43 C.F.R. § 3162.5-3. Further, mere

consultation with the state is not equivalent to delegation of regulatory authority from the federal government to the state.

Next, Homans states that New Mexico has built and maintained an elaborate regulatory infrastructure, including environmental clean-up. (Opening Br. 52.) It is true that on one occasion in the late 1980's NMOCD became involved in one clean up on the New Mexico Lands and that NMOCD's involvement included having the operator cleanup a spill to NMOCD standards and inspecting the site to confirm the work. [RP 181, Finding 66.] However, in recent times, the Tribe's Department of Energy has assumed responsibility for detecting spills: once a spill is detected, the Department asks the operator and the BLM to cleanup the spill [RP 181, Finding 67], and the Tribe generally does not make use of New Mexico's environmental cleanup and site inspection [RP 199, Finding 250].

The federal regulations authorize the BLM to take actions to prevent environmental harm on the New Mexico Lands and to address environmental issues as they arise. The district court's opinion reflects that the BLM and the Tribe are in fact managing environmental issues on the New Mexico Lands without the assistance of NMOCD. [RP 233.] The findings of fact and the federal regulations simply do not support the State's assertion that it has an environmental regulatory interest, or in any way contributes to environmental regulation, on the New Mexico Lands.

(e) Administrative Paperwork Provided By BLM And Operators To NMOCD Does Not Endow NMOCD With Regulatory Authority.

Finally, Homans asserts that operators must comply with New Mexico's regulatory statutes and administrative regulations. Homans states that operators make all required filings and avail themselves of the hearing and administrative processes offered by NMOCD, and that if a given operator were to become non-compliant NMOCD would have the power to enforce its regulations without going onto the Reservation. (Opening Br. 53.)

Because New Mexico has no contact with the BIA and limited contact with the BLM and the Tribe [RP 189, 194-95, Findings 156, 207, 209], it is left to contend that it regulates the New Mexico Lands by policing operators under state rules that cannot reach the Ute Mountain Ute Reservation. As stated in the District Court opinion, if BLM chose to ignore a New Mexico regulation or order and enforce its own regulation or order and NMOCD tried to enforce its conflicting regulation or order, NMOCD would immediately run afoul of the Supremacy Clause. "Although NMOCD has a certain amount of power over the operators, it cannot use that power to acquire jurisdiction over the New Mexico lands." [RP 230.]

In conclusion, when taken as a mixed question of law and fact, New Mexico simply fails to demonstrate that it plays any regulatory role on the New Mexico

Lands. In this case, unlike Cotton, there is simply no regulatory role for the State. Therefore, this Court should uphold the District Court's determination that the federal regulatory scheme is exclusive and that the five New Mexico taxes are therefore unjustified. As discussed below, these unjustified taxes result in significant harm to the Tribe.

**B. The New Mexico Taxes Result In Economic Harm To The Tribe And Interfere With Federal Interests.**

In carrying out the Bracker preemption analysis, courts have previously recognized that state taxation that results in economic harm to the Tribe interferes with federal objectives. Bracker, 448 U.S. at 149-50. In this case, the District Court found that the Tribe and its members suffer economic harm as a result of the imposition of the five New Mexico taxes. [RP 206, Finding 310.] This economic harm interferes with the federal purposes of promoting tribal exploitation of on-reservation oil and gas resources and increasing tribal revenues. Cotton, 190 U.S. at 187; Kenai Oil and Gas, Inc. v. Dep't of Interior, 671 F.2d 383, 384 (10th Cir. 1982). Homans trivializes the District Court's findings by accusing the Court of applying a simplistic "quantitative" test for purposes of determining if the State's five taxes caused economic harm to the Tribe. (Opening Br. 48.)

The District Court's finding of economic harm is supported by both the Tribe's and Homans' expert economists. Both Dr. Duffield, the Tribe's expert economist, and Dr. Tysseling, Homans' expert economist agreed that New

Mexico's taxes injure the Tribe and its members. Dr. Tysseling testified that he agreed that, in the absence of Resolution No. 3874, ridding the Ute Mountain Ute Reservation of the five New Mexico taxes would induce greater production. [TR 176, 431-32.] Dr. Tysseling further acknowledged that all things being equal the tax revenues paid to the State would otherwise go to the Tribe. [TR 430-31.] This concurs with Dr. Duffield's testimony that the state taxes "squeeze the profit that remains for the tribe to exploit." [TR 184.] Further, Dr. Duffield concurred with Dr. Tysseling in finding that a decrease in taxes would increase production. [TR 176.]

The District Court also found that, if New Mexico taxation ceases, the Tribe could increase its tax rate, as authorized by Resolution No. 3874 [RP 271], or maintain its tax rate in order to stimulate production [RP 204-05, Findings 292, 298]. The District Court found that, if the New Mexico taxes were found unlawful, the market for oil and gas remained stable, and Resolution No. 3874 was implemented, the Tribe could receive at least \$1,300,000 per year in additional revenue. [RP 204, Finding 297.] This amount would substantially enhance tribal revenues, which total approximately \$16 million per year from all sources. [RP 205, Finding 304.] Finally, the District Court found that increased production through discovery of new sources of oil and gas or through infill or reopening of closed wells would increase the Tribe's revenues. [RP 205, Findings 300-01.]

In response to the District Court's findings and the expert testimony, Homans posits that the Tribe cannot have suffered sufficient harm from the taxes because the tax rate imposed on the operators on the New Mexico Lands is "slightly lower" than the rate imposed on Cotton Petroleum when it challenged the same taxes over 20 years ago. (Opening Br. 3.)<sup>16</sup> This ignores the fact, discussed infra at IV(C), that, unlike Cotton, the State of New Mexico provides *de minimis* services on the New Mexico Lands. Further, with this argument Homans is inviting this Court to engage in the same kind of "quantitative analysis" that Homans faults in the Opening Brief. (Opening Br. 48-49.)

Indeed, Homans argues that the tax rate is "slightly lower" because the State Legislature enacted tax credits available for wells drilled on tribal lands after July 1, 1995, but this assertion fails to account for another of the District Court's important factual findings.

Under the Intergovernmental Production Tax Credit, if the UMUT increases its taxes on operators extracting oil and natural gas from the New Mexico lands, the State of New Mexico credit to those operators will be reduced by the amount of the UMUT tax increase...

[RP 198, Finding 243.] Thus, for wells drilled after July 1, 1995, the Intergovernmental Production Tax Credit offered by New Mexico actually

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<sup>16</sup> The decision below does not contain a finding of fact to this effect, but it does discuss the tax credits, enacted after the Supreme Court's ruling in Cotton Petroleum, which evidently account for the "slightly lower" tax rate. [RP 197-99, Findings 234-44.]

*penalizes* Indian tribes who seek to increase revenue from oil and gas production, since a tribal tax increase would result in a concomitant reduction in the Intergovernmental Production Tax Credit available to operators on the New Mexico Lands. This imposes multiple burdens on tribal governments. Because increased production would result in increased revenue for the Tribe, this effect is a *direct* economic burden on the Tribe [RP 205-06, Findings 300, 310], and is a disincentive to all new drilling on the New Mexico Lands, as found by the District Court.

Homans also asserts that the Tribe can increase its taxes while still burdened with state taxes without adversely affecting on-reservation oil and gas development. (Opening Br. 50.) Homans supports this assertion by citing to Cotton. (Opening Br. 50.) However, Homans does not put this reference to Cotton in its proper context, and in the process overlooks a crucial distinction between this case and Cotton. In Cotton, the Supreme Court noted that the district court found that no economic burden fell on the Jicarilla Apache Tribe by virtue of the state taxes and that the Jicarilla Apache Tribe could in fact increase its taxes without adversely affecting on-reservation oil and gas development. 490 U.S. at 172-73. In this case, as discussed above, the District Court found that there was an economic burden on the UMUT, and both expert economists concurred. Further, as noted in the District Court's opinion, the Jicarilla Apache Tribe was not a party

in Cotton, and the lessee, Cotton Petroleum, only presented evidence of the economic burden on it, and no evidence of the economic burden on the Jicarilla Apaches. In fact, Cotton Petroleum's multiple taxation and Commerce Clause claims, which depended on the burden being on the lessee, would have been weakened by presentation of evidence showing the taxes were passed on to the Jicarilla Apaches. [RP 226-27.] 490 U.S. at 169.

In conclusion, while Homans characterizes the District Court's findings as "quantitative," the District Court's multiple findings of economic harm are much more detailed than that, and are supported by both economists.

**C. The District Court Correctly Refused Homans' Arguments That Off-Reservation Record-Keeping And Regulation Of State Infrastructure Amount To Provision Of Substantial Services That Would Justify Taxation.**

Homans spends a significant portion of the Opening Brief rehashing stale arguments that New Mexico provides substantial services related to the oil and gas production on the New Mexico Lands. (Opening Br. 52-57.) First, Homans argues that this Court should reverse the District Court's *de minimis* on-reservation services finding of fact. (Opening Br. 53.) Second, Homans argues that the off-reservation services provided to the operators should have been factored into the District Court's preemption analysis. (Opening Br. 54.) However, these arguments were already soundly rejected by the District Court on the basis of both the well-analyzed findings of fact and well-settled principles of federal law. [RP

233-34.] In addition, these arguments inappropriately request this Court to eviscerate the Bracker preemption analysis. This section will address each faulty argument in turn.

**1. Homans Provides Only *De Minimis* Services To Oil And Gas Operators On The New Mexico Lands.**

As Homans recognizes, the District Court issued a finding of fact that the economic value of the services provided by New Mexico to operators on the New Mexico tribal lands is *de minimis*. (Opening Br. 53.) [RP 201, Finding 264.] This issue was thoroughly briefed and considered at the trial level, and this finding is well-supported by the record and other findings of fact. [RP 199-200, Findings 245-54.] This Court should uphold the District Court's finding of *de minimis* on-reservation services.

**(a) Homans Is Precluded From Challenging The District Court's Findings Of Fact.**

At the outset, Homans is precluded from challenging finding of fact 264 and the other relevant findings of fact because he stipulated to all of the District Court's 311 findings of fact in the Opening Brief. (Opening Br. 20 ("The appellant [Homans] does not take issue with the trial court's findings of fact.")) That stipulation alone can end this Court's inquiry into the *de minimis* services finding.

Nonetheless, Homans attempts to circumvent finding of fact 264 by trying to re-litigate the magnitude of the services it provides on the New Mexico Lands.

Here, Homans first argues that taxation of the operators should be justified by the “elaborate regulatory infrastructure” of hearing and administrative processes, the state’s publicly available records, and the state’s environmental cleanup and site inspection services. (Opening Br. 52.) As more fully explained above in Section IV(A)(2), this argument directly contradicts the uncontroverted findings of fact that there is no evidence that either the Tribe or the BLM have used the hearing processes, the records, or the environmental cleanup and site inspection services. [RP 199, 200, Findings 245, 250, 252-54.] See also [RP 229-33].

Homans also argues that NMOCD’s paperwork requirements are a service provided by the State to the operators. (Opening Br. 54.) Again, as more fully explained above, these overlapping and unwelcome paperwork requirements do not demonstrate NMOCD has authority over the New Mexico Lands, and they cannot be characterized as state services that contribute in any way to the Tribe’s oil and gas development. Section IV(A)(2), supra.

(b) Homans’ Theoretical Services Argument Is Contrary To Well-Settled Federal Law.

Homans makes another attempt to reverse the *de minimis* finding by arguing that the State services are not measured by the *actual* services provided on the New Mexico Lands, but rather by some theoretical willingness to provide these services. (Opening Br. 55.) To support this, Homans inaccurately cites to the Commerce Clause analysis in *Cotton Petroleum*, and not to any applicable preemption

analysis. (Opening Br. 55 (citing Cotton Petroleum, 490 U.S. at 190).) Homans has not provided any other case law support for this novel “theoretical services” argument (and indeed, it cannot do so because such support does not exist).

Homans has no case law support because the “theoretical services” argument would eviscerate the balancing test set out in Bracker. The Bracker analysis is a factually-sensitive analysis that forces the reviewing court to assess and balance the actual interests and services at stake for the particular federal, tribal, and state entities involved. See, e.g., Barona Band of Mission Indians v. Yee, 528 F.3d 1184, 1190 (9th Cir. 2008) (noting the factual sensitivity of the test); Ramah, 458 U.S. at 843 (holding that the State’s actual declination to educate Indian children precluded it from imposing a burden on the comprehensive federal scheme); Cotton, 490 U.S. at 172 n. 7 (analyzing the actual State services provided to the Jicarilla Apache Tribe). If any state were able to tip the balancing test in its favor simply by offering services or regulation on reservation lands, the Bracker analysis would be turned on its head. In this factual context, any state offer to use its state-wide procedures on a reservation would nullify the presence of the relevant federal regulation and tribal in-house oil and gas regulation.

As it is, the Bracker analysis is a flexible but concrete analysis that is intended to assess the actual extent of competing management practices and

interest on tribal land. Accordingly, Homans' far-reaching argument that theoretical services justify on-reservation taxation is groundless.

**2. Homans' Regulation Of Off-Reservation Natural Gas Transportation Infrastructure Does Not Provide A Sufficient Basis For State Taxation Of Oil And Gas Production On The New Mexico Lands.**

Homans also attempts to circumvent the District Court's *de minimis* finding of fact by asserting that off-reservation regulation of the natural gas transportation and processing infrastructure provides a sufficient basis for the imposition of its on-reservation taxes. (Opening Br. 52-54, 57-59.)

**(a) Well-Settled United States Supreme Court Precedent Precludes Homans' Off-Reservation Benefits Argument.**

The first flaw in Homans' off-reservation benefits argument is a purely legal one: as the District Court correctly recognized, Homans' argument has already been conclusively precluded under well-settled United States Supreme Court precedent. See Ramah, 458 U.S. at 844 (stating that provision of off-reservation services is "not a legitimate justification for a tax whose ultimate burden falls on the tribal organization."); Mescalero Apache, 462 U.S. at 336 (stating that the exercise of state authority is based on "functions or services performed by the State in connection with the on-reservation activity"). See also [RP 234]. Homans suggests that this view has changed with the Supreme Court's decision in Cotton, where the Court observed that, "the relevant services provided by the State include

those that are available to the lessees and the members of the Tribe off the reservation as well as on it.” 490 U.S. at 189. However, the “relevant services” in that discussion pertained to Cotton Petroleum’s argument that the multiple tax burden violated the Commerce Clause, which is not at issue here. The quote is taken out of context, and the proposition that the rule of Ramah is no longer good law is incorrect.

(b) Homans’ Off-Reservation Argument Is Factually Inaccurate.

The second flaw in Homans’ argument is found in his interpretation of the District Court’s finding that “[w]ithout an off-reservation infrastructure in New Mexico to transport oil and gas, the economic value of the oil and gas produced on the New Mexico lands would be substantially less.” [RP 201, Finding 262.] Homans mischaracterizes this finding by stating that without the off-reservation infrastructure the oil and gas has “no discernable market value.” (Opening Br. 8, n. 2.) Of course, most Indian tribes are dependent upon the processing, transportation, and sale of their resources outside of their reservations because they have not had self-sustaining economies since colonization. If the value of off-reservation marketing and processing is relevant, then virtually *any* economic activity on an Indian reservation may be taxed by a state, but that has not been factored into the Supreme Court’s preemption analyses. Off-reservation benefits are simply irrelevant to a preemption analysis.

As for the assertion that the unprocessed oil and gas resources have “no discernible market value,” the federal regulations recognize that these resources *do* have significant value to the Tribe at the point of production on the New Mexico Lands. 30 C.F.R. Part 206. For instance, regardless of the actual price received for gas by a producer, the Tribe’s royalties are based upon a national index published by MMS that represents the average of sales within the region. This index value is applied to the volume of gas at the wellhead in order to determine the royalty value. As a result, the value of the gas for royalty purposes is not dependent on sale, and royalties can be assessed using the production volume, the MMS published index based value, the applicable royalty rate, and any allowable deductions per the regulations. The Tribe’s severance tax can be similarly assessed. Homans’ assertion that the oil and gas on the New Mexico Lands do not have value until processed is incorrect.

(c) Homans Can Recover The Cost Of Its Off-Reservation Services Through Its Off-Reservation Taxation Authority.

The Tribe recognizes the District Court’s finding that the off-reservation services to the operators are of substantial value to the Tribe. [RP 201, Finding 265.] Although the Tribe notes that Homans exaggerates the importance of these services (after all, Homans’ role is to regulate, and not to build or maintain the oil and gas processing infrastructure), it recognizes Homans’ right to tax them. Under Ramah, the proper way for Homans to collect revenues for off-reservation services

is to tax those off-reservation activities. Ramah, 458 U.S. at 845 n. 9 (stating “Presumably, the state tax revenues derived from [contractor’s] off-reservation business activities are adequate to reimburse the State for the services it provides to [contractor].”). See also [RP 234.]

Of course, New Mexico can impose taxes on the operators’ off-reservation activities. See, e.g., Gross Receipts and Compensation Tax, N.M. Stat § 7-9-1 et seq.; the Income Tax, N.M. Stat. § 7-2-1 et seq.; the Oil and Gas Proceeds Withholding, N.M. Stat. § 7-3A-1 et seq.; and the Natural Gas Processors Tax, N.M. Stat. § 7-33-4 et seq. These off-reservation taxes, like the taxes in Ramah, presumably reimburse New Mexico for the cost of the off-reservation services.

**D. The District Court Correctly Balanced The Relevant Federal, Tribal, And State Interests Under Bracker.**

Homans’ characterization of this case as “Cotton Petroleum revisited” ignores the Bracker preemption analysis. Homans attempts to shoehorn this case into the balancing test *conclusion* reached in Cotton by asserting, “[t]he only factual differences of significance between the instant case and Cotton Petroleum stem from the fact that the portion of the Ute Mountain Ute Reservation which is in New Mexico is unpopulated.” (Opening Br. 30.) However, this argument ignores the flexible, factually-sensitive preemption analysis developed in Bracker (and carried forth in Ramah, Mescalero Apache, and Cotton) and the District Court’s

painstaking work to analyze and balance the competing federal, tribal, and state interests at stake on the New Mexico Lands.

In both Bracker and Ramah, the Supreme Court found that the federal government had a significant interest in the tribal activity being taxed. Similarly, in this case, the federal government has a significant interest in the development of oil and gas resources on the New Mexico Lands. The federal government not only has a *responsibility* to regulate oil and gas production under the comprehensive scheme of federal regulations, but it *actually* implements that scheme effectively and exclusively on the New Mexico Lands. See Section IV(A)(1), supra. In contrast, in Cotton there was no finding of exclusivity; NMOCD conducted mechanical integrity inspections and protected correlative rights through an active well-spacing program. 490 U.S. at 185-86.

Here, unlike the Jicarilla Apache Tribe in Cotton, the Ute Mountain Ute Tribe has a strong history of tribal sovereignty in the area of oil and gas activity. See Sections II, IV(A)(1), supra. The Tribe has carried this history forward by working with the BLM, the BIA, and MMS to regulate oil and gas activities on the New Mexico Lands and to generate much-needed revenue for its impoverished membership. See Section IV(A)(1), supra. The success of the federal-tribal program has simply left no room (or need) for any state regulation or services. See

Section IV(A)(2), supra. In addition, the state taxes in this case (unlike the Cotton taxes) do cause economic harm to the Tribe. See Section IV(B), supra.

In this case, the District Court also recognized that the State has a relatively weak interest in the Tribe's on-reservation oil and gas development. Here, like Bracker and Ramah, Homans is providing no meaningful or substantial services, such as regulating spacing and mechanical integrity, on the New Mexico Lands. See Section IV(C), supra. As such, Homans' only real interest in the on-reservation oil and gas development activity is a general desire to raise revenue. Balancing this weak interest against the strong federal and tribal interests in oil and gas development on the New Mexico Lands, the District Court properly held that Homans' state taxes should be preempted.

## **V. CONCLUSION**

As sovereigns and as "domestic dependent nations," Indian tribes have historically enjoyed immunity from state taxation of tribal activities. However, this protection is not absolute, and in some cases non-Indian operators assisting tribes in on-reservation oil and gas development have been subject to state taxation. When applying the Bracker particularized inquiry test to the five New Mexico taxes assessed against operators assisting the Ute Mountain Ute Tribe in development of the Tribe's oil and gas resources, Homans' only interest is to collect revenue and the taxes are unlawful.

The State provides no benefit to the Ute Mountain Ute Reservation and State regulation of Tribal oil and gas development is not necessary; the federal regulatory scheme is comprehensive and is adequate to protect Tribal and non-tribal interests, the Tribe has a history of utilizing this federal regulatory scheme and opposing State interference, the State taxes burden the federal and Tribal interest in oil and gas development activities, and the services provided by the State that may justify the taxes are *de minimis*. For these reasons, the decision of the District Court must be affirmed.

Respectfully submitted,

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**CERTIFICATE OF COMPLIANCE**

As required by Fed. R. App. P. 32(a)(7)(c), I certify that this brief is proportionately spaced, in 14-point, Times New Roman pitch, and contains 11,381 words, including footnotes. I relied on my word processor to obtain this count, and it is MS Word 2003. I certify that this information is true and correct to the best of my knowledge and belief formed after a reasonable inquiry.

*s/Peter Ortego*

Peter Ortego

**CERTIFICATE OF SERVICE**

The undersigned hereby certifies that on this 16<sup>th</sup> day of February, 2010, the foregoing Brief of Plaintiff/Appellee was served on the following in the manner indicated:

Mr. Patrick Fisher, Clerk  
United States Court of Appeals for the Tenth Circuit  
Byron White U.S. Courthouse  
1823 Stout Street  
Denver, Colorado 80257  
(By electronic submission) (Original) and by Hand Delivery on February 17, 2010  
Seven Copies)

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s/Jennifer H. Weddle  
Jennifer H. Weddle, CO No. 32068

## **Rule 28(f) ATTACHMENTS**

### **Treaties/Statutory References**

1. 15 Stat. 619, Treaty Between the United States of America and the Tabeguache, Muache, Capote, Weeminuche, Yampa, Grand River, and Uintah Bands of Ute Indians, March 2, 1868.
2. 21 Stat. 199, Brunot Agreement, Act of April 29, 1874.
3. 18 Stat. 37, an Act of June 15, 1880.
4. 28 Stat. 677, February 20, 1895 Act of Congress.
5. 45 Stat. 495, Act of May 10, 1928.

### **Federal Statutes**

6. 25 U.S.C. §§ 396a-396g, Indian Mineral Leasing Act.
7. 25 U.S.C. § 397, 1891 Leasing Act.
8. 25 U.S.C. §§ 398, 398a, and 398c.
9. 25 U.S.C. §§ 2101, *et seq.*, Indian Mineral Development Act.
10. 25 U.S.C. §§ 3501-3506.
11. 43 U.S.C. § 666.

### **Code of Federal Regulations**

12. 25 C.F.R. Part 211
13. 25 C.F.R. Part 224
14. 25 C.F.R. Part 225
15. 30 C.F.R. Part 202

16. 30 C.F.R. Part 206
17. 43 C.F.R. Part 3160

## TREATY WITH THE UTE INDIANS. MARCH 2, 1868.

619

*Treaty between the United States of America and the Tabeguache, Muache, Capote, Weeminuche, Yampa, Grand River, and Uintah Bands of Ute Indians; (Concluded March 2, 1868; Ratification advised, with Amendment, July 25, 1868; Amendment accepted August 15, September 1, 14, 24, and 25, 1868; Proclaimed November 6, 1868.*

ANDREW JOHNSON,

PRESIDENT OF THE UNITED STATES OF AMERICA,

March 2, 1868.

TO ALL AND SINGULAR TO WHOM THESE PRESENTS SHALL COME, GREETING:

WHEREAS a treaty was made and concluded at the city of Washington, in the District of Columbia, on the second day of March, in the year of our Lord one thousand eight hundred and sixty-eight, by and between Nathaniel G. Taylor, Alexander C. Hunt, and Kit Carson, commissioners, on the part of the United States, and U-ré, Ka-ni-ache, An-ka-tosh, José-Maria, Ni-ca-a-gat, Guero, Pa-ant, Pi-ah, Su-vi-ap, and Pa-bu-ant, representatives of the Tabeguache, Muache, Capote, Weeminuche, Yampa, Grand River, and Uintah bands of Ute Indians, on the part of said Indians, and duly authorized thereto by them, which treaty is in the words and figures following, to wit:—

Preamble.

Contracting parties.

Articles of a treaty and agreement made and entered into at Washington City, D. C., on the second day of March, one thousand eight hundred and sixty-eight, by and between Nathaniel G. Taylor, Commissioner of Indian Affairs, Alexander C. Hunt, Governor of Colorado Territory and ex-officio superintendent of Indian affairs, and Kit Carson, duly authorized to represent the United States, of the one part, and the representatives of the Tabeguache, Muache, Capote, Weeminuche, Yampa, Grand River, and Uintah bands of Ute Indians, (whose names are hereto subscribed,) duly authorized and empowered to act for the body of the people of said bands, of the other part, witness:

ARTICLE I. All the provisions of the treaty concluded with the Tabeguache band of Utah Indians, October seventh, one thousand eight hundred and sixty-three, as amended by the Senate of the United States and proclaimed December fourteenth, one thousand eight hundred and sixty-four, which are not inconsistent with the provisions of this treaty, as hereinafter provided, are hereby reaffirmed and declared to be applicable and to continue in force as well to the other bands, respectively, parties to this treaty, as to the Tabeguache band of Utah Indians.

Certain provisions of former treaty reaffirmed.  
Vol. xiii. p. 678.

ARTICLE II. The United States agree that the following district of country, to wit: commencing at that point on the southern boundary line of the Territory of Colorado where the meridian of longitude 107° west from Greenwich crosses the same; running thence north with said meridian to a point fifteen miles due north of where said meridian intersects the fortieth parallel of north latitude; thence due west to the western boundary line of said Territory; thence south with said western boundary line of said Territory to the southern boundary line of said Territory; thence east with said southern boundary line to the place of beginning, shall be, and the same is hereby, set apart for the absolute and undisturbed use and occupation of the Indians herein named, and for such other friendly tribes or individual Indians as from time to time they may be willing, with the consent of the United States, to admit among them;

Reservation.

Boundaries.

Only certain persons to reside thereon.

and the United States now solemnly agree that no persons, except those herein authorized so to do, and except such officers, agents, and employes of the government as may be authorized to enter upon Indian reservations in discharge of duties enjoined by law shall ever be permitted to pass over, settle upon, or reside in the territory described in this article, except as herein otherwise provided.

Claims to all other lands released.

ARTICLE III. It is further agreed by the Indians, parties hereto, that henceforth they will and do hereby relinquish all claims and rights in and to any portion of the United States or Territories, except such as are embraced in the limits defined in the preceding article.

Two agencies on the reservation.

ARTICLE IV. The United States agree to establish two agencies on the reservation provided for in article two, one for the Grand River, Yampa, and Uintah bands, on White river, and the other for the Tabogauche, Meache, Weeminuche, and Capote bands, on the Rio de los Pinos, on the reservation, and at its own proper expense to construct at each of said agencies a warehouse or store-room for the use of the agent in storing goods belonging to the Indians, to cost not exceeding fifteen hundred dollars; an agency building for the residence of the agent, to cost not exceeding three thousand dollars; and four other buildings, for a carpenter, farmer, blacksmith, and miller, each to cost not exceeding two thousand dollars; also a school-house or mission building, so soon as a sufficient number of children can be induced by the agent to attend school, which shall not cost exceeding five thousand dollars.

Warehouse and other buildings.

School-house.

Water-power saw-mill.

The United States agree, further, to cause to be erected on said reservation, and near to each agency herein authorized, respectively, a good water-power saw-mill, with a grist-mill and a shingle-machine attached, the same to cost not exceeding eight thousand dollars each: *Provided*, The same shall not be erected until such time as the Secretary of the Interior may think it necessary to the wants of the Indians.

Indian agents to make their homes and reside where.

ARTICLE V. The United States agree that the agents for said Indians, in the future, shall make their homes at the agency buildings; that they shall reside among the Indians, and keep an office open at all times for the purpose of prompt and diligent inquiry into such matters of complaint, by and against the Indians, as may be presented for investigation under the provisions of their treaty stipulations, as also for the faithful discharge of other duties enjoined on them by law. In all cases of depredation on person or property, they shall cause the evidence to be taken in writing and forwarded, together with their finding, to the Commissioner of Indian Affairs, whose decision, subject to the revision of the Secretary of the Interior, shall be binding on the parties to this treaty.

Depredations.

Offenders among the whites.

ARTICLE VI. If bad men among the whites or among other people, subject to the authority of the United States, shall commit any wrong upon the person or property of the Indians, the United States will, upon proof made to the agent and forwarded to the Commissioner of Indian Affairs at Washington City, proceed at once to cause the offender to be arrested and punished according to the laws of the United States, and also reimburse the injured person for the loss sustained.

Wrongdoers among the Indians.

If bad men among the Indians shall commit a wrong or depredation upon the person or property of any one, white, black, or Indian, subject to the authority of the United States and at peace therewith, the tribes herein named solemnly agree that they will, on proof made to their agent and notice to him, deliver up the wrongdoer to the United States, to be tried and punished according to its laws, and in case they wilfully refuse so to do the person injured shall be reimbursed for his loss from the annuities or other moneys due or to become due to them under this or other treaties made with the United States.

Indians, heads of families, desirous to com-

ARTICLE VII. If any individual belonging to said tribe of Indians or legally incorporated with them, being the head of a family, shall desire to commence farming, he shall have the privilege to select, in the presence

## TREATY WITH THE UTE INDIANS. MARCH 2, 1868.

621

and with the assistance of the agent then in charge, by metes and bounds, a tract of land within said reservation not exceeding one hundred and sixty acres in extent, which tract, when so selected, certified, and recorded in the land book as herein directed, shall cease to be held in common, but the same may be occupied and held in exclusive possession of the person selecting it and his family so long as he or they may continue to cultivate it. Any person over eighteen years of age, not being the head of a family, may, in like manner, select and cause to be certified to him or her for purposes of cultivation a quantity of land not exceeding eighty acres in extent, and thereupon be entitled to the exclusive possession of the same as above directed.

mence farming,  
may select  
lands;  
tract to be re-  
corded and held  
in exclusive pos-  
session.

Persons not  
heads of fami-  
lies.

For each tract of land so selected a certificate containing a description thereof, and the name of the person selecting it, with a certificate endorsed thereon that the same has been recorded, shall be delivered to the party entitled to it by the agent after the same shall have been recorded by him in a book to be kept in his office, subject to inspection, which said book shall be known as the "Ute Land Book."

Ute Land  
Book.

The President may at any time order a survey of the reservation; and when so surveyed Congress shall provide for protecting the rights of such Indian settlers in their improvements, and may fix the character of the title held by each.

Survey, &c.

The United States may pass such laws on the subject of alienation and descent of property, and on all subjects connected with the government of the Indians on said reservation and the internal police thereof as may be thought proper.

Alienation and  
descent of prop-  
erty.

ARTICLE VIII. In order to insure the civilization of the bands entering into this treaty, the necessity of education is admitted, especially by such of them as are or may be engaged in either pastoral, agricultural, or other peaceful pursuits of civilized life on said reservation, and they therefore pledge themselves to induce their children, male and female, between the age[s] of seven and eighteen years, to attend school; and it is hereby made the duty of the agent for said Indians to see that this stipulation is complied with to the greatest possible extent; and the United States agree that for every thirty children between said ages who can be induced to attend school a house shall be provided, and a teacher competent to teach the elementary branches of an English education shall be furnished, who will reside among said Indians, and faithfully discharge his or her duties as teacher,—the provisions of this article to continue for not less than twenty years.

Education.

Children to at-  
tend school.

School-houses  
and teachers.

ARTICLE IX. When the head of a family or lodge shall have selected lands, and received his certificate as above described, and the agent shall be satisfied that he intends, in good faith, to commence cultivating the soil for a living, he shall be entitled to receive seeds and agricultural implements for the first year, not exceeding in value one hundred dollars, and for each succeeding year he shall continue to farm, for a period of three years more, he shall be entitled to receive seeds and implements as aforesaid, not exceeding in value fifty dollars; and it is further stipulated that such persons as commence farming shall receive instructions from the farmer herein provided for; and it is further stipulated that an additional blacksmith to the one provided for in the treaty of October seventh, one thousand eight hundred and sixty-three, referred to in article one of this treaty, shall be provided with such iron, steel, and other material as may be needed for the Uintah, Tampa, and Grand River agency.

Seeds and ag-  
ricultural imple-  
ments.

Instructions  
from farmer.

Additional  
blacksmith.

ARTICLE X. At any time after ten years from the making of this treaty, the United States shall have the privilege of withdrawing the farmers, blacksmiths, carpenters, and millers herein, and in the treaty of October seventh, one thousand eight hundred and sixty-three, referred to in article one of this treaty, provided for, but in case of such withdrawal, an additional sum hereafter of ten thousand dollars per an-

United States  
may withdraw  
farmers, &c.  
Vol. xiii. p. 673.

622

## TREATY WITH THE UTE INDIANS. MARCH 2, 1868.

622

num shall be devoted to the education of said Indians, and the Commissioner of Indian Affairs shall, upon careful inquiry into their condition, make such rules and regulations, subject to the approval of the Secretary of the Interior, for the expenditure of said sum as will best promote the educational and moral improvement of said Indians.

Clothing, blankets, &c.

ARTICLE XI. That a sum, sufficient in the discretion of Congress for the absolute wants of said Indians, but not to exceed thirty thousand dollars per annum, for thirty years, shall be expended under the direction of the Secretary of the Interior for clothing, blankets, and such other articles of utility as he may think proper and necessary upon full official reports of the condition and wants of said Indians.

Food, meats, and vegetables.

ARTICLE XII. That an additional sum sufficient, in the discretion of Congress, (but not to exceed thirty thousand dollars per annum,) to supply the wants of said Indians for food, shall be annually expended under the direction of the Secretary of the Interior, in supplying said Indians with beef, mutton, wheat, flour, beans, and potatoes, until such time as said Indians shall be found to be capable of sustaining themselves.

Cows and sheep.

ARTICLE XIII. That for the purpose of inducing said Indians to adopt habits of civilized life and become self-sustaining, the sum of forty-five thousand dollars, for the first year, shall be expended under the direction of the Secretary of the Interior, in providing each lodge or head of a family in said confederated bands with one gentle American cow, as distinguished from the ordinary Mexican or Texas breed, and five head of sheep; also one good bull for every twenty-five head of cows, and such further sums annually, in the discretion of Congress, as may be necessary, not to exceed forty-five thousand dollars per annum, and not for a longer period than four years, shall be expended as aforesaid to every lodge or head of a family that shows a disposition to preserve said stock for incense.

Part stricken out.  
Post, p. 623.

Railroads and highways to have right of way.

ARTICLE XIV. The said confederated bands agree that whensoever, in the opinion of the President of the United States, the public interests may require it, that all roads, highways, and railroads, authorized by law, shall have the right of way through the reservation herein designated.

Teachers and mechanics, and their support.

ARTICLE XV. The United States hereby agree to furnish the Indians the teachers, carpenters, millers, farmers, and blacksmiths, as herein contemplated, and that such appropriations shall be made from time to time, on the estimates of the Secretary of the Interior, as will be sufficient to employ such persons.

Cessions of reservations not to be valid, unless, &c.

ARTICLE XVI. No treaty for the cession of any portion or part of the reservation herein described, which may be held in common, shall be of any validity or force as against the said Indians, unless executed and signed by at least three fourths of all the adult male Indians occupying or interested in the same; and no cession by the tribe shall be understood or construed in such manner as to deprive, without his consent, any individual member of the tribe of his right to any tract of land selected by him, as provided in article seven of this treaty.

Appropriations, how to apply and be divided.

ARTICLE XVII. All appropriations now made, or to be hereafter made, as well as goods and stock due these Indians under existing treaties, shall apply as if this treaty had not been made, and be divided proportionately among the seven bands named in this treaty, as also shall all annuities and allowances hereafter to be made: *Provided*, That if any chief of either of the confederated bands make war against the people of the United States, or in any manner violate this treaty in any essential part, said chief shall forfeit his position as chief and all rights to any of the benefits of this treaty: *But provided further*, Any Indian of either of these confederated bands who shall remain at peace, and abide by the terms of this treaty in all its essentials, shall be entitled to its benefits and provisions, notwithstanding his particular chief and band may have forfeited their rights thereto.

Forfeitures by making war, &c.

Those at peace.

## TREATY WITH THE UTE INDIANS. MARCH 2, 1868.

623

In testimony whereof, the commissioners as aforesaid on the part of the United States, and the undersigned representatives of the Tabeguache, Muache, Capote, Weeminuche, Yampa, Grand River and Uintah bands of Ute Indians, duly authorized and empowered to act for the body of the people of said bands, have hereunto set their hands and seals, at the place and on the day, month and year first hereinbefore written:

Execution.

N. G. TAYLOR, [SEAL.]  
A. C. HUNT, Governor, &c., [SEAL.]  
KIT CARSON, [SEAL.]

Commissioners on the part of the United States.

U-RE, his x mark.  
KA-NI-ACHIE, his x mark.  
AN-KA-TOSH, his x mark.  
JOSE-MARIA, his x mark.  
NI-CA-A-GAT, or Greenleaf, his x mark.  
GUERO, his x mark.  
PA-ANT, his x mark.  
PI-AH, his x mark.  
SU-VI-AP, his x mark.  
PA-BU-SAT, his x mark.

## Witnesses:

DANIEL C. OAKES,  
U. S. Ind. Agent.  
LAFAYETTE HEAD,  
U. S. Indian Agent.  
U. M. CURTIS,  
Interpreter.  
H. P. BENNET,  
ALBERT G. BOONE,  
E. H. KELLOGG,  
W. J. GODFREY.

And whereas, the said treaty having been submitted to the Senate of the United States for its constitutional action thereon, the Senate did, on the twenty-fifth day of July, one thousand eight hundred and sixty-eight, advise and consent to the ratification of the same, with an amendment, by a resolution in the words and figures following, to wit:—

Ratification  
with amend-  
ment.

IN EXECUTIVE SESSION, SENATE OF THE UNITED STATES, }  
July 25, 1868. }

Resolved, (two thirds of the senators present concurring,) That the Senate advise and consent to the ratification of the articles of a treaty and agreement made and entered into at Washington City, D. C., on the second day of March, one thousand eight hundred and sixty-eight, between the United States and the Tabeguache, Muache, Capote, Weeminuche, Yampa, Grand River, and Uinta[h] bands of Ute Indians, with the following

## AMENDMENT:

ARTICLE XIII. Strike out the following words: "also one good bull for every twenty-five [head of] cows, and such further sums annually, in the discretion of Congress, as may be necessary, not to exceed forty-five thousand dollars per annum, and not for a longer period than four years, shall be expended as aforesaid to every lodge or head of a family that shows a disposition to preserve said stock for increase."

Amendment,  
Art. XIII.  
Ante, p. 622.

Attest:

GEO. C. GORHAM,  
Secretary.

624

## TREATY WITH THE UTE INDIANS. MARCH 2, 1868.

624

Amendment  
assented to.

And whereas the foregoing amendment having been fully explained and interpreted to certain duly authorized chiefs and headmen of the Tabeguache, Muache, Capote, Weeminuche, Yampa, Grand River, and Uintah bands of Ute Indians, they did, to wit: those of the Grand River and Uintah Ute Indians on the fifteenth day of August, in the year one thousand eight hundred and sixty-eight, those of the Yampas on the first day of September, in the same year, those of the Tabeguaches and Muaches on the fourteenth day of September, in the same year, those of the Capote Utes on the twenty-fourth day of September, in the same year, and those of the Weeminuche Utes on the twenty-fifth day of September, in the same year, give their free and voluntary assent to the said amendment in a writing, which, after reciting the aforesaid action of the Senate and its said proposed amendment, concludes in the words and figures following, to wit: —

Whereas the Senate of the United States has advised and consented to the ratification of the treaty made on the second day of March, one thousand eight hundred and sixty-eight, with the Tabeguache, Muache, Capote, Weeminuche, Yampa, Grand River, and Uintah bands of Ute Indians, with the following amendment, to wit: —

In Article XIII. strike out the following words: "also one good bull for every twenty-[five head of] cows, and such further sums annually, in the discretion of Congress, as may be necessary, not to exceed forty-five thousand dollars per annum, and not for a longer period than four years, shall be expended as aforesaid to every lodge or head of a family that shows a disposition to preserve said stock for increase."

Now, therefore, we, the chiefs and headmen of the aforesaid named bands of Ute Indians, duly authorized by our people, do hereby assent and agree to the said amendment, the same having been interpreted to us, and being fully understood by us.

Witness our hands and seals on the days and dates set opposite our names respectively.

Date of Signing.	Signatures.	Interpretation of Names.	Band
1868. Aug. 15	SAC-WE-UCH	his X mark. White Lock of Hair.	Grand River Ute Indians.
	TAH-NACH	his X mark. Granite Rock.	
	PAH-AH-PITCH	his X mark. Sweet Herb.	
	TAB-Y-OU-SOUCK-EN	his X mark. Sun Rise.	
	SHOU-WACH-A-WICKET	his X mark. Rain Bow.	
	PE-AH	his X mark. Black Tail Deer.	
	AB-UMP	his X mark. Pine Tree.	Uintah Ute Indians.
	AN-TRO	his X mark. Rocking.	
	PAH	his X mark. Water.	
	QUIR-NAUCH	his X mark. Eagle.	
	YAH-MAH-NA	his X mark. Briar.	

## TREATY WITH THE UTE INDIANS. MARCH 2, 1868.

625,

Signed in the presence of

A. SAGENDORF.

URIAH M. CURTIS, *Spec. Interpreter.*E. H. KELLOGG, *Secty. Col. Ind. Suptcy.*DANIEL C. OAKES, *U. S. Ind. Agent.*

LOUIS O. HOWELL.

Date of Signature.	Signature.	Interpretation of Names.	Band.
Sept. 1.	SA-WA-WAT-SE-WITCH	Blue River.	Tampe.
	COLORADO	Red, (Spanish.)	
	PA-ANT	Tall.	
	SU-RI-AP	Lodge Pole's Son.	
	NICK-A-A-GAH	Green Leaf.	

Signed in the presence of

E. H. KELLOGG, *Secretary Indian Superintendency Colorado Territory.*U. M. CURTIS, *Spec. U. S. Interpreter.*DANIEL C. OAKES, *U. S. Indian Agent.*

H. P. BENNET.

LOUIS O. HOWELL.

Date of Sigling.	Signatures.	Interpretation of Names.	Band.
Sept. 14.	OU-RAY	Arrow.	Tabogaches.
	SHIA-WA-NA	Blue Flower.	
	GUERO	Light Haired.	
	TAH-BE-WAH-CHE-KAH	Sun Rise.	
	AH-KAN-ASH	Red Cloud.	
	KA-NI-ACHE	One who was taken down.	Musches.
	AN-KA-TOSH	Red. (Ute.)	
	SAP-PO-WAN-E-RI		
	TU-SA-SA-RI-BE		
	NA-CA-GET	Son to Tu-sa-sa-ri-be.	
	YA-MA-AJ	or George.	

Signed in the presence of

WM. J. GODFREY.

DANIEL C. OAKES, *U. S. Ind. Agt.*EDWARD R. HARRIS, *Special Interpreter.*E. H. KELLOGG, *Secty. Col. Ind. Suptcy.*

LOUIS O. HOWELL,

URIAH M. CURTIS, *Interpreter.*

VOL. XV. TREAT. — 40

626

## TREATY WITH THE UTE INDIANS. MARCH 2, 1863.

626

To the other copy of these instruments are signed as witnesses the following names: Juan Martine Martines, (friend of Indians,) Albert H. Pfeiffer; (their old agent,) Manuel Lusero.

Date of Signing	Signature.	Interpretation of Names.	Band.
Sept. 21.	SO-BO-TA	his X mark. his X	Carpenter's Ute.
	I-SI-DRO	his X mark. his X	
	SOW-WA-CH-WICHE	his X mark. his X	
	BA-BU-ZAT	his X mark. his X	
	SAB-OU-ICHIE	his X mark. his X	
	CHU-I-WISH	his X mark. his X	
	I-TA-LI-UH	his X mark. his X	
	E-RI-AT-OW-UP	his X mark. his X	
	AA-CA-WA	his X mark. his X	
	AC-I-APO-CO-EGO	his X mark. his X	
	MARTINE	his X mark. his X	
	OU-A-CHEE	his X mark. his X	
	TAP-AP-O-WATIE	his X mark. his X	
	SU-VI-ATH	his X mark. his X	
	WI-AR-OW	his X mark. his X	

Signed in the presence of  
 LAFAYETTE HEAD.  
 ALB. H. PFEIFFER.  
 MANUEL LUSERO.  
 E. H. KELLOGG, Secty. Col. Ind. Suptcy.  
 URIAH M. CURTIS, Interpreter.  
 DANIEL C. OAKES, U. S. Ind. Agent.

Date of Signing.	Signatures.	Interpretation of Names.	Band.
Sept. 25.	PA-JA-CHO-PE	his X mark. his X	Tremaine's Ute.
	PA-NO-AR	his X mark. his X	
	SU-BI-TO-AU	his X mark. his X	
	TE-SA-GA-RA-POU-IT	his X mark. his X	
	SA-PO-EU-A-WA	his X mark. his X	
	QU-ER-A-TA	his X mark. his X	

TREATY WITH THE UTE INDIANS. MARCH 2, 1868.

627

Signed in the presence of

LAFAYETTE HEAD.

MANUEL LUSERO.

ALB. H. PFEIFFER.

E. H. KELLOGG, *Secty. Col. Ind. Suptcy.*

JUAN MARTINE MARTINES, *Interpreter and Indian's Friend.*

DANIEL C. OAKES, *U. S. Ind. Agent.*

URIAH M. CURTIS, *Interpreter.*

I hereby certify that, pursuant to the order from the Commissioner of Indian Affairs, dated August fourth, one thousand eight hundred and sixty-eight, I visited and held councils with the various bands of Ute Indians, at the times and places named in this instrument; and to all those familiar with the provisions of the treaty referred to have had the Senate amendment fully interpreted to them, and to all those not familiar with the treaty itself I have had the same fully explained and interpreted; and the forty-seven chiefs whose names are hereunto subscribed, placed their names to this instrument with the full knowledge of its contents and likewise with the provisions of the treaty itself.

Given under my hand at Denver, this fourteenth day of October, one thousand eight hundred and sixty-eight.

A. C. HUNT,

*Gov. Ex-off. Supt. Ind. Affairs.*

Now, therefore, be it known that I, ANDREW JOHNSON, President of the United States of America, do, in pursuance of the advice and consent of the Senate, as expressed in its resolution of the twenty-fifth day of July, one thousand eight hundred and sixty-eight, accept, ratify, and confirm the said treaty, with the amendment, as aforesaid.

*Proclaimed.*

In testimony whereof I have hereto signed my name, and caused the seal of the United States to be affixed.

Done at the city of Washington, this sixth day of November, in the [SEAL.] year of our Lord one thousand eight hundred and sixty-eight, and of the Independence of the United States of America the ninety-third.

ANDREW JOHNSON.

By the President:

WILLIAM H. SEWARD,  
*Secretary of State.*

April 29, 1874. **CHAP. 136.**—An act to ratify an agreement with certain Ute Indians in Colorado, and to make an appropriation for carrying out the same.

*Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,* That a certain agreement made by Felix R. Brunot, commissioner on the part of the United States, with certain Ute Indians in Colorado, be, and the same is hereby, ratified

## FORTY-THIRD CONGRESS. SESS. I. CH. 130. 1874.

37

and confirmed. Said agreement is in words and figures following, namely:

Articles of convention made and entered into at the Los Pinos agency for the Ute Indians, on the thirteenth day of September, eighteen hundred and seventy-three, by and between Felix R. Brunot, commissioner in behalf of the United States, and the chiefs, head men, and men of the Tabeguache, Muache, Capote, Weeminuche, Yampa, Grand River, and Uintah bands of Ute Indians, witnesseth:

Title.

That whereas a treaty was made with the confederated bands of the Ute Nation on the second day of March, eighteen hundred and sixty-eight, and proclaimed by the President of the United States on the sixth day of November, eighteen hundred and sixty-eight, the second article of which defines by certain lines the limits of a reservation to be owned and occupied by the Ute Indians; and whereas by act of Congress approved April twenty-three, eighteen hundred and seventy-two, the Secretary of the Interior was authorized and empowered to enter into negotiations with the Ute Indians in Colorado for the extinguishment of their right to a certain portion of said reservation, and a commission was appointed on the first day of July, eighteen hundred and seventy-two, to conduct said negotiation; and whereas said negotiation having failed, owing to the refusal of said Indians to relinquish their right to any portion of said reservation, a new commission was appointed by the Secretary of the Interior, by letter of June second, eighteen hundred and seventy-three, to conduct said negotiation:

Preamble.

Vol. xv, p. 619.

1872, ch. 115, vol. xvii, p. 55.

Now, therefore, Felix R. Brunot, commissioner in behalf of the United States, and the chiefs and people of the Tabeguache, Muache, Capote, Weeminuche, Yampa, Grand River, and Uintah, the confederated bands of the Ute Nation, do enter into the following agreement:

ARTICLE I. The confederated band of the Ute Nation hereby relinquish to the United States all right, title, and claim and interest in and to the following described portion of the reservation heretofore conveyed to them by the United States, viz: Beginning at a point on the eastern boundary of said reservation fifteen miles due north of the southern boundary of the Territory of Colorado, and running thence west on a line parallel to the said southern boundary to a point on said line twenty miles due east of the western boundary of Colorado Territory; thence north by a line parallel with the western boundary to a point ten miles north of the point where said line intersects the thirty-eighth parallel of north latitude; thence east to the eastern boundary of the Ute reservation; thence south along said boundary to the place of beginning: *Provided*, That if any part of the Uncopagre Park shall be found to extend south of the north line of said described country, the same is not intended to be included therein, and is hereby reserved and retained as a portion of the Ute reservation.

Relinquishment of lands.

Bounds

Proviso.

ARTICLE II. The United States shall permit the Ute Indians to hunt upon said lands so long as the game lasts and the Indians are at peace with the white people.

Hunting permitted.

ARTICLE III. The United States agrees to set apart and hold, as a perpetual trust for the Ute Indians, a sum of money, or its equivalent in bonds, which shall be sufficient to produce the sum of twenty-five thousand dollars per annum; which sum of twenty-five thousand dollars per annum shall be disbursed or invested at the discretion of the President, or as he may direct, for the use and benefit of the Ute Indians annually forever.

Annuitv.

ARTICLE IV. The United States agrees, so soon as the President may deem it necessary or expedient, to erect proper buildings and establish an agency for the Weeminuche, Muache, and Capote bands of Ute Indians at some suitable point, to be hereafter selected, on the southern part of the Ute reservation.

Agency to be established.

ARTICLE V. All the provisions of the treaty of eighteen hundred and sixty-eight not altered by this agreement shall continue in force; and

Provisions of treaty of 1868, not altered by this treaty, continued.

the following words, from article two of said treaty, viz, "The United States now solemnly agrees that no persons except those herein authorized to do so, and except such officers, agents, and employees of the Government as may be authorized to enter upon Indian reservations in discharge of duties enjoined by law, shall ever be permitted to pass over, settle upon, or reside in the territory described in this article, except as herein otherwise provided," are hereby expressly re-affirmed, except so far as they applied to the country herein relinquished.

Salary to head chief.

ARTICLE VI. In consideration of the services of Ouray, head chief of the Ute Nation, he shall receive a salary of one thousand dollars per annum for the term of ten years, or so long as he shall remain head chief of the Utes and at peace with the people of the United States.

Agreement subject to ratification.

ARTICLE VII. This agreement is subject to ratification or rejection by the Congress of the United States and of the President.

[SEAL.]

FELIX R. BRUNOT,  
Commissioner.

Attest:

THOMAS K. CREE, Secretary.  
JAMES PHILLIPS, M. D.,  
JOHN LAWRENCE, Interpreters.

Ouray, his x mark, principal chief.

Sapivaneri, his x mark.

Guero, his x mark.

Chavanau, his x mark.

Tosak, his x mark.

Chavis, his x mark.

Caronera, his x mark.

Kuchumpias, his x mark.

To-paaz, his x mark.

Haatechiek, his x mark.

Ta-va-na-serika, his x mark.

Vicente, his x mark.

Qua-tun-ut, his x mark.

McCook, his x mark.

Budalo, his x mark.

Paziuts, his x mark.

Valupe, his x mark.

Juan Antonio, his x mark.

Kiko, his x mark.

Sapaya, his x mark.

Satchuva, his x mark.

Tratz, his x mark.

Pasquah, his x mark.

Brunot, his x mark.

Arop, his x mark.

Corutz, his x mark.

Te-rantup, his x mark.

Acomuwep, his x mark.

Washington, his x mark.

Pe-ro, his x mark.

Patzie, his x mark.

Conejo, his x mark.

Azum-pilz, his x mark.

Antelope, his x mark.

Aiguillar, his x mark, M.

Alamon, his x mark, M.

Cocho, his x mark, T.

Qua-nusus, his x mark, T.

Te-sa-quent, his x mark, M.

Ta-va-une, his x mark, T.

Mnus, his x mark, M.

Peech, his x mark.

Acavut, his x mark.

Sium, his x mark.

Pasiz, his x mark.

Jose Maria, his x mark.

Aucatosh, his x mark.

Juan, his x mark.

John, his x mark.

Chavez, his x mark.

Curecanto, his x mark.

Parisio, his x mark.

Yanko, his mark.

Noawakit, his x mark, T.

Za-riwap, his x mark, T.

Ucauar, his x mark, T.

Comanche, his x mark, T.

Otois, his x mark, T.

Katzupin, his x mark, T.

Ta-ma-witchi, his x mark, T.

Kutzaporutz, his x mark, T.

Wais, his x mark, T.

Sepeis, his x mark, M.

Waponihatz, his x mark, T.

Zaparitzaz, his x mark, T.

Kuza Comanche, his x mark, T.

Nijeatz, his x mark, T.

Izazab, his x mark, T.

Charley, his x mark, T.

Apanton, his x mark, T.

Natnao, his x mark, T.

Aka, his x mark, T.

Ta-majo, his x mark, T.

Koapuitz, his x mark, T.

Quarupe, his x mark, T.

Ziah, his x mark, T.

Guatanar, his x mark, T.

Peonika, his x mark, T.

Akaiok, his x mark, T.

Regis, his x mark, T.

Poevis, his x mark, T.

Povociat, his x mark, T.

## FORTY-THIRD CONGRESS. SESS. I. CH. 136. 1874.

39

Patchuvuntz, his x mark, T.  
 Ochos Blankos, his x mark, M.  
 Kiratz, his x mark, T.  
 Wapauas, his x mark, T.  
 Martine, his x mark, M.  
 Manuel, his x mark, M.  
 Sa-mora, his x mark, M.  
 Penaritz, his x mark, T.  
 Wai-a-zitz, his x mark, T.  
 Jose Rapiet, his x mark, M.  
 Te-sa-quit, his x mark, M.  
 Taos, his x mark, M.  
 Onchatoz, his x mark, T.  
 Wa-na-zitzl-askitz, his x mark  
 Kewukpo, his x mark, M.  
 Christiano, his x mark, M.  
 Amacksiz, his x mark, T.  
 Sa-pu-utz, his x mark, T.  
 Ja-parka, his x mark, T.  
 Wan-koro, his x mark, T.  
 Beture, his x mark, T.  
 Cimmaron, his x mark, M.  
 Wa-nu-ponika, his x mark, T.

Lo-ro, his x mark, T.

Colorado, his x mark, T.

Cabresa-negro, his x mark, M.  
 We-utz, his x mark, T.

Tru-cha, his x mark, T.  
 Ator, his x mark, T.  
 Sa-pi-to-a-wick, his x mark, T.  
 Joe, his x mark, M.  
 Tug, his x mark, T.  
 Ne-bantro, his x mark, T.  
 Juan Martine, his x mark, M.

Ripis, his x mark, M.  
 Ligah, his x mark, T.  
 Yotoyora, his x mark, T.  
 Ka-moev, his x mark, T.  
 Avoa, his x mark, T.  
 Shavanakovant, his x mark, T.  
 Zanoarap, his x mark, T.  
 Pal-macuch, his x mark, T.  
 Tu-up-o-na-ritz, his x mark, T.  
 Ma-re-to, his x mark, T.  
 Tabere, his x mark, T.  
 Po-ka-ne-te, his x mark, T.  
 Pe-er-guert, his x mark, T.  
 Tugnop, his x mark, T.  
 Sapio, his x mark, T.  
 Po-wa-ra, his x mark, Chief of  
 Weeminuchex.

Wach-eup, his x mark, W.  
 Quasuach, his x mark, W.  
 Ca-re-sonach, his x mark, W.  
 Per-ca-ke-seach, his x mark, W.  
 A-wa-re-otz, his x mark, W.  
 E ta-quorum, his x mark, W.

Tabequachcut, his x mark, T.  
 Urso, his x mark, T.  
 Kerenomes, his x mark, T.  
 Acatewich, his x mark, T.  
 Aucatara, his x mark, T.  
 Bapter, his x mark, T.  
 Alzea-vi, his x mark, T.  
 Atzu, his x mark.  
 Panais, his x mark.  
 Capotavit, his x mark.  
 Ka-muck, his x mark.  
 Zisk, his x mark, M.  
 Te-putziet, his x mark, M.  
 Gii-puget, his x mark, T.  
 Ponlitz, his x mark, T.  
 Gagavavener, his x mark, T.  
 Waziap, his x mark.  
 Poova, his x mark.  
 Tamserik, his x mark.  
 U-vu-pitz, his x mark.  
 Acavit, his x mark.  
 Zarewich, his x mark.  
 Unca-nante, chief of Uncompagre,  
 Tab.

Wap-sop, his x mark, Chief of Un-  
 compagre, Tab.

Paga-na-chuck-chick, his x mark,  
 T.

Noart, his x mark, T.  
 Kancatche, his x mark, Chief of  
 Muacho.

To-mo-aset, his x mark, M.  
 Que-a-ra-nich, his x mark, M.  
 Siarch-a-kitz, his x mark, T.  
 Soamugenguaboa, his x mark, T.  
 To-sa-set-bequa, his x mark, T.  
 We-suc, his x mark, T.  
 To-sen-par-kinaquet, his x mark,  
 T.

Tuc-a-wa-be-quet, his x mark, T.  
 Sa-ach-chonc, his x mark, T.  
 Ka-ton-a-wac, his x mark, T.  
 Move-ga-ritz, his x mark, T.  
 Tup-o-so-a, his x mark, T.  
 So-wa-wick, his x mark, T.  
 Murato, his x mark, T.  
 Qua-cu-ritz, his x mark, T.  
 A-va-suip, his x mark, T.  
 Na-na-witz, his x mark, T.  
 Wa-ra-ta-zi, his x mark, T.  
 Ze-ap-ovaneri, his x mark, T.  
 Wap-pah-pi, his x mark, T.  
 Wo-naquit, his x mark, T.  
 No-ach-itz, his x mark, T.  
 Cow-a-ra-kuch, his x mark, T.

So-va-nor, his x mark, T.  
 Que-nach-i-viach, his x mark, T.  
 Archue, his x mark, T.  
 Armacos, his x mark, T.  
 Ourarch, his x mark, T.  
 Cal-chu-ma-char-kitz, his x mark,  
 T.

Sa-o-artz, his x mark, W.  
 Moar-ta-witz, W.  
 Moar-ta-to-quit, W.  
 Wa-wa-to-ez, W.  
 Snaph, Weeminuches sub-chief  
 Jose Mario, W.

Qu-a-sent, Uncomp. Tabequache.  
 Si-vich, Uncomp. Tabequache.  
 Si-vich-arch, Uncomp. Tabequa-  
 che.

Acca-ra-re, his x mark, M.  
 Manamara, his x mark, M.  
 Su-erup, his x mark, M.  
 So-coo, his x mark, M.  
 Nocovarts, his x mark, M.  
 Uparcarrartz, his x mark, M.  
 Opo-pa-ritz, his x mark, M.  
 Ouasiz, his x mark, T.  
 Perove, his x mark, T.  
 Etook, his mark, T.  
 Taberouer, his x mark, T.  
 Pah-sonc, his x mark, T.  
 Tera-na-take, his x mark, T.  
 To-siach, his x mark, T.  
 Cavarup, his x mark, T.

Sa-vah, his x mark, T.  
 Queazarts, his x mark, T.  
 Arrach, his x mark, T.  
 Arrup, his x mark, T.  
 Peach-sup, his x mark, T.  
 Sa-a-wip, his x mark, T.

Klize, his x mark, T.  
 Pereque, his x mark, T.  
 Uch-ca-mir, his x mark, T.  
 Uch-ca-poo-ritz, his x mark, T.  
 Uch-a-titz, his x mark, T.  
 To-ko-nantz, his x mark, Tab. sub-  
 chief.

Ko-chup-a-sitz, his x mark, T.  
 Ar-ca-va-ritz, his x mark, T.  
 Area-va-regua, his x mark, T.

Sha-va-qua-to-ark, his x mark, T.  
 We-ga-va, his x mark, T.  
 Sea-rach, his x mark, T.  
 So-o-moquit, his x mark, T.  
 Peareh, his x mark, T.  
 Coh-pa-rum, his x mark, T.  
 Tar-tach, his x mark, T.  
 Woh-chick-a-arp, his x mark, T.  
 Guero-muchich, his x mark, T.  
 Arpa-chitz, his x mark, T.  
 Yer-putz, his x mark, T.  
 Un-no-wartz, his x mark, T.  
 Su-te-queitz, his x mark, T.  
 Pasques, his x mark, M.  
 Jose Raphael, his x mark, Mua-  
 che, sub-chief.  
 Raphael, his x mark, M.  
 Ta rah-wah, his x mark, M.  
 Ka-qua-bah, his x mark, M.  
 Oe-bo-atz, his x mark, T.  
 Oro-bitz, his x mark, T.  
 Aca-une, his x mark, T.

We, the undersigned, were present at the signing of the articles of agreement with the Ute Indians, and are hereby witnesses to their marks.

THOMAS K. CREE, Secretary Special Ute Commission.

CHARLES ADAMS, United States Indian Agent.

OTTO MEARS.

THOMAS A. DOLAN.

STEPHEN A. DOLE.

Carwarwo, his x mark.  
 S. Obatah, his x mark.  
 Martine, his x mark.  
 Jose, his x mark.  
 Macosebu, his x mark.  
 Canhear, his x mark.  
 Mopuch, his x mark.  
 Warwah, his x mark.  
 Yahtanah, his x mark.  
 Mocatacher, his x mark.  
 Ocuponough, his x mark.  
 Couchewatab, his x mark.  
 Otocora, his x mark.  
 Picquogh, his x mark.  
 Quierager, his x mark.  
 Ojos Blancos, his x mark.  
 Cocuhupatche, his x mark.  
 Muecete, his x mark.  
 Cachapura, his x mark.  
 Navacartia, his x mark.  
 Murvon, his x mark.

Sabpowata, his x mark.  
 Pungase, his x mark.  
 Sevaro, his x mark.  
 Terrean, his x mark.  
 Ignacio, his x mark.  
 Juan Ancho, his x mark.  
 Cunespeche, his x mark.  
 Powincha, his x mark.  
 Towiar, his x mark.  
 Cabazon, his x mark.  
 Warhoup, his x mark.  
 Arvaach, his x mark.  
 Quaveroch, his x mark.  
 Sevacho, his x mark.  
 Segatah, his x mark.  
 Petoboun, his x mark.  
 Wecha, his x mark.  
 Swopia, his x mark.  
 Quinch, his x mark.  
 Oveto, his x mark.  
 Yeawer, his x mark, (Capota.)

FORTY-THIRD CONGRESS. SESS. I. CH. 136, 137, 141. 1874.

41

Savonnearoa, his x mark.  
Careta, his x mark.

Parcewich, his x mark.  
Teributoni, his x mark.

Witnesses:

THOMAS A. DOLAN.  
T. D. BURNS.  
M. V. STEVENS.

SEC. 2. That the Secretary of the Treasury shall issue, set apart, and hold, as a perpetual fund, in trust for the Ute Indians, a sufficient amount of five-per-centum bonds of the United States, the interest on which shall be twenty-five thousand dollars per annum; which interest shall be paid annually, as the President of the United States may direct, for the benefit of said Indians. Bonds to be issued and held by Secretary of Treasury in trust. Interest, how paid.

SEC. 3. That the Secretary of the Treasury shall cause to be paid to Ouray one thousand dollars, as the first installment due him annually, so long as he shall be chief of said Ute Indians; and there is hereby appropriated, out of any money in the Treasury not otherwise appropriated, one thousand dollars for that purpose. Payment to Ouray.

Approved, April 29, 1874.

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199

**CHAP. 223.**—An act to accept and ratify the agreement submitted by the confederated bands of Ute Indians in Colorado, for the sale of their reservation in said State, and for other purposes, and to make the necessary appropriations for carrying out the same.

June 15, 1880.

Whereas certain of the chiefs and headmen of the confederated bands of the Ute tribe of Indians, now present in the city of Washington, have agreed upon and submitted to the Secretary of the Interior an agreement for the sale to the United States of their present reservation in the State of Colorado, their settlement upon lands in severalty, and for other purposes; and

Preamble.

Whereas the President of the United States has submitted said agreement, with his approval of the same, to the Congress of the United States for acceptance and ratification, and for the necessary legislation to carry the same into effect: Therefore

*Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,* That said agreement be, and the same is hereby, accepted, ratified, and confirmed: *Provided*, That the said agreement shall be amended by adding to the first clause thereof, after the words "guilty parties", the words following, to wit: "Until such surrender or apprehension, or until the President shall be satisfied that the guilty parties are no longer living or have fled beyond the limits of the United States, the proportion of the money, hereinafter provided, coming to that portion of the Ute Indians known as the White River Utes, except for removal and settlement, shall not be paid"; and by adding to the third express condition of said agreement after the word "forever", the words following, to wit: "*Provided*, That the President of the United States may, in his discretion, appropriate an amount thereof, not exceeding ten thousand dollars, for the education in schools established within or beyond the limits of the lands selected, of such youths of both sexes as in his judgment may be best qualified to make proficiency in practical industries and pursuits necessary for their self-support, and out of the portion of said moneys coming to the White River Utes, the United States shall pay annually to the following-named persons, during the period of twenty years, if they shall live so long, the following sums respectively: To Mrs. Arivella D. Meeker, five hundred dollars; to Miss Josephine Meeker five hundred dollars; to Mrs. Sophronia Price, five hundred dollars; to Mrs. Maggie Gordon, five hundred dollars; to George Dresser, two hundred dollars; to Mrs. Sarah M. Post, five hundred dollars; to Mrs. Eaton, mother of George Eaton, two hundred dollars; to the parents of Arthur L. Thompson two hundred dollars; to the father of Fred Shepard, two hundred dollars; to the parents of Wilmer Eskridge, two hundred dollars"; and by adding to the fifth express condition of said agreement after word "reaffirmed", the words following to wit: "This sum, together with the annuity of fifty thousand dollars hereinbefore provided, may, in the discretion of Congress, at the end of twenty-five years, be capitalized, and the principal sum be paid to said Indians per capita in lieu of said annuities": *And provided also*, That three-fourths of the adult male members of said confederated bands shall

Ute Indians in Colorado.

*Provided*:  
Agreement for sale of lands.  
Amended and ratified.

*Provided*.

Schools.

Payment annually for twenty years to certain persons.

Agreement further amended.

*Provided*.

200

FORTY-SIXTH CONGRESS. SESS. II. CH. 223. 1890. 200

**Proviso.**

agree to and sign said agreement, upon presentation of the same to them, in open council, in the manner hereinafter provided: *Provided further*, That nothing in this act contained, or in the agreement herein set forth, or in the amendments herein proposed to said agreement, shall be so construed as to compel any Uto Indian to remove from any lands that he or she claims in severalty. Said agreement is in words and figures as follows, namely:

**Agreement.**

The chiefs and headmen of the confederate bands of the Utes now present in Washington, hereby promise and agree to procure the surrender, to the United States, for trial and punishment, if found guilty, of those members of their nation, not yet in the custody of the United States, who were implicated in the murder of United States Indian Agent N. C. Meeker and the murder of and outrages upon the employees at the White River Agency on the twenty-ninth day of September, eighteen hundred and seventy-nine, and in case they do not themselves succeed in apprehending the said parties, presumably guilty of the above-mentioned crime, that they will not in any manner obstruct, but faithfully aid, any officers of the United States, directed by the proper authorities, to apprehend such presumably guilty parties.

The said chiefs and headmen of the confederated bands of Utes also agree and promise to use their best endeavors with their people to procure their consent to cede to the United States all the territory of the present Uto Reservation in Colorado, except as hereinafter provided for their settlement.

The Southern Utes agree to remove to and settle upon the unoccupied agricultural lands on the La Plata River, in Colorado; and if there should not be a sufficiency of such lands on the La Plata River and in its vicinity in Colorado, then upon such other unoccupied agricultural lands as may be found on the La Plata River or in its vicinity in New Mexico.

The Uncompahgre Utes agree to remove to and settle upon agricultural lands on Grand River, near the mouth of the Gunnison River, in Colorado, if a sufficient quantity of agricultural land shall be found there, if not then upon such other unoccupied agricultural lands as may be found in that vicinity and in the Territory of Utah.

The White River Utes agree to remove to and settle upon agricultural lands on the Uintah Reservation in Utah.

**Allotment.**

Allotments in severalty of said lands shall be made as follows:

To each head of a family one-quarter of a section, with an additional quantity of grazing land not exceeding one-quarter of a section.

To each single person over eighteen years of age one-eighth of a section, with an additional quantity of grazing land not exceeding one-eighth of a section.

To each orphan child under eighteen years of age one-eighth of a section, with an additional quantity of grazing land not exceeding one-eighth of a section; and to each other person, under eighteen years, now living, or who may be born prior to said allotments, one-eighth of a section, with a like quantity of grazing land.

All allotments to be made with the advice of the commission hereinafter provided, upon the selection of the Indians, heads of families selecting for their minor children, and the agents making the allotment for each orphan child.

The said chiefs and headmen of the confederated bands of Utes further promise that they will not obstruct or in anywise interfere with travel upon any of the highways now open or hereafter to be opened by lawful authority in or upon any of the lands to be set apart for their use by virtue of this agreement.

**Conditions of agreement.**

The said chiefs and headmen of the confederated bands of Utes promise to obtain the consent of their people to the cession of the territory of their reservation as above on the following express conditions:

**First.**

First. That the Government of the United States cause the lands so set apart to be properly surveyed and to be divided among the said

Indians in severalty in the proportion hereinbefore mentioned, and to issue patents in fee simple to them respectively therefor, so soon as the necessary laws are passed by Congress. The title to be acquired by the Indians shall not be subject to alienation, lease, or incumbrance, either by voluntary conveyance of the grantee or by the judgment, order, or decree of any court, or subject to taxation of any character, but shall be and remain inalienable and not subject to taxation for the period of twenty-five years, and until such time thereafter as the President of the United States may see fit to remove the restriction, which shall be incorporated in the patents when issued, and any contract made prior to the removal of such restriction shall be void.

Conditions—Continued.

Second. That so soon as the consent of the several tribes of the Ute Nation shall have been obtained to the provisions of this agreement, the President of the United States shall cause to be distributed among them in cash the sum of sixty thousand dollars of annuities now due and provided for, and so much more as Congress may appropriate for that purpose; and that a commission shall be sent to superintend the removal and settlement of the Utes, and to see that they are well provided with agricultural and pastoral lands sufficient for their future support, and upon such settlement being duly effected, that they are furnished with houses, wagons, agricultural implements, and stock cattle sufficient for their reasonable wants, and also such saw and grist mills as may be necessary to enable them to commence farming operations, and that the money to be appropriated by Congress for that purpose shall be apportioned among the different bands of Utes in the following manner: One-third to those who settle on the La Plata River and vicinity, one-half to those settling on Grand River and vicinity, and one-sixth to those settling on the Uintah Reservation.

Second.

Third. That in consideration of the cession of territory to be made by the said confederated bands of the Ute Nation, the United States, in addition to the annuities and sums for provisions and clothing stipulated and provided for in existing treaties and laws, agrees to set apart and hold, as a perpetual trust for the said Ute Indians, a sum of money, or its equivalent in bonds of the United States, which shall be sufficient to produce the sum of fifty thousand dollars per annum, which sum of fifty thousand dollars shall be distributed per capita to them annually forever.

Third.

Fourth. That as soon as the President of the United States may deem it necessary or expedient, the agencies for the Uncompahgres and Southern Utes be removed to and established at suitable points, to be hereafter selected, upon the lands to be set apart, and to aid in the support of the said Utes until such time as they shall be able to support themselves, and that in the mean time the United States Government will establish and maintain schools in the settlements of the Utes, and make all necessary provision for the education of their children.

Fourth.

Fifth. All provisions of the treaty of March second, eighteen hundred and sixty-eight, and the act of Congress approved April twenty-ninth, eighteen hundred and seventy-four, not altered by this agreement, shall continue in force, and the following words from article three of said act, namely, "The United States agrees to set apart and hold, as a perpetual trust for the Ute Indians, a sum of money or its equivalent in bonds, which shall be sufficient to produce the sum of twenty-five thousand dollars per annum, which sum of twenty-five thousand dollars per annum shall be disbursed or invested at the discretion of the President, or as he may direct, for the use and benefit of the Ute Indians forever", are hereby expressly reaffirmed.

Fifth.  
1868, treaty of  
March 2, Indians.  
1874, ch. 135,  
Stat., 18, 35.  
Reaffirmed.

Sixth. That the commissioners above mentioned shall ascertain what improvements have been made by any member or members of the Ute Nation upon any part of the reservation in Colorado to be ceded to the United States as above, and that payment in cash shall be made to the individuals having made and owning such improvements, upon a fair and liberal valuation of the same by the said commission, taking into consideration the labor bestowed upon the land.

Sixth.

202

202

## FORTY-SIXTH CONGRESS. Sess. II. Ch. 223. 1880.

Date, 1880, Mar. 6. Done at the city of Washington this sixth day of March, anno Domini eighteen hundred and eighty.

Signed

Signatures.

CHAVANAUX <sup>his</sup> X  
 IGNATIO <sup>mark</sup> X  
 ALHANDRA <sup>his</sup> X  
 VERATZITZ <sup>mark</sup> X  
 GALOTA <sup>his</sup> X  
 JOCKNICK <sup>mark</sup> X  
 WASS <sup>his</sup> X  
 SAWAWICK <sup>mark</sup> X  
 OURAY <sup>his</sup> X

Witnesses.

Witnesses:

WILL F. BURNS, Interpreter.  
 W. H. BERRY, Interpreter  
 OTTO MEARS, Interpreter  
 HENRY PAGE, United States Indian Agent, Southern Utes.  
 CHARLES ADAMS, Special Agent.

Commissioners  
 appointed, com-  
 pensation, ex-  
 penses.

Clerk's salary,  
 bond, duties.

To report.

Census of In-  
 dians.

Particulars of  
 census.

SEC. 2. That the President of the United States be, and he is hereby, authorized and empowered to appoint, by and with the advice and consent of the Senate, five commissioners, who shall receive compensation for their services at the rate of ten dollars per diem while actually engaged, in addition to their actual traveling and other necessary expenses; and said commissioners shall, under such instructions as the Secretary of the Interior may give them, present said agreement to the confederated bands of the Ute Indians in open council for ratification, as provided in the first section of this act; and said commissioners shall have a clerk, at a salary of two hundred dollars per month, in addition to his actual traveling and other necessary expenses, and who shall give bond in an amount to be fixed by the Secretary of the Interior, and shall act also as disbursing officer for said commissioners. And upon the ratification of said agreement by said tribe as herein provided, said commissioners shall, under the direction of the Secretary of the Interior, appraise the improvements belonging to said Ute Indians upon the lands surrendered by them as provided in said agreement, and report the same to the Secretary of the Interior for settlement. It shall be their duty to take a careful census of said Indians, separating them under said census as follows:

First. Those known in the agreement above referred to as Southern Utes.

Second. Those known as Uncompahgre Utes.

Third. Those known as White River Utes.

Said census shall also show separately the name of each head of a family, and the number of persons in such family, distinguishing those over eighteen years of age from those under eighteen years of age, and giving the names of each separately; also, said census shall show separately the orphan children in each of said classes of Utes described in the foregoing agreement, and they shall make an accurate register of the names, ages, occupations, and general condition of each of the above classes as aforesaid, specifying particularly the number and names of said Indians incapable by reason of orphanage, minority, or other dis-

ability of managing their own affairs, and they shall also select lands and allot them in severalty to said Indians, as herein provided, and superintend the removal, location, and settlement of the Indians thereon, and do and perform such other services as the Secretary of the Interior may consider necessary for them to do in the execution of the provisions of this act.

Lands allotted in severalty.

And after the said commissioners shall have performed the duties specifically assigned to them by this act, and such other duties as the Secretary of the Interior may require of them, they shall make a full report of their proceedings to the Secretary of the Interior, which shall set forth, among other things, the name of each person to whom they may have apportioned and allotted lands as herein provided for, with the name and condition of such person, showing who, upon proofs, are considered incompetent to take charge of their property, either as orphans, minors, or for other causes; and shall also exhibit the quantity of land assigned to each person, with the metes and bounds of such allotments. And said commissioners shall make an accurate map of the whole survey and proceeding, showing the partition and division aforesaid, a copy of which map shall be filed with said report; and the Secretary of the Interior shall cause a copy to be filed in the General Land Office, and copies shall also be filed in the office of the surveyors-general of Utah, Colorado and New Mexico, and also in the office of the register and receiver of the land district in which such lands or any portion of them may be situate. Said commissioners shall further report the total number of acres allotted and set apart as provided by the foregoing agreement, the amount of such land tillable without irrigation, the amount of irrigation required, and the probable cost thereof. They shall also locate the agencies for the Southern Utes and the Uncompahgre Utes, shall furnish an estimate of the number of houses required, the cost of each, the number of school-houses required and the number of teachers, and the number of children of school age, and such other data as the Secretary of the Interior may require to enable him to make judicious expenditure of the money appropriated in section nine of this act; and said commissioners shall exercise direct supervision and control of all expenditures under this act during the time they remain in the Ute country, under the general direction of the Secretary of the Interior; and they shall render a full and detailed account of such expenditure, with the vouchers therefor, as now provided by law.

Commissioners to make full report.

Map and survey.

Further report of acres allotted.

Agencies located.

Estimate of school-houses and school children.

To supervise and control expenditures and render accounts and vouchers.

SEC. 3. That the Secretary of the Interior be, and he is hereby, authorized to cause to be surveyed, under the direction of said commissioners, a sufficient quantity of land in the vicinities named in said agreement, to secure the settlement in severalty of said Indians as therein provided. And upon the completion of said survey and enumeration herein required, the said commissioners shall cause allotments of lands to be made to each and all of the said Indians, in quantity and character as set forth in the agreement above mentioned, and whenever the report and proceedings of said commissioners, as required by this act, are approved by the President of the United States, he shall cause patents to issue to each and every allottee for the lands so allotted, with the same conditions, restrictions and limitations mentioned therein as are provided in said agreement; and all the lands not so allotted, the title to which is, by the said agreement of the confederated bands of the Ute Indians, and this acceptance by the United States, released and conveyed to the United States, shall be held and deemed to be public lands of the United States and subject to disposal under the laws providing for the disposal of the public lands, at the same price and on the same terms as other lands of like character, except as provided in this act: *Provided*, That none of said lands, whether mineral or otherwise, shall be liable to entry and settlement under the provisions of the homestead law; but shall be subject to cash entry only in accordance with existing law; and when sold the proceeds of said sale shall be first sacredly applied to reimbursing the United States for all sums paid out or set apart under this act by

Settlement in severalty.

Allotment of land in severalty.

Patents issued to allottees.

Lands not allotted, released, and conveyed to United States.

To be held and disposed of as other public lands.

*Provided*.

Proceeds of sales, distribution of.

Remainder deposited in Treasury in trust for Indians.

*Proviso.*

R. S. 1977. Indians subject to provisions of.

*Proviso.*

Perpetual trust-fund, interest \$50,000, paid per capita annually.

Salaries to Utes continued ten years longer than stipulated in treaties.

\$4,000 per annum to be distributed by the President.

R. S., Title 28, extended to lands allotted to Indians.

Hot Springs in Uncompahgre Park and four square miles reserved from sale, &c.

R. S. 2474 and 2475 made applicable thereto.

Appropriations.

Expenses of commissioners.

Removal, &c., Utes.

the government for the benefit of said Indians, and then to be applied in payment for the lands at one dollar and twenty-five cents per acre which may be ceded to them by the United States outside of their reservation, in pursuance of this agreement. And the remainder, if any, shall be deposited in the Treasury as now provided by law for the benefit of the said Indians, in the proportion hereinbefore stated, and the interest thereon shall be distributed annually to them in the same manner as the funds provided for in this act: *Provided further*, That the subdivisions upon which are located improvements to be appraised, as provided for in section two of this act, shall be offered to the highest bidder at public sale, after published notice of at least thirty days by the Secretary of the Interior, and the same shall be absolutely reserved from occupation or claim until so sold.

SEC. 4. That upon the completion of said allotments and the patenting of the lands to said allottees, each and every of the said Indians shall be subject to the provisions of section nineteen hundred and seventy-seven of the Revised Statutes and to the laws, both civil and criminal, of the State or Territory in which they may reside, with the right to sue and be sued in the courts thereof: *Provided*, That their lands and personal property shall not be subject to taxation or execution upon the judgment, order, or decree of any court obtained on any cause of action which may arise during the period named in the above recited agreement.

SEC. 5. That the Secretary of the Treasury shall, out of any moneys in the Treasury not otherwise appropriated, set apart, and hold as a perpetual trust-fund for said Ute Indians, an amount of money sufficient at four per centum to produce annually fifty thousand dollars, which interest shall be paid to them per capita in cash, annually, as provided in said agreement.

SEC. 6. That all salaries paid to any member or members of the Ute tribe under existing treaty stipulations shall be continued for the term of ten years beyond the time fixed in said treaties. And the sum of four thousand dollars per annum for the term of ten years shall be distributed by the President at his discretion to such of said Indians as distinguish themselves by good sense, energy, and perseverance in the pursuits of civilized life, and in the promotion of a good understanding between the Indians and the Government and people of the United States, and there is hereby appropriated, out of any moneys in the Treasury not otherwise appropriated, four thousand dollars as the first installment for such purpose.

SEC. 7. That the provisions of title twenty-eight of the Revised Statutes shall extend over and be applicable to every allotment of land provided for in the foregoing agreement, and to the administration of the affairs of said Indians, so far as said provisions can be made applicable thereto.

SEC. 8. That the hot springs located in what is known as "The Uncompahgre Park", in the Uncompahgre Valley, and four square miles of land surrounding said springs and within said valley, are hereby reserved, and withdrawn from settlement, occupancy, or sale, under the laws of the United States, and dedicated and set apart for the benefit and enjoyment of the people; and, so far as practicable, the provisions of sections twenty-four hundred and seventy-four and twenty-four hundred and seventy-five, of the Revised Statutes, are hereby made applicable to said tract.

SEC. 9. That for the purpose of carrying the provisions of this act into effect, the following sums, or so much thereof as may be necessary, be, and they are hereby, appropriated, out of any moneys in the Treasury not otherwise appropriated, to be expended under the direction of the Secretary of the Interior as follows, namely:

For the payment of the expenses of the commissioners herein provided, the sum of twenty-five thousand dollars.

For the cost of removal and settlement of the Utes, surveying their lands, building houses, establishing schools, building mills and agency

FORTY-SIXTH CONGRESS. Sess. II. Ch. 223, 224. 1880.

205

buildings, purchasing stock, agricultural implements, and so forth, as provided in said agreement and in this act, the sum of three hundred and fifty thousand dollars.

For the sum to be paid to said Ute Indians, per capita, in addition to the sixty thousand dollars now due and provided for, the sum of fifteen thousand dollars. Per capita in addition to Utes.

For the payment of the appraised value of individual improvements as provided herein, the sum of twenty thousand dollars. Individual improvements.

For the care and support of the Ute Indians in Colorado for the balance of the current fiscal year, the sum of twelve thousand dollars: *Provided*, That with the exception of the appropriation for expenses of the commissioners, the above appropriations shall become available only upon the ratification of said agreement by three-fourths of the male adult members of the Ute Indians as provided in this act, and the certification of such fact to the Secretary of the Treasury by the Secretary of the Interior. Support of Utes in Colorado current fiscal year. *Proviso.*

SEC. 10. If the agreement as amended in this act is not ratified by three-fourths of the adult male Indians of the Ute tribes within four months from the approval of this act the same shall cease to be of effect after that day. Time limited for ratification of amended agreement by three-fourths of male adult Utes.

Approved June 15, 1880.

677

**CHAP. 113.**—An Act to disapprove the treaty heretofore made with the Southern Ute Indians to be removed to the Territory of Utah, and providing for settling them down in severalty where they may so elect and are qualified, and to settle all those not electing to take lands in severalty on the west forty miles of present reservation and in portions of New Mexico, and for other purposes, and to carry out the provisions of the treaty with said Indians June fifteenth, eighteen hundred and eighty

February 20, 1893.

*Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,* That the agreement made by J. Montgomery Smith, Thomas S. Childs, and R. B. Weaver, commissioners on the part of the United States, with the Southern Ute Indians of Colorado, bearing date November thirteenth, eighteen hundred and eighty-eight, be, and the same is hereby, annulled, and the treaty made with said Indians June fifteenth, eighteen hundred and eighty, be carried out as herein provided, and as further provided by general law for settling Indians in severalty.

Southern Ute In-  
dians, Colo.  
Lands in severalty  
to, etc.

Vol. 25, p. 133.

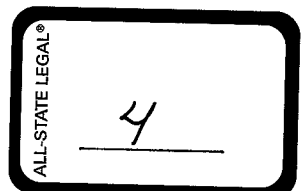
Vol. 21, p. 199.

**SEC. 2.** That within six months after the passage of this Act the Secretary of the Interior shall cause allotment of land, in severalty, to be made to such of the Southern Ute Indians in Colorado as may elect and be considered by him qualified to take the same out of the agricultural lands embraced in their present reservation in Colorado, such allotments to be made in accordance with the provisions of the Act of Congress approved June fifteenth, eighteen hundred and eighty, entitled "An Act to accept and ratify the agreement submitted by the confederated bands of Ute Indians in Colorado for the sale of their reservation in said State, and for other purposes, and to make the necessary

Allotment to In-  
dians.

Post, p. 891.

Vol. 21, p. 199.



678

678

## FIFTY-THIRD CONGRESS. SESS. III. CH. 113. 1895.

*Proviso.*  
Tribal rights.

Reservation for In-  
dians not taking allot-  
ments.

Agency.

Surplus lands open  
to settlement.

*Provisos.*  
Appraisal, etc., of  
improvements.

Maximum.  
Proceeds.

Disposal of receipts  
from sales.

Per capita.

Sheep.

Chiefs.

Balance to be held  
in trust.

appropriations for carrying out the same," and the amendments thereto, as far as applicable hereto, and the treaties heretofore made with said Indians: *Provided*, That Indians taking allotments as herein provided shall retain their interest in all tribal property.

SEC. 3. That for the sole and exclusive use and occupancy of such of said Indians as may not elect or be deemed qualified to take allotments of land in severalty, as provided in the preceding section, there shall be, and is hereby, set apart and reserved all that portion of their present reservation lying west of the range line between ranges thirteen and fourteen west of the New Mexico principal meridian, and also all of townships thirty-one and thirty-two of ranges fourteen, fifteen, and sixteen west of the New Mexico principal meridian and lying in the Territory of New Mexico, subject, however, to the right of the Government to erect and maintain agency buildings thereon and to grant rights of way through the same for railroads, irrigation ditches, highways, and other necessary purposes; and the Government shall maintain an agency at some suitable place on said lands so reserved.

SEC. 4. That at the expiration of six months from the passage of this Act the President of the United States shall issue his proclamation declaring the lands embraced within the present reservation of said Indians except such portions as may have been allotted or reserved under the provisions of the preceding sections of this Act, open to occupancy and settlement, and thereupon said lands shall be and become a part of the public domain of the United States, and shall be subject to entry under the desert, homestead, and town-site laws and the laws governing the disposal of coal, mineral, stone, and timber lands: but no homestead settler shall receive a title to any portion of such lands at less than one dollar and twenty-five cents per acre, and shall be required to make a cash payment of fifty cents per acre at the time filing is made upon any of said lands: *Provided*, That before said lands shall be open to public settlement the Secretary of the Interior shall cause the improvements belonging to the Indians on the lands now occupied by them to be appraised and sold at public sale to the highest bidder, except improvements on lands allotted to the Indians in accordance with the provisions of this Act. No sale of such improvements shall be made for less than the appraised value, and the several purchasers of said improvements shall, for thirty days after the issuance of the President's proclamation, have the preference right of entry of the lands upon which the improvements purchased by him are situated: *Provided further*, That the said purchase shall not exceed one hundred and sixty acres: *And provided further*, That the proceeds of the sale of such improvements shall be paid to the Indians owning the same.

SEC. 5. That out of the moneys first realized from the sale of said lands so opened up to public settlement there shall be paid to said Indians the sum of fifty thousand dollars, as follows: Five thousand dollars annually for ten years, and, when paid, the money to be equally divided among all of said Indians per capita, irrespective of age or sex; also the sum of twenty thousand dollars of said proceeds shall be paid to the Secretary of the Interior, who shall invest the same in sheep and divide the said sheep among the said Indians per capita equally, irrespective of age or sex; also to Ignacio, head chief; to Buckskin Charlie, as chief of the Moaches, and Mariano, as chief of the Weeminches, the sum of five hundred dollars each; also to Tapucke and Tabewatch, as chiefs of the Capotes, the sum of two hundred and fifty dollars each; that the balance of the money realized from the sale of lands, after deducting expenses of sale and survey, shall be held in the Treasury of the United States in trust for the sole use and benefit of said Southern Ute Indians. That nothing herein provided shall in any manner be construed to change or interfere with the rights of said Indians under any other existing treaty regarding any annuities or trust funds or the interest thereon.

## SEVENTIETH CONGRESS. SESS. I. CHS. 516, 517. 1928.

495

**CHAP. 516.**—An Act To provide for the times and places for holding court for the Eastern District of North Carolina.

May 10, 1928.  
[S. 3947.]  
[Public, No. 359.]

*Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,* That the terms of the District Court for the Eastern District of North Carolina shall be held at Durham on the first Monday in March and September; at Raleigh a one-week civil term on the second Monday in March and September, and a criminal term only on the second Monday after the fourth Monday in April and October; at Fayetteville on the third Monday in March and September; at Elizabeth City on the fourth Monday in March and September; at Washington on the first Monday in April and October; at New Bern on the second Monday in April and October; at Wilson on the third Monday in April and October, and at Wilmington a two-weeks term on the fourth Monday in April and October: *Provided*, That this Act shall take effect on July 1, 1928: *And provided further*, That at Wilson and Durham it shall be made incumbent upon each place to provide suitable facilities for holding the courts.

North Carolina eastern judicial district.  
Terms of court for.  
Vol. 43, p. 661, amended.

*Provisos.*  
Effective July 1, 1928.  
Court rooms required at Wilson and Durham.

Approved, May 10, 1928.

**CHAP. 517.**—An Act To extend the period of restriction in lands of certain members of the Five Civilized Tribes, and for other purposes.

May 10, 1928.  
[S. 3594.]  
[Public, No. 360.]

*Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,* That the restrictions against the alienation, lease, mortgage, or other encumbrance of the lands allotted to members of the Five Civilized Tribes in Oklahoma, enrolled as of one-half or more Indian blood, be, and they are hereby, extended for an additional period of twenty-five years commencing on April 26, 1931: *Provided*, That the Secretary of the Interior shall have the authority to remove the restrictions, upon the applications of the Indian owners of the land, and may remove such restrictions, wholly or in part, under such rules and regulations concerning terms of sale and disposal of the proceeds for the benefit of the respective Indians as he may prescribe.

Five Civilized Tribes, Okla.  
Restriction on allotments to members of one-half or more Indian blood further extended.

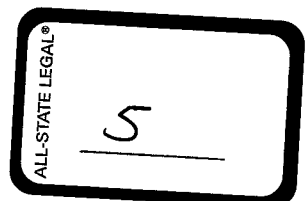
*Proviso.*  
Removal authorized upon application of owners of land.

Sec. 2. That the provisions of section 9 of the Act of May 27, 1908 (Thirty-fifth Statutes at Large, page 312), entitled "An Act for the removal of restrictions from part of the lands of allottees of the Five Civilized Tribes, and for other purposes," as amended by section 1 of the Act of April 12, 1926 (Forty-fourth Statutes at Large, page 239), entitled "An Act to amend section 9 of the Act of May 27, 1908 (Thirty-fifth Statutes at Large, page 312), and for putting in force, in reference to suits involving Indian titles, the statutes of limitations of the State of Oklahoma, and providing for the United States to join in certain actions, and for making judgments binding on all parties, and for other purposes," be, and are hereby, extended and continued in force for a period of twenty-five years from and including April 26, 1931, except, however, the provisions thereof which read as follows:

Provisions for removing restrictions on death of allottees continued 25 years from April 26, 1931.  
Vol. 44, p. 239.

*"Provided further*, That if any member of the Five Civilized Tribes of one-half or more Indian blood shall die leaving issue surviving, born since March 4, 1906, the homestead of such deceased allottee shall remain inalienable, unless restrictions against alienation are removed therefrom by the Secretary of the Interior for the use and support of such issue, during their life or lives, until April 26, 1931; but if no such issue survive, then such allottee, if an adult, may dispose of his homestead by will free from restrictions; if this be not done, or in the event the issue hereinabove provided for die before April 26, 1931, the lands shall then descend to the

Provision for homesteads of decedent allottees repealed.  
Vol. 44, p. 239, repealed.



heirs, according to the laws of descent and distribution of the State of Oklahoma, free from all restrictions: *Provided*, That the word "issue," as used in this section, shall be construed to mean child or children: *Provided further*, That the provisions of section 23 of the Act of April 26, 1906, as amended by this Act, are hereby made applicable to all wills executed under this section:"

Effective, April 26, 1931.  
*Proviso.*  
 Provisions for disposal of property by wills continued until April 26, 1956.  
 Vol. 34, p. 145, Vol. 35, p. 315.  
 Vol. 44, p. 240.

which quoted provisions be, and the same are, repealed, effective April 26, 1931: *Provided further*, That the provisions of section 23 of the Act of Congress approved April 26, 1906 (Thirty-fourth Statutes at Large, page 137), as amended by the provisions of section 8 of the Act of Congress approved May 27, 1908 (Thirty-fifth Statutes at Large, page 312), be, and the same are hereby, continued in force and effect until April 26, 1956.

Minerals produced from restricted lands subject to taxation after April 26, 1931.

SEC. 3. That all minerals, including oil and gas, produced on or after April 26, 1931, from restricted allotted lands of members of the Five Civilized Tribes in Oklahoma, or from inherited restricted lands of full-blood Indian heirs or devisees of such lands, shall be subject to all State and Federal taxes of every kind and character the same as those produced from lands owned by other citizens of the State of Oklahoma; and the Secretary of the Interior is hereby authorized and directed to cause to be paid, from the individual Indian funds held under his supervision and control and belonging to the Indian owners of the lands, the tax or taxes so assessed against the royalty interest of the respective Indian owners in such oil, gas, and other mineral production.

Payment from funds of individual Indian owners.

Restricted lands in excess of 160 acres subject to State taxation after April 26, 1931.

SEC. 4. That on and after April 26, 1931, the allotted, inherited, and devised restricted lands of each Indian of the Five Civilized Tribes in excess of one hundred and sixty acres shall be subject to taxation by the State of Oklahoma under and in accordance with the laws of that State, and in all respects as unrestricted and other lands: *Provided*, That the Indian owner of restricted land, if an adult and not legally incompetent, shall select from his restricted land a tract or tracts, not exceeding in the aggregate one hundred and sixty acres, to remain exempt from taxation and shall file with the superintendent for the Five Civilized Tribes a certificate designating and describing the tract or tracts so selected: *And provided further*, That in cases where such Indian fails, within two years from date hereof, to file such certificate, and in cases where the Indian owner is a minor or otherwise legally incompetent, the selection shall be made and certificate prepared by the superintendent for the Five Civilized Tribes; and such certificate, whether by the Indian or by the superintendent for the Five Civilized Tribes, shall be subject to approval by the Secretary of the Interior and, when approved by the Secretary of the Interior, shall be recorded in the office of the superintendent for the Five Civilized Tribes and in the county records of the county in which the land is situated; and said lands, designated and described in the approved certificates so recorded, shall remain exempt from taxation while the title remains in the Indian designated in such approved and recorded certificate, or in any full-blood Indian heir of devisee of the land: *Provided*, That the tax exemption shall not extend beyond the period of restrictions provided for in this Act: *And provided further*, That the tax-exempt land of any such Indian allottee, heir, or devisee shall not at any time exceed one hundred and sixty acres.

*Proviso.*  
 Selection to be made by owner of exempted tracts.

Selection by superintendent on failure of Indian, etc.

Designated lands exempt from taxation.

Exemption period limited.

Not over 160 acres exempt.

No restrictions reimposed nor taxation exempted hereby.

SEC. 5. That this Act shall not be construed to reimpose restrictions heretofore or hereafter removed by the Secretary of the Interior or by operation of law, nor to exempt from taxation any lands which are subject to taxation under existing law.

Approved, May 10, 1928.

## SEVENTIETH CONGRESS. SESS. I. CHS. 518-521. 1928.

497

**CHAP. 518.**—An Act Donating Revolutionary cannon to the New York State Conservation Department.

May 11, 1928.  
[S. 805.]  
[Public, No. 361.]

*Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,* That the Secretary of War, in his discretion, is hereby authorized to deliver to the order of the New York State Conservation Department five Revolutionary cannon stored in the Watervliet Arsenal at Watervliet, New York, and marked "W. A. 60," "W. A. 61," "W. A. 62," "W. A. 63," and "W. A. 64": *Provided*, That the United States shall be put to no expense in connection with the delivery of said cannon.

Army.  
Revolutionary cannon donated to New York Conservation Department.

*Proviso.*  
No Government expense.

Approved, May 11, 1928.

**CHAP. 519.**—An Act Authorizing a per capita payment to the Rosebud Sioux Indians, South Dakota.

May 11, 1928.  
[S. 3438.]  
[Public, No. 362.]

*Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,* That the Secretary of the Interior be, and he is hereby, authorized to withdraw from the Treasury of the United States so much of the tribal funds on deposit therein to the credit of the Rosebud Indians, of South Dakota, as may be required to make a \$10 per capita payment to the recognized members of the tribe, and to pay or distribute the same under such rules and regulations as he may prescribe.

Rosebud Sioux Indians, S. Dak.  
Per capita payment to, from tribal funds.

Approved, May 11, 1928.

**CHAP. 520.**—An Act To authorize the Secretary of War to donate to the city of Charleston, South Carolina, a certain bronze cannon.

May 11, 1928.  
[H. R. 6492.]  
[Public, No. 363.]

*Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,* That the Secretary of War is authorized and directed to donate, without expense to the United States, to the city of Charleston, South Carolina, a smooth bore, muzzle loading, bronze field gun, numbered 124, captured from the Confederate forces, and now in the Watervliet Arsenal, Watervliet, New York.

Army.  
Cannon taken from Confederate forces, donated to Charleston, S. C.

Approved, May 11, 1928.

**CHAP. 521.**—An Act To abolish the office of administrative assistant and disbursing officer in the Library of Congress and to reassign the duties thereof.

May 11, 1928.  
[H. R. 10544.]  
[Public, No. 364.]

*Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,* From and after June 10, 1928, the office of administrative assistant and disbursing officer of the Library of Congress, created by Act of Congress approved June 29, 1922, is abolished and thereafter the duties required to be performed by the administrative assistant and disbursing officer shall be performed, under the direction of the Librarian of Congress, by such persons as the Librarian may appoint for those purposes: *Provided*, That the person who shall disburse the appropriations for the Library of Congress and the Botanic Garden shall give bond payable to the United States in the sum of \$30,000, with sureties approved by the Secretary of the Treasury for the faithful discharge of his duties.

Library of Congress.  
Office of administrative assistant, etc., abolished.  
Vol. 42, p. 715.

Post, p. 529.  
Duties conferred upon Librarian.

*Proviso.*  
Bond for disbursements.

Approved, May 11, 1928.



LEXSTAT 25 U.S.C. 396A

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\*\*\* CURRENT THROUGH PL 111-138, APPROVED 2/1/2010, WITH A GAP OF P.L. 111-127 \*\*\*

TITLE 25. INDIANS  
CHAPTER 12. LEASE, SALE, OR SURRENDER OF ALLOTTED OR UNALLOTTED LANDS

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25 USCS § 396a

§ 396a. Leases of unallotted lands for mining purposes; duration of leases

Hereafter [on and after May 11, 1938] unallotted lands within any Indian reservation or lands owned by any tribe, group, or band of Indians under Federal jurisdiction, except those hereinafter specifically excepted from the provisions of this Act [25 USCS §§ 396a et seq.], may, with the approval of the Secretary of the Interior, be leased for mining purposes, by authority of the tribal council or other authorized spokesmen for such Indians, for terms not to exceed ten years and as long thereafter as minerals are produced in paying quantities.

**HISTORY:**

(May 11, 1938, ch 198, § 1, 52 Stat. 347.)

**HISTORY; ANCILLARY LAWS AND DIRECTIVES**

Other provisions:

**Repeal of inconsistent Acts.** Act May 11, 1938, ch 198, § 7, 52 Stat. 348, provided: "All Act [Acts] or parts of Acts inconsistent herewith are hereby repealed."

**NOTES:**

Code of Federal Regulations:

Bureau of Indian Affairs, Department of the Interior--Leasing of tribal lands for mineral development, 25 CFR 211.1 et seq.

Bureau of Indian Affairs, Department of the Interior--Surface exploration, mining, and reclamation of lands, 25 CFR 216.1 et seq.

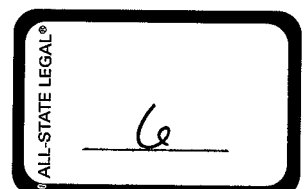
Bureau of Indian Affairs, Department of the Interior--Management of tribal assets of Ute Indian Tribe, Uintah and Ouray Reservation, Utah, by the Tribe and the Ute Distribution Corp, 25 CFR 217.1 et seq.

Bureau of Indian Affairs, Department of the Interior--Oil and gas, geothermal, and solid minerals agreements, 25 CFR 225.1 et seq.

Minerals Management Service, Department of the Interior--General, 30 CFR 201.100 et seq.

Minerals Management Service, Department of the Interior--Royalties, 30 CFR 202.51 et seq.

Minerals Management Service, Department of the Interior--Relief or reduction in royalty rates, 30 CFR 203.0 et seq.



25 USCS § 396a

Minerals Management Service, Department of the Interior--Product valuation, *30 CFR 206.10* et seq.

Minerals Management Service, Department of the Interior--Sales agreements or contracts governing the disposal of lease products, *30 CFR 207.1* et seq.

Minerals Management Service, Department of the Interior--Collection of royalties, rentals, bonuses and other monies due the Federal Government, *30 CFR 218.10* et seq.

Minerals Management Service, Department of the Interior--Penalties, *30 CFR 241.50* et seq.

Minerals Management Service, Department of the Interior--Suspensions pending appeal and bonding-royalty management program, *30 CFR 243.1* et seq.

Related Statutes & Rules:

Wind River Indian Reservation, administration and leasing of minerals, *25 USCS § 611* note.

This section is referred to in *25 USCS §§ 396f, 396g*.

Research Guide:

Federal Procedure:

16 Moore's Federal Practice (Matthew Bender 3d ed.), ch 105, Other Subject Matter Jurisdiction Statutes § 105.25.

Am Jur:

*41 Am Jur 2d, Indians; Native Americans § 71.*

Forms:

12B Am Jur Legal Forms 2d (Rev ed), Mines and Minerals § 175:199.

Annotations:

Application of Indian Mineral Leasing Act (IMLA) and Its Implementing Regulations. *196 ALR Fed 619*.

Texts:

Cohen's Handbook of Federal Indian Law (Matthew Bender), ch 1, History and Background of Federal Indian Policy § 1.05.

Cohen's Handbook of Federal Indian Law (Matthew Bender), ch 4, Indian Tribal Governments §§ 4.04, 4.07.

Cohen's Handbook of Federal Indian Law (Matthew Bender), ch 8, Taxation § 8.04.

Cohen's Handbook of Federal Indian Law (Matthew Bender), ch 17, Natural Resources § 17.03.

1 Energy Law & Transactions (Matthew Bender), ch 21, Leasing on Federal Lands: Onshore § 21.02.

2A Environmental Law Practice Guide (Matthew Bender), ch 15A, Indian Country Environmental Law § 15A.01.

Law Review Articles:

Royster. Practical Sovereignty, Political Sovereignty, and the Indian Tribal Energy Development and Self-Determination Act. *12 Lewis & Clark L Rev 1065*, Winter 2008.

## 25 USCS § 396a

LeBeau. Reclaiming Reservation Infrastructure: Regulatory and Economic Opportunities for Tribal Development. 12 *Stan L & Pol'y Rev* 237, Spring 2001.

EagleWoman; WasteWin. Tribal Nation Economics: Rebuilding Commercial Prosperity in Spite of U.S. Trade Re-straints--Recommendations for Economic Revitalization in Indian Country. 44 *Tulsa L Rev* 383, Winter 2008.

Ansson. The Navajo Nation's Aneth Extension and the Utah Navajo Trust Fund: Who Should Govern the Fund after Years of Misuse? 14 *TM Cooley L Rev* 555, 1997.

## Interpretive Notes and Decisions:

## 1. Generally 2. Construction 3. Jurisdiction 4. Evidence

**1. Generally**

Indian Mineral Leasing Act of 1938, 25 USCS §§ 396a et seq., is aimed to foster tribal self-determination by giving Indians greater say in use and disposition of resources found on *Indian lands*. *United States v Navajo Nation* (2003) 537 US 488, 155 L Ed 2d 60, 123 S Ct 1079, 2003 CDOS 1897, 16 FLW Fed S 99, on remand, remanded (2003, CA FC) 347 F3d 1327, reh den, reh, en banc, den (2004, CA FC) 2004 US App LEXIS 6041 and reh den, reh, en banc, den (2004, CA FC) 2004 US App LEXIS 6042.

BIA's production requirement in extended term of lease is not invalid rule; rather, leases expire upon cessation of production by operation of statute. *Benson-Montin-Greer Drilling Corp. v Acting Albuquerque Area Director, BIA* (1991) 98 ID 419.

**2. Construction**

25 USCS § 396a does not pre-empt tribe's power to levy privilege tax on occupation of severing oil and gas from reservation land even though tax falls on nonmembers of tribe. *Merrion v Jicarilla Apache Tribe* (1982) 455 US 130, 71 L Ed 2d 21, 102 S Ct 894, 72 OGR 617.

State cannot tax Indian royalty income from oil and gas leases issued to nonIndian lessees pursuant to Indian Mineral Leasing Act of 1938 (25 USCS §§ 396a et seq.); provision of 25 USCS § 398 authorizing states to tax royalty interest of Indian tribes is not incorporated in 1938 Act. *Montana v Blackfeet Tribe of Indians* (1985) 471 US 759, 85 L Ed 2d 753, 105 S Ct 2399, 84 OGR 630 (criticized in *Navajo Nation v HHS* (2002, CA9 Ariz) 285 F3d 864, 2002 CDOS 3021, 2002 Daily Journal DAR 3682).

Indian Mineral Leasing Act of 1938, 25 USCS §§ 396a et seq., and its regulations imposed no fiduciary responsibilities supporting claim for damages against defendant United States regarding Secretary of Interior's approval of coal lease between plaintiff Indian tribe and lessee. *United States v Navajo Nation* (2003) 537 US 488, 155 L Ed 2d 60, 123 S Ct 1079, 2003 CDOS 1897, 16 FLW Fed S 99, on remand, remanded (2003, CA FC) 347 F3d 1327, reh den, reh, en banc, den (2004, CA FC) 2004 US App LEXIS 6041 and reh den, reh, en banc, den (2004, CA FC) 2004 US App LEXIS 6042.

25 USCS § 396a was not intended to exclude equitable application of tolling doctrine. *Jicarilla Apache Tribe v Andrus* (1982, CA10 NM) 687 F2d 1324, 13 ELR 20445, 75 OGR 286.

Indian Tribes' argument that Government mismanaged its sand and gravel assets was not valid claim for relief given that Government did not have fiduciary or statutory duty to maximize prices obtained under leases entered into between tribes and third parties; as such, language in Department of Interior and Related Agencies Appropriations Act, Pub. L. No. 108-7, "losses to or mismanagement of trust funds" could not be used to delay accrual of cause of action for failure to obtain maximum price of mineral assets since such action was not within contemplated scope of Indian Mineral Leasing Act of 1938, 25 USCS §§ 396 et seq.; even if claim for breach of fiduciary duty to obtain maximum return from mineral assets had been available, plain language of Act excluded such claim. *Shoshone Indian Tribe v United States* (2004, CA FC) 364 F3d 1339, reh den (2004, CA FC) 2004 US App LEXIS 19461 and reh, en banc, den (2004, CA FC) 2004 US App LEXIS 19463 and cert den (2005) 544 US 973, 125 S Ct 1824, 161 L Ed 2d 723 and cert den (2005) 544 US 973, 125 S Ct 1826, 161 L Ed 2d 723.

**3. Jurisdiction**

## 25 USCS § 396a

Non-Indian oil company does not have remedy under Indian Mineral Leasing Act of 1938 (25 USCS §§ 396a et seq.) so as to give rise to federal question jurisdiction, where plaintiff is only trying to protect its rights under oil and gas leases with Tribe, by enjoining defendants, who have nothing to do with leases, from tortiously interfering with company's rights under lease. *Superior Oil Co. v Merritt* (1985, DC Utah) 619 F Supp 526, 87 OGR 409.

Court of Federal Claims had jurisdiction over two Native American tribes' claims that United States had breached its trust responsibilities for tribes' sand and gravel resources under Indian Mineral Leasing Act of 1938, 25 USCS §§ 396a et seq., where legislative history showed that statute was intended to cover and did cover sand and gravel upon its enactment and Congress had not excluded sand and gravel permits from control or supervision over Indian mineral resources mandated throughout 25 C.F.R. pt. 211. *Shoshone Indian Tribe of the Wind River Reservation v United States* (2002) 52 Fed Cl 614.

#### 4. Evidence

Where purchaser of mining leases covering lands belonging to Indians sued surety on bond securing performance of contract of sale which contract provided for return of consideration if approval of sale by the Secretary of Interior was not obtained, question of right of plaintiff vendee to recover advance payment was for the jury where defense raised issue that plaintiff's own acts justified defendants' refusal to make refund; interdepartmental communications containing corroborative evidence of willingness of department to approve the sale if cooperation of owners could be assured and admissions by purchaser's officers as to their lack of interest were properly admitted. *Vanadium Corp. v Fidelity & Deposit Co.* (1947, CA2 NY) 159 F2d 105.



LEXSTAT 25 U.S.C. 396A

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TITLE 25. INDIANS  
CHAPTER 12. LEASE, SALE, OR SURRENDER OF ALLOTTED OR UNALLOTTED LANDS

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*25 USCS § 396b*

**§ 396b. Public auction of oil and gas leases; requirements**

Leases for oil- and/or gas-mining purposes covering such unallotted lands shall be offered for sale to the highest responsible qualified bidder, at public auction or on sealed bids, after notice and advertisement, upon such terms and subject to such conditions as the Secretary of the Interior may prescribe. Such advertisement shall reserve to the Secretary of the Interior the right to reject all bids whenever in his judgment the interest of the Indians will be served by so doing, and if no satisfactory bid is received, or the accepted bidder fails to complete the lease, or the Secretary of the Interior shall determine that it is unwise in the interest of the Indians to accept the highest bid, said Secretary may readvertise such lease for sale, or with the consent of the tribal council or other governing tribal authorities, a lease may be made by private negotiations: *Provided*, That the foregoing provisions shall in no manner restrict the right of tribes organized and incorporated under sections 16 and 17 of the Act of June 18, 1934 (48 Stat. 984) [25 USCS §§ 476 and 477], to lease lands for mining purposes as therein provided and in accordance with the provisions of any constitution and charter adopted by any Indian tribe pursuant to the Act of June 18, 1934.

**HISTORY:**

(May 11, 1938, ch 198, § 2, 52 Stat. 347.)

**HISTORY; ANCILLARY LAWS AND DIRECTIVES**

**References in text:**

The "Act of June 18, 1934", referred to in this section, is Act June 18, 1934, ch 576, 48 Stat. 984, popularly known as the Indian Reorganization Act, which appears generally as 25 USCS §§ 461 et seq. For full classification of this Act, consult USCS Tables volumes.

**Other provisions:**

**Repeal of inconsistent Acts.** Act May 11, 1938, ch 198, § 7, 52 Stat. 348, provided: "All Act [Acts] or parts of Acts inconsistent herewith are hereby repealed."

**NOTES:**

25 USCS § 396b

Code of Federal Regulations:

Bureau of Indian Affairs, Department of the Interior--Leasing of tribal lands for mineral development, *25 CFR 211.1* et seq.

Bureau of Indian Affairs, Department of the Interior--Leasing of allotted lands for mineral development, *25 CFR 212.1* et seq.

Bureau of Indian Affairs, Department of the Interior--Surface exploration, mining, and reclamation of lands, *25 CFR 216.1* et seq.

Bureau of Indian Affairs, Department of the Interior--Management of tribal assets of Ute Indian Tribe, Uintah and Ouray Reservation, Utah, by the Tribe and the Ute Distribution Corp, *25 CFR 217.1* et seq.

Bureau of Indian Affairs, Department of the Interior--Oil and gas, geothermal, and solid minerals agreements, *25 CFR 225.1* et seq.

Minerals Management Service, Department of the Interior--General, *30 CFR 201.100* et seq.

Minerals Management Service, Department of the Interior--Royalties, *30 CFR 202.51* et seq.

Minerals Management Service, Department of the Interior--Relief or reduction in royalty rates, *30 CFR 203.0* et seq.

Minerals Management Service, Department of the Interior--Penalties, *30 CFR 241.50* et seq.

Related Statutes & Rules:

This section is referred to in *25 USCS § 396f*.

Research Guide:

Federal Procedure:

19 Fed Proc L Ed, Indians and Indian Affairs § 46:179.

Am Jur:

*41 Am Jur 2d, Indians; Native Americans § 72.*

Annotations:

Application of Indian Mineral Leasing Act (IMLA) and Its Implementing Regulations. *196 ALR Fed 619.*

Texts:

Cohen's Handbook of Federal Indian Law (Matthew Bender), ch 17, Natural Resources § 17.03.

Law Review Articles:

Royster. Sustainability, Culture, and Business: Practical Sovereignty, Political Sovereignty, and the Indian Tribal Energy Development and Self-Determination Act. *12 Lewis & Clark L Rev 1065*, Winter 2008.

LeBeau. Reclaiming Reservation Infrastructure: Regulatory and Economic Opportunities for Tribal Development. *12 Stan L & Pol'y Rev 237*, Spring 2001.

Interpretive Notes and Decisions:

25 USCS § 396b

*25 USCS § 396b* requires advertisement for competitive bids prior to leasing of unallotted tribal lands for oil and gas development where leasing tribe is not organized under Indian Reorganization Act of 1934 (*25 USCS §§ 464 et seq.*). *Navajo Resources, Inc. (1982) 89 ID 412.*



LEXSTAT 25 U.S.C. 396A

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\*\*\* CURRENT THROUGH PL 111-138, APPROVED 2/1/2010, WITH A GAP OF P.L. 111-127 \*\*\*

TITLE 25. INDIANS  
CHAPTER 12. LEASE, SALE, OR SURRENDER OF ALLOTTED OR UNALLOTTED LANDS

Go to the United States Code Service Archive Directory

25 USCS § 396c

§ 396c. Lessees of restricted lands to furnish bonds for performance

Hereafter [on and after May 11, 1938] lessees of restricted Indian lands, tribal or allotted, for mining purposes, including oil and gas, shall furnish corporate surety bonds, in amounts satisfactory to the Secretary of the Interior, guaranteeing compliance with the terms of their leases: *Provided*, That personal surety bonds may be accepted where the sureties deposit as collateral with the said Secretary of the Interior any public-debt obligations of the United States guaranteed as to principal and interest by the United States equal to the full amount of such bonds, or other collateral satisfactory to the Secretary of the Interior, or show ownership to unencumbered real estate of a value equal to twice the amount of the bonds.

**HISTORY:**

(May 11, 1938, ch 198, § 3, 52 Stat. 348.)

**HISTORY; ANCILLARY LAWS AND DIRECTIVES**

Other provisions:

**Repeal of inconsistent Acts.** Act May 11, 1938, ch 198, § 7, 52 Stat. 348, provided: "All Act [Acts] or parts of Acts inconsistent herewith are hereby repealed."

**NOTES:**

Code of Federal Regulations:

Bureau of Indian Affairs, Department of the Interior--Leasing of tribal lands for mineral development, *25 CFR 211.1* et seq.

Bureau of Indian Affairs, Department of the Interior--Leasing of allotted lands for mineral development, *25 CFR 212.1* et seq.

Bureau of Indian Affairs, Department of the Interior--Surface exploration, mining, and reclamation of lands, *25 CFR 216.1* et seq.

Bureau of Indian Affairs, Department of the Interior--Management of tribal assets of Ute Indian Tribe, Uintah and Ouray Reservation, Utah, by the Tribe and the Ute Distribution Corp, *25 CFR 217.1* et seq.

25 USCS § 396c

Bureau of Indian Affairs, Department of the Interior--Oil and gas, geothermal, and solid minerals agreements, *25 CFR 225.1* et seq.

Minerals Management Service, Department of the Interior--General, *30 CFR 201.100* et seq.

Minerals Management Service, Department of the Interior--Royalties, *30 CFR 202.51* et seq.

Minerals Management Service, Department of the Interior--Relief or reduction in royalty rates, *30 CFR 203.0* et seq.

Minerals Management Service, Department of the Interior--Penalties, *30 CFR 241.50* et seq.

Related Statutes & Rules:

This section is referred to in *25 USCS § 396f*.

Research Guide:

Federal Procedure:

19 Fed Proc L Ed, Indians and Indian Affairs § 46:189.

Texts:

Cohen's Handbook of Federal Indian Law (Matthew Bender), ch 17, Natural Resources § 17.03.

Law Review Articles:

Ansson. The Navajo Nation's Aneth Extension and the Utah Navajo Trust Fund: Who Should Govern the Fund after Years of Misuse? *14 TM Cooley L Rev* 555, 1997.



LEXSTAT 25 U.S.C. 396A

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\*\*\* CURRENT THROUGH PL 111-138, APPROVED 2/1/2010, WITH A GAP OF P.L. 111-127 \*\*\*

TITLE 25. INDIANS  
CHAPTER 12. LEASE, SALE, OR SURRENDER OF ALLOTTED OR UNALLOTTED LANDS

**Go to the United States Code Service Archive Directory**

*25 USCS § 396d*

§ 396d. Rules and regulations governing operations; limitations on oil and gas leases

All operations under any oil, gas, or other mineral lease issued pursuant to the terms of this or any other Act affecting restricted Indian lands shall be subject to the rules and regulations promulgated by the Secretary of the Interior. In the discretion of the said Secretary, any lease for oil or gas issued under the provisions of this Act shall be made subject to the terms of any reasonable cooperative unit or other plan approved or prescribed by said Secretary prior or subsequent to the issuance of any such lease which involves the development or production of oil or gas from land covered by such lease.

**HISTORY:**

(May 11, 1938, ch 198, § 4, 52 Stat. 348.)

**HISTORY; ANCILLARY LAWS AND DIRECTIVES**

References in text:

"This Act", referred to in this section, is Act May 11, 1938, ch 198, 52 Stat. 347, which appears as *25 USCS §§ 396a et seq.*

Other provisions:

**Repeal of inconsistent Acts.** Act May 11, 1938, ch 198, § 7, 52 Stat. 348, provided: "All Act [Acts] or parts of Acts inconsistent herewith are hereby repealed."

**NOTES:**

Code of Federal Regulations:

Bureau of Indian Affairs, Department of the Interior--Leasing of tribal lands for mineral development, *25 CFR 211.1 et seq.*

Bureau of Indian Affairs, Department of the Interior--Leasing of allotted lands for mineral development, *25 CFR 212.1 et seq.*

25 USCS § 396d

Bureau of Indian Affairs, Department of the Interior--Leasing of restricted lands of members of Five Civilized Tribes, Oklahoma, for mining, *25 CFR 213.1* et seq.

Bureau of Indian Affairs, Department of the Interior--Surface exploration, mining, and reclamation of lands, *25 CFR 216.1* et seq.

Bureau of Indian Affairs, Department of the Interior--Management of tribal assets of Ute Indian Tribe, Uintah and Ouray Reservation, Utah, by the Tribe and the Ute Distribution Corp, *25 CFR 217.1* et seq.

Bureau of Indian Affairs, Department of the Interior--Oil and gas, geothermal, and solid minerals agreements, *25 CFR 225.1* et seq.

Minerals Management Service, Department of the Interior--General, *30 CFR 201.100* et seq.

Minerals Management Service, Department of the Interior--Royalties, *30 CFR 202.51* et seq.

Minerals Management Service, Department of the Interior--Relief or reduction in royalty rates, *30 CFR 203.0* et seq.

Minerals Management Service, Department of the Interior--Penalties, *30 CFR 241.50* et seq.

Bureau of Land Management, Department of the Interior--Geothermal resources leasing, *43 CFR 3200.1* et seq.

Bureau of Land Management, Department of the Interior--Leasing of solid minerals other than coal and oil shale, *43 CFR 3501.1* et seq.

Bureau of Land Management, Department of the Interior--Solid minerals (other than coal) exploration and mining operations, *43 CFR 3590.0-1* et seq.

Bureau of Land Management, Department of the Interior--Management of oil shale exploration and leases, *43 CFR 3930.10* et seq.

Related Statutes & Rules:

This section is referred to in *25 USCS § 396f*.

Research Guide:

Annotations:

Application of Indian Mineral Leasing Act (IMLA) and Its Implementing Regulations. *196 ALR Fed 619*.

Texts:

1 Energy Law & Transactions (Matthew Bender), ch 21, Leasing on Federal Lands: Onshore § 21.05.

Law Review Articles:

Juliano. Conflicted Justice: The Department of Justice's Conflict of Interest in Representing Native American Tribes. *37 Ga L Rev 1307*, Summer 2003.

LeBeau. Reclaiming Reservation Infrastructure: Regulatory and Economic Opportunities for Tribal Development. *12 Stan L & Pol'y Rev 237*, Spring 2001.

Marsh. Secretarial Discretion in Communitization of Indian Oil and Gas Leases: The Tenth Circuit Speaks With A Forked Tongue. *32 Tulsa LJ 779*, Summer 1997.

Interpretive Notes and Decisions:

1. Generally 2. Construction 3. Jurisdiction

**1. Generally**

## 25 USCS § 396d

Secretary of Interior has promulgated regulations which limit state and local regulation of use of Indian Property, and which require lessees to carry out and observe all operation and development regulations governing oil and gas operations on restricted Indian lands. *Samedan Oil Corp. v Cotton Petroleum Corp.* (1978, WD Okla) 466 F Supp 521, 64 OGR 519.

## 2. Construction

Navajo Indian Tribe may impose taxes on value of leasehold interests in tribal lands and on receipts from sale of property produced or extracted or sale of services within those lands without first obtaining approval of Secretary of Interior; neither Indian Reorganization Act of 1934 (25 USCS §§ 461 et seq.) nor Indian Mineral Lease Act of 1938 (25 USCS §§ 396a et seq.) requires Secretarial approval of Navajo tax laws, and statutes requiring Secretarial supervision in other contexts do not reveal that Congress has limited tribe's authority to tax non-Indians. *Kerr-McGee Corp. v Navajo Tribe of Indians* (1985) 471 US 195, 85 L Ed 2d 200, 105 S Ct 1900, 84 OGR 213.

Section 4 of Indian Mineral Leasing Act of 1938, 25 USCS § 396d, simply remitted coal leases, in common with all mineral leases, to governance of rules and regulations promulgated by Secretary of Interior; Act and regulations imposed no fiduciary responsibilities supporting claim for damages against defendant United States regarding Secretary of Interior's approval of coal lease between plaintiff Indian tribe and lessee. *United States v Navajo Nation* (2003) 537 US 488, 155 L Ed 2d 60, 123 S Ct 1079, 2003 CDOS 1897, 16 FLW Fed S 99, on remand, remanded (2003, CA FC) 347 F3d 1327, reh den, reh, en banc, den (2004, CA FC) 2004 US App LEXIS 6041 and reh den, reh, en banc, den (2004, CA FC) 2004 US App LEXIS 6042.

Mineral Leasing Act of 1938 (25 USCS §§ 396 et seq.) has not pre-empted all power of Navajo Tribe to tax non-Indian lessees, and has specifically not precluded Tribe from imposing property and business activities tax on mineral lessee. *Kerr-McGee Corp. v Navajo Tribe of Indians* (1984, CA9 Ariz) 731 F2d 597, affd (1985) 471 US 195, 85 L Ed 2d 200, 105 S Ct 1900, 84 OGR 213.

## 3. Jurisdiction

Action by Indian tribes attacking oil "pooling" of their lands with other lands by order of the state conservation commission did not establish the \$ 10,000 jurisdictional amount, since the matter in controversy was not the lands or the royalties, but the regulation and the right to be free from it; commission's order did not purport to divest the tribes of their property and did not appear to impair their lease rights or interfere with any other property interest. *Yoder v Assiniboine & Sioux Tribes of Ft. Peck Indian Reservation* (1964, CA9 Mont) 339 F2d 360.



LEXSTAT 25 U.S.C. 396A

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\*\*\* CURRENT THROUGH PL 111-138, APPROVED 2/1/2010, WITH A GAP OF P.L. 111-127 \*\*\*

TITLE 25. INDIANS  
CHAPTER 12. LEASE, SALE, OR SURRENDER OF ALLOTTED OR UNALLOTTED LANDS

**Go to the United States Code Service Archive Directory**

*25 USCS § 396e*

§ 396e. Officials authorized to approve leases

The Secretary of the Interior may, in his discretion, authorize superintendents or other officials in the Indian Service to approve leases for oil, gas, or other mining purposes covering any restricted Indian lands, tribal or allotted.

**HISTORY:**

(May 11, 1938, ch 198, § 5, 52 Stat. 348.)

**HISTORY; ANCILLARY LAWS AND DIRECTIVES**

Transfer of functions:

Reorg. Plan No. 3, of 1950, §§ 1, 2, which appears as *5 USCS § 903* note, transferred all functions, with two exceptions, of all other officers of the Department of the Interior and all functions of all agencies and employees of such Department, to the Secretary of the Interior, with the power to authorize the performance of any function of the Secretary of the Interior by any other officer or by any agency of the Department of the Interior.

Other provisions:

**Repeal of inconsistent Acts.** Act May 11, 1938, ch 198, § 7, 52 Stat. 348, provided: "All Act [Acts] or parts of Acts inconsistent herewith are hereby repealed."

**NOTES:**

Code of Federal Regulations:

Bureau of Indian Affairs, Department of the Interior--Leasing of tribal lands for mineral development, *25 CFR 211.1* et seq.

Bureau of Indian Affairs, Department of the Interior--Leasing of allotted lands for mineral development, *25 CFR 212.1* et seq.

Bureau of Indian Affairs, Department of the Interior--Surface exploration, mining, and reclamation of lands, *25 CFR 216.1* et seq.

25 USCS § 396e

Bureau of Indian Affairs, Department of the Interior--Management of tribal assets of Ute Indian Tribe, Uintah and Ouray Reservation, Utah, by the Tribe and the Ute Distribution Corp, *25 CFR 217.1* et seq.

Bureau of Indian Affairs, Department of the Interior--Oil and gas, geothermal, and solid minerals agreements, *25 CFR 225.1* et seq.

Minerals Management Service, Department of the Interior--General, *30 CFR 201.100* et seq.

Minerals Management Service, Department of the Interior--Royalties, *30 CFR 202.51* et seq.

Minerals Management Service, Department of the Interior--Relief or reduction in royalty rates, *30 CFR 203.0* et seq.

Minerals Management Service, Department of the Interior--Penalties, *30 CFR 241.50* et seq.

Research Guide:

Annotations:

Application of Indian Mineral Leasing Act (IMLA) and Its Implementing Regulations. *196 ALR Fed 619*.

Texts:

Cohen's Handbook of Federal Indian Law (Matthew Bender), ch 17, Natural Resources § 17.03.

Interpretive Notes and Decisions:

Full-blood Creek Indian's deed to lands, which had been purchased for her with funds derived from royalties reserved in an oil and gas lease on her restricted allotment and held in trust by the Secretary of the Interior, was ineffectual, where it was not approved by the Secretary, though approved by assistant superintendent of the Five Civilized Tribes; *25 USCS § 396e* indicates that Congress regarded congressional authorization necessary in order to permit the Secretary to delegate to superintendent or other officials in the Indian service the power to approve leases covering restricted Indian lands. *United States v Watashe (1939, CA10 Okla) 102 F2d 428*.



LEXSTAT 25 U.S.C. 396A

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\*\*\* CURRENT THROUGH PL 111-138, APPROVED 2/1/2010, WITH A GAP OF P.L. 111-127 \*\*\*

TITLE 25. INDIANS  
CHAPTER 12. LEASE, SALE, OR SURRENDER OF ALLOTTED OR UNALLOTTED LANDS

**Go to the United States Code Service Archive Directory**

*25 USCS § 396f*

§ 396f. Lands excepted from leasing provisions

Sections 1, 2, 3, and 4 of this Act [25 USCS §§ 396a-396d] shall not apply to the Crow Reservation in Montana, the ceded lands of the Shoshone Reservation in Wyoming, the Osage Reservation in Oklahoma, nor to the coal and asphalt lands of the Choctaw and Chickasaw Tribes in Oklahoma.

**HISTORY:**

(May 11, 1938, ch 198, § 6, 52 Stat. 348; May 27, 1955, ch 106, § 2, 69 Stat. 68.)

**HISTORY; ANCILLARY LAWS AND DIRECTIVES**

**Amendments:**

1955. Act May 27, 1955, deleted "the Papago Indian Reservation in Arizona," following "shall not apply to".

**Other provisions:**

**Repeal of inconsistent Acts.** Act May 11, 1938, ch 198, § 7, 52 Stat. 348, provided: "All Act [Acts] or parts of Acts inconsistent herewith are hereby repealed."

**Papago Indian reservation.** Act May 27, 1955, ch 106, § 1, 69 Stat. 67, which appears as 25 USCS § 463 note, authorized the leasing of minerals for mining purposes.

**NOTES:**

**Code of Federal Regulations:**

Bureau of Indian Affairs, Department of the Interior--Leasing of tribal lands for mineral development, 25 CFR 211.1 et seq.

Bureau of Indian Affairs, Department of the Interior--Leasing of allotted lands for mineral development, 25 CFR 212.1 et seq.

25 USCS § 396f

Bureau of Indian Affairs, Department of the Interior--Surface exploration, mining, and reclamation of lands, *25 CFR 216.1* et seq.

Bureau of Indian Affairs, Department of the Interior--Management of tribal assets of Ute Indian Tribe, Uintah and Ouray Reservation, Utah, by the Tribe and the Ute Distribution Corp, *25 CFR 217.1* et seq.

Bureau of Indian Affairs, Department of the Interior--Oil and gas, geothermal, and solid minerals agreements, *25 CFR 225.1* et seq.

Minerals Management Service, Department of the Interior--General, *30 CFR 201.100* et seq.

Minerals Management Service, Department of the Interior--Royalties, *30 CFR 202.51* et seq.

Minerals Management Service, Department of the Interior--Relief or reduction in royalty rates, *30 CFR 203.0* et seq.

Minerals Management Service, Department of the Interior--Penalties, *30 CFR 241.50* et seq.

Research Guide:

Texts:

Cohen's Handbook of Federal Indian Law (Matthew Bender), ch 4, Indian Tribal Governments § 4.07.

Cohen's Handbook of Federal Indian Law (Matthew Bender), ch 17, Natural Resources § 17.03.

Law Review Articles:

Applicability of State Conservation and Other Laws to Indian and Public Lands. 16 Rocky Mt Min L Inst 347, 1970.



LEXSTAT 25 U.S.C. 396A

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\*\*\* CURRENT THROUGH PL 111-138, APPROVED 2/1/2010, WITH A GAP OF P.L. 111-127 \*\*\*

TITLE 25. INDIANS  
CHAPTER 12. LEASE, SALE, OR SURRENDER OF ALLOTTED OR UNALLOTTED LANDS

Go to the United States Code Service Archive Directory

25 USCS § 396g

§ 396g. Subsurface storage of oil or gas

The Secretary of the Interior, to avoid waste or to promote the conservation of natural resources or the welfare of the Indians, is hereby authorized in his discretion to approve leases of lands that are subject to lease under section 1 of this Act [25 USCS § 396a] or the Act of March 3, 1909 (35 Stat. 783, 25 U.S.C. 396), for the subsurface storage of oil and gas, irrespective of the lands from which initially produced, and the Secretary is hereby authorized, in order to provide for the subsurface storage of oil or gas, to approve modifications, amendments, or extensions of the oil and gas or other mining lease(s), if any, in effect as to restricted Indian lands, tribal or allotted, and may promulgate rules and regulations consistent with such leases, modifications, amendments, and extensions, relating to the storage of oil or gas thereunder. Any such leases may provide for the payment of a storage fee or rental on such stored oil or gas or, in lieu of such fee or rental, for a royalty other than that prescribed in the lease when such stored oil or gas is produced in conjunction with oil or gas not previously produced. It may be provided that any oil and gas lease under which storage of oil or gas is so authorized shall be continued in effect at least for the period of such storage use and so long thereafter as oil or gas not previously produced is produced in paying quantities.

**HISTORY:**

(May 11, 1938, ch 198, § 8, as added Aug. 1, 1956, ch 808, 70 Stat. 774.)

**HISTORY; ANCILLARY LAWS AND DIRECTIVES**

**Other provisions:**

**Repeal of inconsistent Acts.** Act May 11, 1938, ch 198, § 7, 52 Stat. 348, provided: "All Act [Acts] or parts of Acts inconsistent herewith are hereby repealed."

**NOTES:**

**Code of Federal Regulations:**

Bureau of Indian Affairs, Department of the Interior--Leasing of tribal lands for mineral development, 25 CFR 211.1 et seq.

Bureau of Indian Affairs, Department of the Interior--Leasing of allotted lands for mineral development, 25 CFR 212.1 et seq.

25 USCS § 396g

Bureau of Indian Affairs, Department of the Interior--Oil and gas, geothermal, and solid minerals agreements, *25 CFR 225.1* et seq.

Minerals Management Service, Department of the Interior--General, *30 CFR 201.100* et seq.

Minerals Management Service, Department of the Interior--Royalties, *30 CFR 202.51* et seq.

Minerals Management Service, Department of the Interior--Relief or reduction in royalty rates, *30 CFR 203.0* et seq.

Minerals Management Service, Department of the Interior--Penalties, *30 CFR 241.50* et seq.

Bureau of Land Management, Department of the Interior--Solid minerals (other than coal) exploration and mining operations, *43 CFR 3590.0-1* et seq.

Research Guide:

Federal Procedure:

19 Fed Proc L Ed, Indians and Indian Affairs § 46:191.



LEXSTAT 25 USCS § 397

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TITLE 25. INDIANS  
CHAPTER 12. LEASE, SALE, OR SURRENDER OF ALLOTTED OR UNALLOTTED LANDS

Go to the United States Code Service Archive Directory

25 USCS § 397

§ 397. Leases of lands for grazing or mining

Where lands are occupied by Indians who have bought and paid for the same, and which lands are not needed for farming or agricultural purposes, and are not desired for individual allotments, the same may be leased by authority of the council speaking for such Indians, for a period not to exceed five years for grazing, or ten years for mining purposes in such quantities and upon such terms and conditions as the agent in charge of such reservation may recommend, subject to the approval of the Secretary of the Interior.

**HISTORY:**

(Feb. 28, 1891, ch 383, § 3, 26 Stat. 795.)

**HISTORY; ANCILLARY LAWS AND DIRECTIVES**

**Transfer of functions:**

Reorg. Plan No. 3, of 1950, §§ 1, 2, which appears as 5 USCS § 903 note, transferred all functions, with two exceptions, of all other officers of the Department of the Interior and all functions of all agencies and employees of such Department, to the Secretary of the Interior, with the power to authorize the performance of any function of the Secretary of the Interior by any other officer or by any agency of the Department of the Interior.

**NOTES:**

**Code of Federal Regulations:**

Bureau of Indian Affairs, Department of the Interior--Leases and permits, 25 CFR 162.100 et seq.  
Bureau of Indian Affairs, Department of the Interior--Grazing permits, 25 CFR 166.1 et seq.  
Bureau of Indian Affairs, Department of the Interior--Navajo grazing regulations, 25 CFR 167.1 et seq.  
Minerals Management Service, Department of the Interior--General, 30 CFR 201.100 et seq.  
Minerals Management Service, Department of the Interior--Royalties, 30 CFR 202.51 et seq.  
Minerals Management Service, Department of the Interior--Relief or reduction in royalty rates, 30 CFR 203.0 et seq.  
Minerals Management Service, Department of the Interior--Records and files maintenance, 30 CFR 212.50 et seq.  
Minerals Management Service, Department of the Interior--Penalties, 30 CFR 241.50 et seq.  
Bureau of Land Management, Department of the Interior--Onshore oil and gas operations, 43 CFR 3160.0-1 et seq.

## 25 USCS § 397

## Related Statutes &amp; Rules:

Cherokee Outlet, provisions inapplicable to, 25 USCS § 371.

Unallotted lands authorized to be leased for oil and gas mining purposes, 25 USCS § 398.

Lands held in trust may be leased by allottee for period not to exceed five years under rules and regulations of Secretary of Interior, 25 USCS § 403.

This section is referred to in 25 USCS § 398.

## Research Guide:

## Federal Procedure:

19 Fed Proc L Ed, Indians and Indian Affairs § 46:175.

## Texts:

Cohen's Handbook of Federal Indian Law (Matthew Bender), ch 17, Natural Resources §§ 17.01-17.03.

## Law Review Articles:

Survey after Lease Issues--Federal and Indian Lands. 11 Rocky Mt Min L Inst 473, 1966.

Applicability of State Conservation and Other Laws to Indian and Public Lands. 16 Rocky Mt Min L Inst 347, 1970.

LeBeau. Reclaiming Reservation Infrastructure: Regulatory and Economic Opportunities for Tribal Development. 12 Stan L & Pol'y Rev 237, Spring 2001.

EagleWoman; WasteWin. Tribal Nation Economics: Rebuilding Commercial Prosperity in Spite of U.S. Trade Restrictions--Recommendations for Economic Revitalization in Indian Country. 44 Tulsa L Rev 383, Winter 2008.

Ansson. The Navajo Nation's Aneth Extension and the Utah Navajo Trust Fund: Who Should Govern the Fund after Years of Misuse? 14 TM Cooley L Rev 555, 1997.

## Interpretive Notes and Decisions:

1. Generally 2. Authority of Congress 3. Rights and liabilities of lessees 4. Parties

**1. Generally**

Act of legislature of Oklahoma Territory providing for taxation of cattle grazing upon Indian lands under duly authorized leases was not an invasion of right of United States to control Indian lands. *Thomas v Gay* (1898) 169 US 264, 42 L Ed 740, 18 S Ct 340.

Indictment against Indian agent for soliciting and accepting bribes in connection with the execution and completion of leases stated a public offense. *Sharp v United States* (1905, CA8 Okla) 138 F 878.

Fee increase for grazing permits on Indian land which was announced October 3, 1979, was invalid where grazing permits explicitly provide that fees shall be re-evaluated by August 1, since provision clearly indicates that any change in fees must have been made and announced by August 1, 1979. *Danks v Fields* (1982, CA8 ND) 696 F2d 572.

In a suit by the United States as guardian of the Seneca Nation of Indians to cancel leases on lands of such Indians, the equities available against the Indian nation are available against the United States. *United States v Adamic* (1943, DC NY) 54 F Supp 221.

## 25 USCS § 397

Policy 25 USCS § 397 is to give Secretary supervision over leasing of allotted lands, and court will not interfere to appoint a receiver for the collection of rents. *Smith v United States* (1905, CCD Or) 142 F 225.

The determination of the council upon the question of leasing is conclusive upon the government, in the absence of fraud. *White Bear v Barth* (1921) 61 Mont 322, 203 P 517.

The words "bought and paid for" apply to all lands purchased by the Indians, either by the payment of money, or exchange, or by the surrender of possession of other property. *Strawberry Valley Cattle Co. v Chipman* (1896) 13 Utah 454, 45 P 348.

## 2. Authority of Congress

Congress could grant a preferential right to purchase Indian lands, in consideration of relinquishment by lessee of rights under a mining lease, without assent of Indians. *Wadsworth v Boysen* (1906, CA8 Wyo) 148 F 771.

Acts of Congress, extending the reservation of mineral rights in lands of the Osage Tribe, were not unconstitutional as to purchasers of such land from allottees. *Adams v Osage Tribe of Indians* (1931, DC Okla) 50 F2d 918, affd (1932, CA10 Okla) 59 F2d 653, cert den (1932) 287 US 652, 77 L Ed 563, 53 S Ct 116.

## 3. Rights and liabilities of lessees

Where lease of mineral lands within the Blackfeet Indian reservation, a reservation created by legislation, was given by the tribal council and approved by the Secretary, lessee was subject to gross production and net proceeds taxes imposed by state. *British-American Oil Producing Co. v Board of Equalization* (1936) 299 US 159, 81 L Ed 95, 57 S Ct 132, reh den (1937) 299 US 624, 81 L Ed 459, 57 S Ct 314.

There could be no liability under a lease until it was approved by the Secretary. *Lemmon v United States* (1901, CA8 Neb) 106 F 650.

Lessee, under authority of 25 USCS § 397, could not drill or bore oil wells within cultivated enclosure, where lease expressly prohibited it. *Barnsdall Oil Co. v Leahy* (1912, CA8 Okla) 195 F 731.

Where it does not appear that any of provisions of contract for lease of land was inserted without authority of the tribe, defendant lessee could not defend on ground that agreement for payment of additional sum for grazing excessive cattle was in violation of 25 USCS § 179 and therefore void. *Kirby v United States* (1921, CA9 Mont) 273 F 391, affd (1922) 260 US 423, 67 L Ed 329, 43 S Ct 144.

Where allottee leased land in accordance with the provisions of 25 USCS § 397 and then executed a deed of conveyance without authority, the United States could maintain an action to set the deed aside. *United States v Dooley* (1906, CCD Wash) 151 F 697.

## 4. Parties

The United States has capacity to sue to recover damages for breach of a lease made by allottee with approval of Secretary. *United States v Gray* (1912, CA8 Utah) 201 F 291.

The United States, in suing as guardian of the Seneca Nation of Indians to have leases on lands of such Indians cancelled, was suing in its sovereign capacity and in the carrying out of a governmental policy, and its authority to bring such suit cannot be questioned. *United States v Adamic* (1943, DC NY) 54 F Supp 221.

In a suit by the United States as guardian of the Seneca Nation of Indians to cancel leases on lands of the Indians, the United States Indian agent for the New York Indian agency was not an essential plaintiff, notwithstanding the provisions of Act Feb. 28, 1901 (31 Stat. 819) that all moneys which belong to the Seneca Nation of New York Indians arising from leases shall be paid to and be recoverable to such agent for and in the name of the Indian Nation. *United States v Adamic* (1943, DC NY) 54 F Supp 221.

In suit by the United States as guardian of the Seneca Nation of Indians to cancel leases on lands of such Indians, there was no defect of parties on account of the absence of the Indians as parties. *United States v Adamic* (1943, DC NY) 54 F Supp 221.



LEXSTAT 25 USCS § 398

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TITLE 25. INDIANS  
CHAPTER 12. LEASE, SALE, OR SURRENDER OF ALLOTTED OR UNALLOTTED LANDS

Go to the United States Code Service Archive Directory

25 USCS § 398

§ 398. Leases of unallotted lands for oil and gas mining purposes

Unallotted land on Indian reservations other than lands of the Five Civilized Tribes and the Osage Reservation subject to lease for mining purposes for a period of ten years under section 3 of the Act of February 28, 1891 (Twenty-sixth Statutes at Large, page 795) [25 USCS § 397] may be leased at public auction by the Secretary of the Interior, with the consent of the council speaking for such Indians for oil and gas mining purposes for a period of not to exceed ten years, and as much longer as oil or gas shall be found in paying quantities, and the terms of any existing oil and gas mining lease may in like manner be amended by extending the term thereof for as long as oil or gas shall be found in paying quantities: *Provided*, That the production of oil and gas and other minerals on such lands may be taxed by the State in which said lands are located in all respects the same as production on unrestricted lands, and the Secretary of the Interior is authorized and directed to cause to be paid the tax so assessed against the royalty interests on said lands: *Provided, however*, That such tax shall not become a lien or charge of any kind or character against the land or the property of the Indian owner.

**HISTORY:**

(May 29, 1924, ch 210, 43 Stat. 244.)

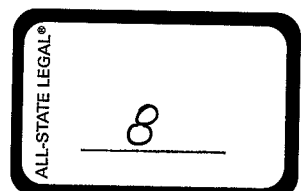
**NOTES:**

Code of Federal Regulations:

Minerals Management Service, Department of the Interior--General, 30 CFR 201.100 et seq.  
Minerals Management Service, Department of the Interior--Royalties, 30 CFR 202.51 et seq.  
Minerals Management Service, Department of the Interior--Relief or reduction in royalty rates, 30 CFR 203.0 et seq.  
Minerals Management Service, Department of the Interior--Records and files maintenance, 30 CFR 212.50 et seq.  
Minerals Management Service, Department of the Interior--Penalties, 30 CFR 241.50 et seq.  
Bureau of Land Management, Department of the Interior--Onshore oil and gas operations, 43 CFR 3160.0-1 et seq.

Related Statutes & Rules:

This section is referred to in 25 USCS § 398a.



## 25 USCS § 398

## Research Guide:

## Am Jur:

41 *Am Jur 2d, Indians; Native Americans* § 71.

## Texts:

Cohen's Handbook of Federal Indian Law (Matthew Bender), ch 4, Indian Tribal Governments § 4.01.

Cohen's Handbook of Federal Indian Law (Matthew Bender), ch 6, Tribal/State Relationship § 6.04.

Cohen's Handbook of Federal Indian Law (Matthew Bender), ch 17, Natural Resources § 17.03.

## Law Review Articles:

Problems in Development of Mineral Resources on Indian Lands. 7 *Rocky Mt Min L Inst* 661, 1962.

Indian Lands--Minerals--Related Problems. 14 *Rocky Mt Min L Inst* 89, 1968.

Eagle Woman; Waste Win. Tribal Nation Economics: Rebuilding Commercial Prosperity in Spite of U.S. Trade Re-  
straints--Recommendations for Economic Revitalization in Indian Country. 44 *Tulsa L Rev* 383, Winter 2008.

Ansson. The Navajo Nation's Aneth Extension and the Utah Navajo Trust Fund: Who Should Govern the Fund after  
Years of Misuse? 14 *TM Cooley L Rev* 555, 1997.

## Interpretive Notes and Decisions:

## 1. Generally 2. Construction

## 1. Generally

Notwithstanding 30 *USCS* § 226 the Secretary of the Interior had discretion not to lease Indian land to first qual-  
ified applicant, and determine to sell leases under regulations relating to the leasing of Indian lands. *Pease v Udall*  
(1964, CA9 Alaska) 332 F2d 62, 20 OGR 941.

## 2. Construction

General provisions relating to leasing of Indian lands are applicable to the leasing of lands of Blackfeet Indians  
notwithstanding special provisions. *British-American Oil Producing Co. v Board of Equalization* (1936) 299 *US* 159,  
81 *L Ed* 95, 57 *S Ct* 132, reh den (1937) 299 *US* 624, 81 *L Ed* 459, 57 *S Ct* 314.

State cannot tax Indian royalty income from oil and gas leases issued to nonIndian lessees pursuant to Indian Min-  
eral Leasing Act of 1938 (25 *USCS* §§ 396a et seq.); provision of 25 *USCS* § 398 authorizing states to tax royalty inter-  
est of Indian tribes is not incorporated in 1938 Act. *Montana v Blackfeet Tribe of Indians* (1985) 471 *US* 759, 85 *L Ed*  
2d 753, 105 *S Ct* 2399, 84 OGR 630 (criticized in *Navajo Nation v HHS* (2002, CA9 Ariz) 285 F3d 864, 2002 CDOS  
3021, 2002 Daily Journal DAR 3682).

State taxing authority provided for in provisions of 25 *USCS* § 398 is not impliedly repealed by provisions of 25  
*USCS* §§ 396a et seq. or Indian Reorganization Act (25 *USCS* § 476). *Blackfeet Tribe of Indians v Montana* (1984,  
CA9 Mont) 729 F2d 1192, 82 OGR 189, affd (1985) 471 *US* 759, 85 *L Ed* 2d 753, 105 *S Ct* 2399, 84 OGR 630 (criti-  
cized in *Navajo Nation v HHS* (2002, CA9 Ariz) 285 F3d 864, 2002 CDOS 3021, 2002 Daily Journal DAR 3682).



LEXSTAT 25 USCS § 398A

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TITLE 25. INDIANS  
CHAPTER 12. LEASE, SALE, OR SURRENDER OF ALLOTTED OR UNALLOTTED LANDS

**Go to the United States Code Service Archive Directory**

*25 USCS § 398a*

§ 398a. Leases of unallotted lands for oil and gas mining purposes within Executive order Indian reservations

Unallotted lands within the limits of any reservation or withdrawal created by Executive order for Indian purposes or for the use or occupancy of any Indians or tribe may be leased for oil and gas mining purposes in accordance with the provisions contained in the Act of May 29, 1924 (Forty-third Statutes, page 244) [25 USCS § 398].

**HISTORY:**

(March 3, 1927, ch 299, § 1, 44 Stat. 1347.)

**NOTES:**

Code of Federal Regulations:

Minerals Management Service, Department of the Interior--General, *30 CFR 201.100* et seq.  
Minerals Management Service, Department of the Interior--Royalties, *30 CFR 202.51* et seq.  
Minerals Management Service, Department of the Interior--Relief or reduction in royalty rates, *30 CFR 203.0* et seq.  
Minerals Management Service, Department of the Interior--Records and files maintenance, *30 CFR 212.50* et seq.  
Minerals Management Service, Department of the Interior--Penalties, *30 CFR 241.50* et seq.  
Bureau of Land Management, Department of the Interior--Onshore oil and gas operations, *43 CFR 3160.0-1* et seq.

Research Guide:

Texts:

Cohen's Handbook of Federal Indian Law (Matthew Bender), ch 8, Taxation § 8.03.  
Cohen's Handbook of Federal Indian Law (Matthew Bender), ch 15, Tribal Property § 15.09.  
Cohen's Handbook of Federal Indian Law (Matthew Bender), ch 17, Natural Resources § 17.03.

Law Review Articles:

25 USCS § 398a

LeBeau. Reclaiming Reservation Infrastructure: Regulatory and Economic Opportunities for Tribal Development. *12 Stan L & Pol'y Rev* 237, Spring 2001.

EagleWoman; WasteWin. Tribal Nation Economics: Rebuilding Commercial Prosperity in Spite of U.S. Trade Re-straints--Recommendations for Economic Revitalization in Indian Country. *44 Tulsa L Rev* 383, Winter 2008.

Ansson. The Navajo Nation's Aneth Extension and the Utah Navajo Trust Fund: Who Should Govern the Fund after Years of Misuse? *14 TM Cooley L Rev* 555, 1997.

Interpretive Notes and Decisions:

General provisions relating to leasing of Indian lands are applicable to the leasing of lands of Blackfeet Indians notwithstanding special provisions. *British-American Oil Producing Co. v Board of Equalization* (1936) 299 US 159, 81 L Ed 95, 57 S Ct 132, reh den (1937) 299 US 624, 81 L Ed 459, 57 S Ct 314.

Notwithstanding 30 USCS § 226 the Secretary of the Interior had discretion not to lease Indian land to first qualified applicant, and determine to sell leases under regulations relating to the leasing of Indian lands. *Pease v Udall* (1964, CA9 Alaska) 332 F2d 62, 20 OGR 941.



LEXSTAT 25 USCS § 398C

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TITLE 25. INDIANS  
CHAPTER 12. LEASE, SALE, OR SURRENDER OF ALLOTTED OR UNALLOTTED LANDS

Go to the United States Code Service Archive Directory

*25 USCS § 398c*

§ 398c. Taxes

Taxes may be levied and collected by the State or local authority upon improvements, output of mines or oil and gas wells or other rights, property, or assets of any lessee upon lands within Executive order Indian reservations in the same manner as such taxes are otherwise levied and collected, and such taxes may be levied against the share obtained for the Indians as bonuses, rentals, and royalties, and the Secretary of the Interior is hereby authorized and directed to cause such taxes to be paid out of the tribal funds in the Treasury: *Provided*, That such taxes shall not become a lien or charge of any kind against the land or other property of such Indians.

**HISTORY:**

(March 3, 1927, ch 299, § 3, 44 Stat. 1347.)

**NOTES:**

Code of Federal Regulations:

Minerals Management Service, Department of the Interior--General, *30 CFR 201.100* et seq.  
Minerals Management Service, Department of the Interior--Royalties, *30 CFR 202.51* et seq.  
Minerals Management Service, Department of the Interior--Relief or reduction in royalty rates, *30 CFR 203.0* et seq.  
Minerals Management Service, Department of the Interior--Records and files maintenance, *30 CFR 212.50* et seq.  
Minerals Management Service, Department of the Interior--Penalties, *30 CFR 241.50* et seq.  
Bureau of Land Management, Department of the Interior--Onshore oil and gas operations, *43 CFR 3160.0-1* et seq.

Research Guide:

Texts:

Cohen's Handbook of Federal Indian Law (Matthew Bender), ch 6, Tribal/State Relationship § 6.04.  
Cohen's Handbook of Federal Indian Law (Matthew Bender), ch 17, Natural Resources § 17.03.

25 USCS § 398c

Law Review Articles:

State Taxation on Indian Reservations. *1966 Utah L Rev* 132, 1966.

Interpretive Notes and Decisions:

1. Generally 2. Construction

**1. Generally**

Where minerals were reserved in trust patent, there was no allotment, and all taxes applied. *British-American Oil Producing Co. v State Bd. of Equalization* (1936) 101 Mont 293, 54 P2d 129, affd (1936) 299 US 159, 81 L Ed 95, 57 S Ct 132, reh den (1937) 299 US 624, 81 L Ed 459, 57 S Ct 314.

**2. Construction**

25 USCS § 398c does not pre-empt tribe's power to levy privilege tax on occupation of severing oil and gas from reservation land even though tax falls on nonmembers of tribe. *Merrion v Jicarilla Apache Tribe* (1982) 455 US 130, 71 L Ed 2d 21, 102 S Ct 894, 72 OGR 617.

With regard to Executive Order reservations, both state and tribe may impose severance taxes on nonmember lessee of oil and gas rights since federal law, even when given most generous construction, does not pre-empt state's oil and gas severance taxes. *Cotton Petroleum Corp. v New Mexico* (1989) 490 US 163, 104 L Ed 2d 209, 109 S Ct 1698, 102 OGR 604.

Taxation of oil and gas production on Jicarilla Apache tribal lands from leases made under Mineral Leasing Act of 1938 (25 USCS §§ 396a-396f) is not authorized by 25 USCS § 398c; absent specific statutory authority, State of New Mexico lacks power to tax Indian property, and may not tax royalties received by Indians from 1938 Act leases. Tax Status of Production of Oil & Gas from *Jicarilla Apache Tribal Lands Under 1938 Indian Mineral Leasing Act* (1979) 86 ID 181.



LEXSTAT 25 USCS § 2101

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\*\*\* CURRENT THROUGH PL 111-138, APPROVED 2/1/2010, WITH A GAP OF P.L. 111-127 \*\*\*

TITLE 25. INDIANS  
CHAPTER 23. DEVELOPMENT OF TRIBAL MINERAL RESOURCES

**Go to the United States Code Service Archive Directory**

*25 USCS § 2101*

§ 2101. Definitions

For the purposes of this Act [25 USCS §§ 2101-2108], the term--

- (1) "Indian" means any individual Indian or Alaska Native who owns land or interests in land the title to which is held in trust by the United States or is subject to a restriction against alienation imposed by the United States;
- (2) "Indian tribe" means any Indian tribe, band, nation, pueblo, community, rancheria, colony, or other group which owns land or interests in land title to which is held in trust by the United States or is subject to a restriction against alienation imposed by the United States; and
- (3) "Secretary" means the Secretary of the Interior.

**HISTORY:**

(Dec. 22, 1982, P.L. 97-382, § 2, 96 Stat. 1938.)

**HISTORY; ANCILLARY LAWS AND DIRECTIVES**

Short titles:

Act Dec. 22, 1982, P.L. 97-382, § 1, 96 Stat. 1938, provides: "This Act [25 USCS §§ 2101-2108] may be cited as the 'Indian Mineral Development Act of 1982'."

**NOTES:**

Code of Federal Regulations:

Bureau of Indian Affairs, Department of the Interior--Leasing of tribal lands for mineral development, 25 CFR 211.1 et seq.

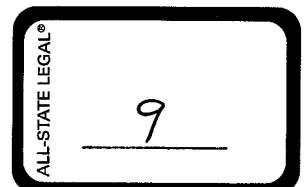
Bureau of Indian Affairs, Department of the Interior--Oil and gas, geothermal, and solid minerals agreements, 25 CFR 225.1 et seq.

Minerals Management Service, Department of the Interior--Royalties, 30 CFR 202.51 et seq.

Minerals Management Service, Department of the Interior--Relief or reduction in royalty rates, 30 CFR 203.0 et seq.

Minerals Management Service, Department of the Interior--Product valuation, 30 CFR 206.10 et seq.

Minerals Management Service, Department of the Interior--Sales agreements or contracts governing the disposal of lease products, 30 CFR 207.1 et seq.



## 25 USCS § 2101

Minerals Management Service, Department of the Interior--Records and files maintenance, *30 CFR 212.50* et seq.  
 Minerals Management Service, Department of the Interior--Collection of royalties, rentals, bonuses and other monies due the Federal Government, *30 CFR 218.10* et seq.  
 Minerals Management Service, Department of the Interior--Penalties, *30 CFR 241.50* et seq.  
 Minerals Management Service, Department of the Interior--Suspensions pending appeal and bonding-royalty management program, *30 CFR 243.1* et seq.

## Research Guide:

## Federal Procedure:

11A Fed Proc L Ed, Environmental Protection § 32:816.  
 19 Fed Proc L Ed, Indians and Indian Affairs § 46:268.

## Am Jur:

41 *Am Jur 2d, Indians; Native Americans* § 67.  
 61C *Am Jur 2d, Pollution Control* § 784.

## Texts:

Cohen's Handbook of Federal Indian Law (Matthew Bender), ch 10, Environmental Regulation in Indian Country § 10.08.  
 Cohen's Handbook of Federal Indian Law (Matthew Bender), ch 17, Natural Resources §§ 17.01, 17.03.  
 1 Energy Law & Transactions (Matthew Bender), ch 21, Leasing on Federal Lands: Onshore § 21.02.

## Law Review Articles:

Hook; Banks. The Indian Mineral Development Act of 1982. *7 Nat Resources & Env't* 11, Spring 1993.

## Interpretive Notes and Decisions:

Indian Mineral Leasing Act of 1938 (IMLA), *25 USCS* §§ 396a et seq., and its regulations imposed no fiduciary responsibilities supporting claim for damages against defendant United States for Secretary of Interior's approval of coal lease between plaintiff Indian tribe and lessee, and Indian Mineral Development Act of 1982, *25 USCS* §§ 2101 et seq., was unavailing to tribe, as it governed Secretary's approval of agreements for development of certain Indian mineral resources through exploration and like activities, but did not establish standards governing Secretary's approval of mining leases negotiated by tribe and third party. *United States v Navajo Nation* (2003) 537 US 488, 155 L Ed 2d 60, 123 S Ct 1079, 2003 CDOS 1897, 16 FLW Fed S 99, on remand, remanded on other grounds (2003, CA FC) 347 F3d 1327, reh den, reh, en banc, den (2004, CA FC) 2004 US App LEXIS 6041 and reh den, reh, en banc, den (2004, CA FC) 2004 US App LEXIS 6042.

Declaratory judgment action arising from disputes regarding oil and gas leases on Indian reservation will not be dismissed, even though Tribe first filed suit against oil companies in tribal court, where tribal court is not properly constituted, because Tribe is adequately represented through trust relationship with Interior Secretary and presence of tribal council members, and underlying cause of action presents federal questions arising under Indian Mineral Development Act (*25 USCS* §§ 2101 et seq.) and regulations promulgated thereunder. *Comstock Oil & Gas, Inc. v Alabama & Coushatta Indian Tribes* (1999, ED Tex) 78 F Supp 2d 589 (criticized in *Am. Greyhound Racing, Inc. v Hull* (2001, DC Ariz) 146 F Supp 2d 1012) and affd in part and revd in part on other grounds, remanded (2001, CA5 Tex) 261 F3d 567,

25 USCS § 2101

*32 ELR 20029, 154 OGR 93, reh den, reh, en banc, den (2001, CA5 Tex) 275 F3d 1084 and cert den (2002) 535 US 971, 152 L Ed 2d 382, 122 S Ct 1438.*



LEXSTAT 25 USCS § 2101

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TITLE 25. INDIANS  
CHAPTER 23. DEVELOPMENT OF TRIBAL MINERAL RESOURCES

**Go to the United States Code Service Archive Directory**

*25 USCS § 2102*

§ 2102. Minerals Agreement

(a) Authorization for tribes; approval by Secretary. Any Indian tribe, subject to the approval of the Secretary and any limitation or provision contained in its constitution or charter, may enter into any joint venture, operating, production sharing, service, managerial, lease or other agreement, or any amendment, supplement or other modification of such agreement (hereinafter referred to as a "Minerals Agreement") providing for the exploration for, or extraction, processing, or other development of, oil, gas, uranium, coal, geothermal, or other energy or nonenergy mineral resources (hereinafter referred to as "mineral resources") in which such Indian tribe owns a beneficial or restricted interest, or providing for the sale or other disposition of the production or products of such mineral resources.

(b) Inclusion of individual holdings; approval by parties and Secretary. Any Indian owning a beneficial or restricted interest in mineral resources may include such resources in a tribal Minerals Agreement subject to the concurrence of the parties and a finding by the Secretary that such participation is in the best interest of the Indian.

**HISTORY:**

(Dec. 22, 1982, P.L. 97-382, § 3, 96 Stat. 1938.)

**NOTES:**

Code of Federal Regulations:

Bureau of Indian Affairs, Department of the Interior--Leasing of tribal lands for mineral development, *25 CFR 211.1* et seq.

Bureau of Indian Affairs, Department of the Interior--Oil and gas, geothermal, and solid minerals agreements, *25 CFR 225.1* et seq.

Minerals Management Service, Department of the Interior--Royalties, *30 CFR 202.51* et seq.

Minerals Management Service, Department of the Interior--Relief or reduction in royalty rates, *30 CFR 203.0* et seq.

Minerals Management Service, Department of the Interior--Product valuation, *30 CFR 206.10* et seq.

Minerals Management Service, Department of the Interior--Sales agreements or contracts governing the disposal of lease products, *30 CFR 207.1* et seq.

Minerals Management Service, Department of the Interior--Records and files maintenance, *30 CFR 212.50* et seq.

Minerals Management Service, Department of the Interior--Collection of royalties, rentals, bonuses and other monies due the Federal Government, *30 CFR 218.10* et seq.

Minerals Management Service, Department of the Interior--Penalties, *30 CFR 241.50* et seq.

25 USCS § 2102

Minerals Management Service, Department of the Interior--Suspensions pending appeal and bonding-royalty management program, *30 CFR 243.1* et seq.

Related Statutes & Rules:

This section is referred to in *25 USCS § 2107*.

Research Guide:

Federal Procedure:

11A Fed Proc L Ed, Environmental Protection § 32:816.

19 Fed Proc L Ed, Indians and Indian Affairs § 46:268.

Am Jur:

*41 Am Jur 2d, Indians; Native Americans § 67.*

Texts:

Cohen's Handbook of Federal Indian Law (Matthew Bender), ch 17, Natural Resources § 17.03.

Interpretive Notes and Decisions:

Prior to Secretary of Interior's final decision, tribe had right to rescind joint mineral development agreement. *Quantum Exploration, Inc. v Clark* (1986, CA9 Mont) 780 F2d 1457, 90 OGR 81.

"Operating agreement" may sometimes fall within definition of "lease." *Utah v Babbitt* (1995, CA10 Utah) 53 F3d 1145.

Summary judgment is granted to state and Indian tribe trust fund of state in suit for royalties on mineral operating agreement, where tribe and energy company entered into agreement pursuant to Indian Mineral Development Act (IMDA), *25 USCS §§ 2101* et seq., and 1933 Act giving land affected by agreement to tribe had required portion of profits from any leases to go to state for benefit of tribe, 47 Stat 1418, as amended, 82 Stat 121, since both IMDA and the 1933 Act are mineral leasing laws for which definition of lease is broad one found in Federal Oil & Gas Royalty Management Act of 1982, *30 USCS § 1702(5)*, which includes non-lease agreements, like operating agreements and joint ventures, authorized in IMDA. *Utah v Babbitt* (1993, DC Utah) 830 F Supp 586, 127 OGR 173, affd (1995, CA10 Utah) 53 F3d 1145.



LEXSTAT 25 USCS § 2101

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TITLE 25. INDIANS  
CHAPTER 23. DEVELOPMENT OF TRIBAL MINERAL RESOURCES

**Go to the United States Code Service Archive Directory**

*25 USCS § 2103*

§ 2103. Secretary's determination on Minerals Agreement

(a) Time; enforcement. The Secretary shall approve or disapprove any Minerals Agreement submitted to him for approval within (1) one hundred and eighty days after submission or (2) sixty days after compliance, if required, with section 102(2)(C) of the National Environmental Policy Act of 1969 (*42 U.S.C. 4332(2)(C)*), or any other requirement of Federal law, whichever is later. Any party to such an agreement may enforce the provisions of this subsection pursuant to *section 1361 of title 28, United States Code*.

(b) Factors for consideration; extent of required study. In approving or disapproving a Minerals Agreement, the Secretary shall determine if it is in the best interest of the Indian tribe or of any individual Indian who may be party to such agreement and shall consider, among other things, the potential economic return to the tribe; the potential environmental, social, and cultural effects on the tribe; and provisions for resolving disputes that may arise between the parties to the agreement: *Provided*, That the Secretary shall not be required to prepare any study regarding environmental, socioeconomic, or cultural effects of the implementation of a Minerals Agreement apart from that which may be required under section 102(2)(C) of the National Environmental Policy Act of 1969 (*42 U.S.C. 4332(2)(C)*).

(c) Prior notice of proposed findings; privileged information. Not later than thirty days prior to formal approval or disapproval of any Minerals Agreement, the Secretary shall provide written findings forming the basis of his intent to approve or disapprove such agreement to the affected Indian tribe. Notwithstanding any other law, such findings and all projections, studies, data or other information possessed by the Department of the Interior regarding the terms and conditions of the Minerals Agreement, the financial return to the Indian parties thereto, or the extent, nature, value or disposition of the Indian mineral resources, or the production, products or proceeds thereof, shall be held by the Department of the Interior as privileged proprietary information of the affected Indian or Indian tribe.

(d) Delegation; final action; appeal; burden on Secretary. The authority to disapprove agreements under this section may only be delegated to the Assistant Secretary of the Interior for Indian Affairs. The decision of the Secretary or, where authority is delegated, of the Assistant Secretary of the Interior for Indian Affairs, to disapprove a Minerals Agreement shall be deemed a final agency action. The district courts of the United States shall have jurisdiction to review the Secretary's disapproval action and shall determine the matter *de novo*. The burden is on the Secretary to sustain his action.

(e) Nonliability of United States; continuing obligations. Where the Secretary has approved a Minerals Agreement in compliance with the provisions of this Act [*25 USCS §§ 2101-2108*] and any other applicable provision of law, the

25 USCS § 2103

United States shall not be liable for losses sustained by a tribe or individual Indian under such agreement: *Provided*, That the Secretary shall continue to have a trust obligation to ensure that the rights of a tribe or individual Indian are protected in the event of a violation of the terms of any Minerals Agreement by any other party to such agreement: *Provided further*, That nothing in this Act [25 USCS §§ 2101-2108] shall absolve the United States from any responsibility to Indians, including those which derive from the trust relationship and from any treaties, Executive orders, or agreement between the United States and any Indian tribe.

**HISTORY:**

(Dec. 22, 1982, P.L. 97-382, § 4, 96 Stat. 1938.)

**NOTES:**

Code of Federal Regulations:

Bureau of Indian Affairs, Department of the Interior--Leasing of tribal lands for mineral development, 25 CFR 211.1 et seq.

Bureau of Indian Affairs, Department of the Interior--Oil and gas, geothermal, and solid minerals agreements, 25 CFR 225.1 et seq.

Minerals Management Service, Department of the Interior--Royalties, 30 CFR 202.51 et seq.

Minerals Management Service, Department of the Interior--Relief or reduction in royalty rates, 30 CFR 203.0 et seq.

Minerals Management Service, Department of the Interior--Product valuation, 30 CFR 206.10 et seq.

Minerals Management Service, Department of the Interior--Sales agreements or contracts governing the disposal of lease products, 30 CFR 207.1 et seq.

Minerals Management Service, Department of the Interior--Records and files maintenance, 30 CFR 212.50 et seq.

Minerals Management Service, Department of the Interior--Collection of royalties, rentals, bonuses and other monies due the Federal Government, 30 CFR 218.10 et seq.

Minerals Management Service, Department of the Interior--Penalties, 30 CFR 241.50 et seq.

Minerals Management Service, Department of the Interior--Suspensions pending appeal and bonding-royalty management program, 30 CFR 243.1 et seq.

Related Statutes & Rules:

This section is referred to in 25 USCS § 2107.

Research Guide:

Federal Procedure:

11A Fed Proc L Ed, Environmental Protection § 32:816.

19 Fed Proc L Ed, Indians and Indian Affairs §§ 46:268-270.

Am Jur:

41 Am Jur 2d, Indians; Native Americans § 67.

Texts:

Cohen's Handbook of Federal Indian Law (Matthew Bender), ch 17, Natural Resources § 17.03.

Interpretive Notes and Decisions:

25 USCS § 2103

Prior to Secretary of Interior's final decision, tribe had right to rescind joint mineral development agreement.  
*Quantum Exploration, Inc. v Clark* (1986, CA9 Mont) 780 F2d 1457, 90 OGR 81.

Indian Mineral Development Act of 1982, 25 USCS § 2101 et seq., was not intended to create evidentiary privilege that would remove information protected thereby from reach of discovery; therefore, court included 25 USCS § 2103(c) within definition of "Applicable Confidentiality Laws" in confidentiality agreement and protective order that were to be issued in case between Indian nation and *U.S. Jicarilla Apache Nation v United States* (2004) 60 Fed Cl 611.



LEXSTAT 25 USCS § 2101

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TITLE 25. INDIANS  
CHAPTER 23. DEVELOPMENT OF TRIBAL MINERAL RESOURCES

**Go to the United States Code Service Archive Directory**

*25 USCS § 2104*

§ 2104. Secretary's review of prior Minerals Agreements

(a) Time; criteria; notice of modifications; time for compliance; effect of noncompliance. the [The] Secretary shall review within ninety days of enactment of this Act [enacted Dec. 22, 1982], any existing Minerals Agreement, which does not purport to be a lease, entered into by any Indian tribe and approved by the Secretary after January 1, 1975, but prior to enactment of this Act [enacted Dec. 22, 1982], to determine if such agreement complies with the purposes of this Act [25 USCS §§ 2101-2108]. Such review shall be limited to the terms of the agreement and shall not address questions of the parties' compliance therewith. The Secretary shall notify the affected tribe and other parties to the agreement of any modifications necessary to bring an agreement into compliance with the purposes of this Act [25 USCS §§ 2101-2108]. The tribe and other parties to such agreement shall within ninety days after notice make such modifications. If such modifications are not made within ninety days, the provisions of this Act [25 USCS §§ 2101-2108] may not be used as a defense in any proceeding challenging the validity of the agreement.

(b) Review before promulgation of regulations; not Federal action. The review required by subsection (a) of this section may be performed prior to the promulgation of regulations required under section 8 of this Act [25 USCS § 2107] and shall not be considered a Federal action within the meaning of that term in section 102(2)(C) of the National Environmental Protection Act of 1969 (42 U.S.C. 4332(2)(C)).

**HISTORY:**

(Dec. 22, 1982, P.L. 97-382, § 5, 96 Stat. 1939.)

**HISTORY; ANCILLARY LAWS AND DIRECTIVES**

**Explanatory notes:**

The bracketed word "The" has been inserted in subsec. (a) to indicate the probable intent of Congress to capitalize such word.

**NOTES:**

Code of Federal Regulations:

25 USCS § 2104

Bureau of Indian Affairs, Department of the Interior--Leasing of tribal lands for mineral development, *25 CFR 211.1* et seq.

Bureau of Indian Affairs, Department of the Interior--Oil and gas, geothermal, and solid minerals agreements, *25 CFR 225.1* et seq.

Minerals Management Service, Department of the Interior--Royalties, *30 CFR 202.51* et seq.

Minerals Management Service, Department of the Interior--Relief or reduction in royalty rates, *30 CFR 203.0* et seq.

Minerals Management Service, Department of the Interior--Product valuation, *30 CFR 206.10* et seq.

Minerals Management Service, Department of the Interior--Sales agreements or contracts governing the disposal of lease products, *30 CFR 207.1* et seq.

Minerals Management Service, Department of the Interior--Records and files maintenance, *30 CFR 212.50* et seq.

Minerals Management Service, Department of the Interior--Collection of royalties, rentals, bonuses and other monies due the Federal Government, *30 CFR 218.10* et seq.

Minerals Management Service, Department of the Interior--Penalties, *30 CFR 241.50* et seq.

Minerals Management Service, Department of the Interior--Suspensions pending appeal and bonding-royalty management program, *30 CFR 243.1* et seq.

Research Guide:

Federal Procedure:

11A Fed Proc L Ed, Environmental Protection § 32:816.

Am Jur:

*41 Am Jur 2d, Indians; Native Americans* § 67.

Texts:

Cohen's Handbook of Federal Indian Law (Matthew Bender), ch 17, Natural Resources § 17.03.



LEXSTAT 25 USCS § 2101

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TITLE 25. INDIANS  
CHAPTER 23. DEVELOPMENT OF TRIBAL MINERAL RESOURCES

**Go to the United States Code Service Archive Directory**

*25 USCS § 2105*

§ 2105. Effect of other provisions

Nothing in this Act [25 USCS §§ 2101-2108] shall affect, nor shall any Minerals Agreement approved pursuant to this Act [25 USCS §§ 2101-2108] be subject to or limited by, the Act of May 11, 1938 (52 Stat. 347; 25 U.S.C. 396a et seq.), as amended, any other law authorizing the development or disposition of the mineral resources of an Indian or Indian tribe.

**HISTORY:**

(Dec. 22, 1982, P.L. 97-382, § 6, 96 Stat. 1940.)

**NOTES:**

Code of Federal Regulations:

Bureau of Indian Affairs, Department of the Interior--Leasing of tribal lands for mineral development, 25 CFR 211.1 et seq.

Bureau of Indian Affairs, Department of the Interior--Oil and gas, geothermal, and solid minerals agreements, 25 CFR 225.1 et seq.

Minerals Management Service, Department of the Interior--Royalties, 30 CFR 202.51 et seq.

Minerals Management Service, Department of the Interior--Relief or reduction in royalty rates, 30 CFR 203.0 et seq.

Minerals Management Service, Department of the Interior--Product valuation, 30 CFR 206.10 et seq.

Minerals Management Service, Department of the Interior--Sales agreements or contracts governing the disposal of lease products, 30 CFR 207.1 et seq.

Minerals Management Service, Department of the Interior--Records and files maintenance, 30 CFR 212.50 et seq.

Minerals Management Service, Department of the Interior--Collection of royalties, rentals, bonuses and other monies due the Federal Government, 30 CFR 218.10 et seq.

Minerals Management Service, Department of the Interior--Penalties, 30 CFR 241.50 et seq.

Minerals Management Service, Department of the Interior--Suspensions pending appeal and bonding-royalty management program, 30 CFR 243.1 et seq.

Research Guide:

25 USCS § 2105

Federal Procedure:

11A Fed Proc L Ed, Environmental Protection § 32:816.

Am Jur:

41 Am Jur 2d, Indians; Native Americans § 67.

Texts:

Cohen's Handbook of Federal Indian Law (Matthew Bender), ch 17, Natural Resources § 17.03.



LEXSTAT 25 USCS § 2101

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TITLE 25. INDIANS  
CHAPTER 23. DEVELOPMENT OF TRIBAL MINERAL RESOURCES

**Go to the United States Code Service Archive Directory**

*25 USCS § 2106*

§ 2106. Assistance to tribes or individuals during Minerals Agreement negotiations

In carrying out the obligations of the United States, the Secretary shall ensure that upon the request of an Indian tribe or individual Indian and to the extent of his available resources, such tribe or individual Indian shall have available advice, assistance, and information during the negotiation of a Minerals Agreement. The Secretary may fulfill this responsibility either directly through the use of Federal officials and resources or indirectly by providing financial assistance to the Indian tribe or individual Indian to secure independent assistance.

**HISTORY:**

(Dec. 22, 1982, P.L. 97-382, § 7, 96 Stat. 1940.)

**NOTES:**

Code of Federal Regulations:

Bureau of Indian Affairs, Department of the Interior--Leasing of tribal lands for mineral development, *25 CFR 211.1* et seq.

Bureau of Indian Affairs, Department of the Interior--Oil and gas, geothermal, and solid minerals agreements, *25 CFR 225.1* et seq.

Minerals Management Service, Department of the Interior--Royalties, *30 CFR 202.51* et seq.

Minerals Management Service, Department of the Interior--Relief or reduction in royalty rates, *30 CFR 203.0* et seq.

Minerals Management Service, Department of the Interior--Product valuation, *30 CFR 206.10* et seq.

Minerals Management Service, Department of the Interior--Sales agreements or contracts governing the disposal of lease products, *30 CFR 207.1* et seq.

Minerals Management Service, Department of the Interior--Records and files maintenance, *30 CFR 212.50* et seq.

Minerals Management Service, Department of the Interior--Collection of royalties, rentals, bonuses and other monies due the Federal Government, *30 CFR 218.10* et seq.

Minerals Management Service, Department of the Interior--Penalties, *30 CFR 241.50* et seq.

Minerals Management Service, Department of the Interior--Suspensions pending appeal and bonding-royalty management program, *30 CFR 243.1* et seq.

Research Guide:

25 USCS § 2106

Federal Procedure:

11A Fed Proc L Ed, Environmental Protection § 32:816.

19 Fed Proc L Ed, Indians and Indian Affairs § 46:268.

Am Jur:

*41 Am Jur 2d, Indians; Native Americans § 67.*

Texts:

Cohen's Handbook of Federal Indian Law (Matthew Bender), ch 17, Natural Resources § 17.03.

Interpretive Notes and Decisions:

Advice offered by BIA after proposed joint mineral development agreement was submitted to Secretary of Interior was consistent with Secretary's duty to assist tribe in all stages of transaction under Indian Mineral Development Act (25 USCS §§ 2101-2108). *Quantum Exploration, Inc. v Clark* (1986, CA9 Mont) 780 F2d 1457, 90 OGR 81.



LEXSTAT 25 USCS § 2101

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TITLE 25. INDIANS  
CHAPTER 23. DEVELOPMENT OF TRIBAL MINERAL RESOURCES

**Go to the United States Code Service Archive Directory**

*25 USCS § 2107*

§ 2107. Regulations; consultation with Indian organizations; pending agreements

Within one hundred and eighty days of the date of enactment of this Act [enacted Dec. 22, 1982], the Secretary of the Interior shall promulgate rules and regulations to facilitate implementation of this Act [25 USCS §§ 2101-2108]. The Secretary shall, to the extent practicable, consult with national and regional Indian organizations and tribes with expertise in mineral development both in the initial formulation of rules and regulations and any future revision or amendment of such rules and regulations. Where there is pending before the Secretary for his approval a Minerals Agreement of the type authorized by section 3 of this Act [25 USCS § 2102] which was submitted prior to the enactment of this Act [enacted Dec. 22, 1982], the Secretary shall evaluate and approve or disapprove such agreement based upon section 4 of this Act [25 USCS § 2103], but shall not withhold or delay such approval or disapproval on the grounds that the rules and regulations implementing this Act [25 USCS §§ 2101-2108] have not been promulgated.

**HISTORY:**

(Dec. 22, 1982, P.L. 97-382, § 8, 96 Stat. 1940.)

**NOTES:**

Code of Federal Regulations:

Bureau of Indian Affairs, Department of the Interior--Leasing of tribal lands for mineral development, *25 CFR 211.1* et seq.

Bureau of Indian Affairs, Department of the Interior--Oil and gas, geothermal, and solid minerals agreements, *25 CFR 225.1* et seq.

Minerals Management Service, Department of the Interior--Royalties, *30 CFR 202.51* et seq.

Minerals Management Service, Department of the Interior--Relief or reduction in royalty rates, *30 CFR 203.0* et seq.

Minerals Management Service, Department of the Interior--Product valuation, *30 CFR 206.10* et seq.

Minerals Management Service, Department of the Interior--Sales agreements or contracts governing the disposal of lease products, *30 CFR 207.1* et seq.

Minerals Management Service, Department of the Interior--Forms and reports, *30 CFR 210.01* et seq.

Minerals Management Service, Department of the Interior--Records and files maintenance, *30 CFR 212.50* et seq.

Minerals Management Service, Department of the Interior--Collection of royalties, rentals, bonuses and other monies due the Federal Government, *30 CFR 218.10* et seq.

Minerals Management Service, Department of the Interior--Penalties, *30 CFR 241.50* et seq.

25 USCS § 2107

Minerals Management Service, Department of the Interior--Suspensions pending appeal and bonding-royalty management program, *30 CFR 243.1* et seq.

Bureau of Land Management, Department of the Interior--Geothermal resources leasing, *43 CFR 3200.1* et seq.

Bureau of Land Management, Department of the Interior--Oil shale exploration licenses, *43 CFR 3910.21* et seq.

Bureau of Land Management, Department of the Interior--Management of oil shale exploration and leases, *43 CFR 3930.10* et seq.

Related Statutes & Rules:

This section is referred to in *25 USCS § 2104*.

Research Guide:

Federal Procedure:

11A Fed Proc L Ed, Environmental Protection § 32:816.

Am Jur:

*41 Am Jur 2d, Indians; Native Americans § 67.*



LEXSTAT 25 USCS § 2101

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TITLE 25. INDIANS  
CHAPTER 23. DEVELOPMENT OF TRIBAL MINERAL RESOURCES

**Go to the United States Code Service Archive Directory**

*25 USCS § 2108*

§ 2108. Tribal right to develop mineral resources

Nothing in this Act [25 USCS §§ 2101-2108] shall impair any right of an Indian tribe organized under section 16 or 17 of the Act of June 18, 1934 (48 Stat. 987), as amended [25 USCS § 476 or 477], to develop their mineral resources as may be provided in any constitution or charter adopted by such tribe pursuant to that Act.

**HISTORY:**

(Dec. 22, 1982, P.L. 97-382, § 9, 96 Stat. 1940.)

**HISTORY; ANCILLARY LAWS AND DIRECTIVES**

**References in text:**

"That Act", referred to in this section, is Act June 18, 1934, ch 576, 48 Stat. 984, which appears generally as 25 USCS §§ 461 et seq. For full classification of such Act, consult USCS Tables volumes.

**NOTES:**

**Code of Federal Regulations:**

- Minerals Management Service, Department of the Interior--Royalties, 30 CFR 202.51 et seq.
- Minerals Management Service, Department of the Interior--Relief or reduction in royalty rates, 30 CFR 203.0 et seq.
- Minerals Management Service, Department of the Interior--Product valuation, 30 CFR 206.10 et seq.
- Minerals Management Service, Department of the Interior--Sales agreements or contracts governing the disposal of lease products, 30 CFR 207.1 et seq.
- Minerals Management Service, Department of the Interior--Records and files maintenance, 30 CFR 212.50 et seq.
- Minerals Management Service, Department of the Interior--Collection of royalties, rentals, bonuses and other monies due the Federal Government, 30 CFR 218.10 et seq.
- Minerals Management Service, Department of the Interior--Penalties, 30 CFR 241.50 et seq.
- Minerals Management Service, Department of the Interior--Suspensions pending appeal and bonding-royalty management program, 30 CFR 243.1 et seq.
- Bureau of Land Management, Department of the Interior--Onshore oil and gas operations, 43 CFR 3160.0-1 et seq.

25 USCS § 2108

Bureau of Land Management, Department of the Interior--Leasing of solid minerals other than coal and oil shale, 43 *CFR* 3501.1 et seq.

Bureau of Land Management, Department of the Interior--Solid minerals (other than coal) exploration and mining operations, 43 *CFR* 3590.0-1 et seq.

Research Guide:

Federal Procedure:

11A Fed Proc L Ed, Environmental Protection § 32:816.

Am Jur:

41 *Am Jur* 2d, *Indians; Native Americans* § 67.



LEXSTAT 25 USCS 3501

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TITLE 25. INDIANS  
CHAPTER 37. INDIAN ENERGY

**Go to the United States Code Service Archive Directory**

*25 USCS § 3501*

§ 3501. Definitions

In this *title* [25 USCS §§ 3501 et seq.]:

(1) The term "Director" means the Director of the Office of Indian Energy Policy and Programs, Department of Energy.

(2) The term "Indian land" means--

(A) any land located within the boundaries of an Indian reservation, pueblo, or rancharia;

(B) any land not located within the boundaries of an Indian reservation, pueblo, or rancharia, the title to which is held--

(i) in trust by the United States for the benefit of an Indian tribe or an individual Indian;

(ii) by an Indian tribe or an individual Indian, subject to restriction against alienation under laws of the United States; or

(iii) by a dependent Indian community; and

(C) land that is owned by an Indian tribe and was conveyed by the United States to a Native Corporation pursuant to the Alaska Native Claims Settlement Act (43 U.S.C. 1601 et seq.), or that was conveyed by the United States to a Native Corporation in exchange for such land.

(3) The term "Indian reservation" includes--

(A) an Indian reservation in existence in any State or States as of the date of enactment of this paragraph [enacted Aug. 8, 2005];

(B) a public domain Indian allotment; and

(C) a dependent Indian community located within the borders of the United States, regardless of whether the community is located--

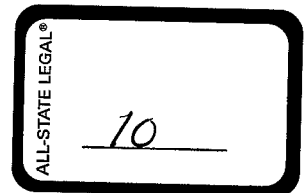
(i) on original or acquired territory of the community; or

(ii) within or outside the boundaries of any State or States.

(4) (A) The term "Indian tribe" has the meaning given the term in section 4 of the Indian Self-Determination and Education Assistance Act (25 U.S.C. 450b).

(B) For the purpose of paragraph (12) and sections 2603(b)(1)(C) and 2604 [25 USCS §§ 3503(b)(1)(C) and 3504], the term "Indian tribe" does not include any Native Corporation.

(5) The term "integration of energy resources" means any project or activity that promotes the location and operation of a facility (including any pipeline, gathering system, transportation system or facility, or electric transmission or distribution facility) on or near Indian land to process, refine, generate electricity from, or otherwise develop energy resources on, Indian land.



## 25 USCS § 3501

(6) The term "Native Corporation" has the meaning given the term in section 3 of the Alaska Native Claims Settlement Act (43 U.S.C. 1602).

(7) The term "organization" means a partnership, joint venture, limited liability company, or other unincorporated association or entity that is established to develop Indian energy resources.

(8) The term "Program" means the Indian energy resource development program established under section 2602(a) [25 USCS § 3502(a)].

(9) The term "Secretary" means the Secretary of the Interior.

(10) The term "sequestration" means the long-term separation, isolation, or removal of greenhouse gases from the atmosphere, including through a biological or geologic method such as reforestation or an underground reservoir.

(11) The term "tribal energy resource development organization" means an organization of two or more entities, at least one of which is an Indian tribe, that has the written consent of the governing bodies of all Indian tribes participating in the organization to apply for a grant, loan, or other assistance under section 2602 [25 USCS § 3502].

(12) The term "tribal land" means any land or interests in land owned by any Indian tribe, title to which is held in trust by the United States, or is subject to a restriction against alienation under laws of the United States.

**HISTORY:**

(Oct. 24, 1992, P.L. 102-486, Title XXVI, § 2601, as added Aug. 8, 2005, P.L. 109-58, Title V, § 503(a), 119 Stat. 764.)

**HISTORY; ANCILLARY LAWS AND DIRECTIVES****Explanatory notes:**

A prior § 3501 (Act Oct. 24, 1992, P.L. 102-486, Title XXVI, § 2601, 106 Stat. 3113), relating to Indian energy resources, was replaced in the general revision of Title XXVI of Act Oct. 24, 1992, P.L. 102-486, by § 503(a) of Act Aug. 8, 2005, P.L. 109-58. Such section provided for definitions.

**Other provisions:**

**Consultation with Indian tribes.** Act Aug. 8, 2005, P.L. 109-58, Title V, § 504, 119 Stat. 778, provides: "In carrying out this title and the amendments made by this title [generally amending 25 USCS §§ 3501 et seq.; for full classification, consult USCS Tables volumes], the Secretary and the Secretary of the Interior shall, as appropriate and to the maximum extent practicable, involve and consult with Indian tribes."

**NOTES:****Code of Federal Regulations:**

Bureau of Indian Affairs, Department of the Interior--Tribal energy resource agreements under the Indian Tribal Energy Development and Self-Determination Act, 25 CFR 224.10 et seq.

**Research Guide:****Texts:**

Cohen's Handbook of Federal Indian Law (Matthew Bender), ch 4, Indian Tribal Governments § 4.07.

Cohen's Handbook of Federal Indian Law (Matthew Bender), ch 17, Natural Resources § 17.03.

3 Energy Law & Transactions (Matthew Bender), ch 59, Energy Policy Act of 2005 § 59.05.



LEXSTAT 25 USCS 3501

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TITLE 25. INDIANS  
CHAPTER 37. INDIAN ENERGY

Go to the United States Code Service Archive Directory

25 USCS § 3502

§ 3502. Indian tribal energy resource development

(a) Department of the Interior program.

(1) To assist Indian tribes in the development of energy resources and further the goal of Indian self-determination, the Secretary shall establish and implement an Indian energy resource development program to assist consenting Indian tribes and tribal energy resource development organizations in achieving the purposes of this *title* [25 USCS §§ 3501 et seq.].

(2) In carrying out the Program, the Secretary shall--

(A) provide development grants to Indian tribes and tribal energy resource development organizations for use in developing or obtaining the managerial and technical capacity needed to develop energy resources on Indian land, and to properly account for resulting energy production and revenues;

(B) provide grants to Indian tribes and tribal energy resource development organizations for use in carrying out projects to promote the integration of energy resources, and to process, use, or develop those energy resources, on Indian land;

(C) provide low-interest loans to Indian tribes and tribal energy resource development organizations for use in the promotion of energy resource development on Indian land and integration of energy resources; and

(D) provide grants and technical assistance to an appropriate tribal environmental organization, as determined by the Secretary, that represents multiple Indian tribes to establish a national resource center to develop tribal capacity to establish and carry out tribal environmental programs in support of energy-related programs and activities under this *title* [25 USCS §§ 3501 et seq.], including--

(i) training programs for tribal environmental officials, program managers, and other governmental representatives;

(ii) the development of model environmental policies and tribal laws, including tribal environmental review codes, and the creation and maintenance of a clearinghouse of best environmental management practices; and

(iii) recommended standards for reviewing the implementation of tribal environmental laws and policies within tribal judicial or other tribal appeals systems.

(3) There are authorized to be appropriated to carry out this subsection such sums as are necessary for each of fiscal years 2006 through 2016.

(b) Department of Energy Indian energy education planning and management assistance program.

(1) The Director shall establish programs to assist consenting Indian tribes in meeting energy education, research and development, planning, and management needs.

## 25 USCS § 3502

(2) In carrying out this subsection, the Director may provide grants, on a competitive basis, to an Indian tribe or tribal energy resource development organization for use in carrying out--

(A) energy, energy efficiency, and energy conservation programs;

(B) studies and other activities supporting tribal acquisitions of energy supplies, services, and facilities, including the creation of tribal utilities to assist in securing electricity to promote electrification of homes and businesses on Indian land;

(C) planning, construction, development, operation, maintenance, and improvement of tribal electrical generation, transmission, and distribution facilities located on Indian land; and

(D) development, construction, and interconnection of electric power transmission facilities located on Indian land with other electric transmission facilities.

(3) (A) The Director shall develop a program to support and implement research projects that provide Indian tribes with opportunities to participate in carbon sequestration practices on Indian land, including--

(i) geologic sequestration;

(ii) forest sequestration;

(iii) agricultural sequestration; and

(iv) any other sequestration opportunities the Director considers to be appropriate.

(B) The activities carried out under subparagraph (A) shall be--

(i) coordinated with other carbon sequestration research and development programs conducted by the Secretary of Energy;

(ii) conducted to determine methods consistent with existing standardized measurement protocols to account and report the quantity of carbon dioxide or other greenhouse gases sequestered in projects that may be implemented on Indian land; and

(iii) reviewed periodically to collect and distribute to Indian tribes information on carbon sequestration practices that will increase the sequestration of carbon without threatening the social and economic well-being of Indian tribes.

(4) (A) The Director, in consultation with Indian tribes, may develop a formula for providing grants under this subsection.

(B) In providing a grant under this subsection, the Director shall give priority to any application received from an Indian tribe with inadequate electric service (as determined by the Director).

(C) In providing a grant under this subsection for an activity to provide, or expand the provision of, electricity on Indian land, the Director shall encourage cooperative arrangements between Indian tribes and utilities that provide service to Indian tribes, as the Director determines to be appropriate.

(5) The Secretary of Energy may issue such regulations as the Secretary determines to be necessary to carry out this subsection.

(6) There is authorized to be appropriated to carry out this subsection \$ 20,000,000 for each of fiscal years 2006 through 2016.

(c) Department of Energy loan guarantee program.

(1) Subject to paragraphs (2) and (4), the Secretary of Energy may provide loan guarantees (as defined in section 502 of the Federal Credit Reform Act of 1990 (2 U.S.C. 661a)) for an amount equal to not more than 90 percent of the unpaid principal and interest due on any loan made to an Indian tribe for energy development.

(2) In providing a loan guarantee under this subsection for an activity to provide, or expand the provision of, electricity on Indian land, the Secretary of Energy shall encourage cooperative arrangements between Indian tribes and utilities that provide service to Indian tribes, as the Secretary determines to be appropriate.

(3) A loan guarantee under this subsection shall be made by--

(A) a financial institution subject to examination by the Secretary of Energy; or

(B) an Indian tribe, from funds of the Indian tribe.

(4) The aggregate outstanding amount guaranteed by the Secretary of Energy at any time under this subsection shall not exceed \$ 2,000,000,000.

(5) The Secretary of Energy may issue such regulations as the Secretary of Energy determines are necessary to carry out this subsection.

(6) There are authorized to be appropriated such sums as are necessary to carry out this subsection, to remain available until expended.

(7) Not later than 1 year after the date of enactment of this section [enacted Aug. 8, 2005], the Secretary of Energy shall submit to Congress a report on the financing requirements of Indian tribes for energy development on Indian land.

25 USCS § 3502

(d) Preference.

(1) In purchasing electricity or any other energy product or byproduct, a Federal agency or department may give preference to an energy and resource production enterprise, partnership, consortium, corporation, or other type of business organization the majority of the interest in which is owned and controlled by 1 or more Indian tribes.

(2) In carrying out this subsection, a Federal agency or department shall not--

(A) pay more than the prevailing market price for an energy product or byproduct; or

(B) obtain less than prevailing market terms and conditions.

**HISTORY:**

(Oct. 24, 1992, P.L. 102-486, Title XXVI, § 2602, as added Aug. 8, 2005, P.L. 109-58, Title V, § 503(a), 119 Stat. 765.)

**HISTORY; ANCILLARY LAWS AND DIRECTIVES**

**Explanatory notes:**

A prior § 3502 (Act Oct. 24, 1992, P.L. 102-486, Title XXVI, § 2602, 106 Stat. 3113), relating to Indian energy resources, was replaced in the general revision of Title XXVI of Act Oct. 24, 1992, P.L. 102-486, by § 503(a) of Act Aug. 8, 2005, P.L. 109-58. Such section provided for tribal consultation.

**NOTES:**

**Code of Federal Regulations:**

Bureau of Indian Affairs, Department of the Interior--Tribal energy resource agreements under the Indian Tribal Energy Development and Self-Determination Act, 25 *CFR* 224.10 et seq.

**Research Guide:**

**Texts:**

Cohen's Handbook of Federal Indian Law (Matthew Bender), ch 17, Natural Resources § 17.03.



LEXSTAT 25 USCS 3501

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TITLE 25. INDIANS  
CHAPTER 37. INDIAN ENERGY

**Go to the United States Code Service Archive Directory**

*25 USCS § 3503*

§ 3503. Indian tribal energy resource regulation

(a) Grants. The Secretary may provide to Indian tribes, on an annual basis, grants for use in accordance with subsection (b).

(b) Use of funds. Funds from a grant provided under this section may be used--

(1) (A) by an Indian tribe for the development of a tribal energy resource inventory or tribal energy resource on Indian land;

(B) by an Indian tribe for the development of a feasibility study or other report necessary to the development of energy resources on Indian land;

(C) by an Indian tribe (other than an Indian Tribe in the State of Alaska, except the Metlakatla Indian Community) for--

(i) the development and enforcement of tribal laws (including regulations) relating to tribal energy resource development; and

(ii) the development of technical infrastructure to protect the environment under applicable law; or

(D) by a Native Corporation for the development and implementation of corporate policies and the development of technical infrastructure to protect the environment under applicable law; and

(2) by an Indian tribe for the training of employees that--

(A) are engaged in the development of energy resources on Indian land; or

(B) are responsible for protecting the environment.

(c) Other assistance.

(1) In carrying out the obligations of the United States under this *title* [25 USCS §§ 3501 et seq.], the Secretary shall ensure, to the maximum extent practicable and to the extent of available resources, that on the request of an Indian tribe, the Indian tribe shall have available scientific and technical information and expertise, for use in the regulation, development, and management of energy resources of the Indian tribe on Indian land.

(2) The Secretary may carry out paragraph (1)--

(A) directly, through the use of Federal officials; or

(B) indirectly, by providing financial assistance to an Indian tribe to secure independent assistance.

**HISTORY:**

(Oct. 24, 1992, P.L. 102-486, Title XXVI, § 2603, as added Aug. 8, 2005, P.L. 109-58, Title V, § 503(a), 119 Stat. 768.)

25 USCS § 3503

**HISTORY; ANCILLARY LAWS AND DIRECTIVES**

Explanatory notes:

A prior § 3503 (Act Oct. 24, 1992, P.L. 102-486, Title XXVI, § 2603, 106 Stat. 3114; Nov. 13, 1998, P.L. 105-388, § 10, 112 Stat. 3484), relating to Indian energy resources, was replaced in the general revision of Title XXVI of Act Oct. 24, 1992, P.L. 102-486, by § 503(a) of Act Aug. 8, 2005, P.L. 109-58. Such section provided for the promotion of energy resource development and energy vertical integration on Indian reservations. For similar provisions, see *25 USCS* § 3502.

**NOTES:**

Code of Federal Regulations:

Bureau of Indian Affairs, Department of the Interior--Tribal energy resource agreements under the Indian Tribal Energy Development and Self-Determination Act, *25 CFR 224.10* et seq.

Research Guide:

Texts:

Cohen's Handbook of Federal Indian Law (Matthew Bender), ch 17, Natural Resources § 17.03.



LEXSTAT 25 USCS 3501

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TITLE 25. INDIANS  
CHAPTER 37. INDIAN ENERGY

**Go to the United States Code Service Archive Directory**

*25 USCS § 3504*

§ 3504. Leases, business agreements, and rights-of-way involving energy development or transmission

(a) Leases and business agreements. In accordance with this section--

(1) an Indian tribe may, at the discretion of the Indian tribe, enter into a lease or business agreement for the purpose of energy resource development on tribal land, including a lease or business agreement for--

(A) exploration for, extraction of, processing of, or other development of the energy mineral resources of the Indian tribe located on tribal land; or

(B) construction or operation of--

(i) an electric generation, transmission, or distribution facility located on tribal land; or

(ii) a facility to process or refine energy resources developed on tribal land; and

(2) a lease or business agreement described in paragraph (1) shall not require review by or the approval of the Secretary under section 2103 of the Revised Statutes (25 U.S.C. 81), or any other provision of law, if--

(A) the lease or business agreement is executed pursuant to a tribal energy resource agreement approved by the Secretary under subsection (e);

(B) the term of the lease or business agreement does not exceed--

(i) 30 years; or

(ii) in the case of a lease for the production of oil resources, gas resources, or both, 10 years and as long thereafter as oil or gas is produced in paying quantities; and

(C) the Indian tribe has entered into a tribal energy resource agreement with the Secretary, as described in subsection (e), relating to the development of energy resources on tribal land (including the periodic review and evaluation of the activities of the Indian tribe under the agreement, to be conducted pursuant to subsection (e)(2)(D)(i)).

(b) Rights-of-way for pipelines or electric transmission or distribution lines. An Indian tribe may grant a right-of-way over tribal land for a pipeline or an electric transmission or distribution line without review or approval by the Secretary if--

(1) the right-of-way is executed in accordance with a tribal energy resource agreement approved by the Secretary under subsection (e);

(2) the term of the right-of-way does not exceed 30 years;

(3) the pipeline or electric transmission or distribution line serves--

(A) an electric generation, transmission, or distribution facility located on tribal land; or

(B) a facility located on tribal land that processes or refines energy resources developed on tribal land; and

## 25 USCS § 3504

(4) the Indian tribe has entered into a tribal energy resource agreement with the Secretary, as described in subsection (e), relating to the development of energy resources on tribal land (including the periodic review and evaluation of the activities of the Indian tribe under an agreement described in subparagraphs (D) and (E) of subsection (e)(2)).

(c) Renewals. A lease or business agreement entered into, or a right-of-way granted, by an Indian tribe under this section may be renewed at the discretion of the Indian tribe in accordance with this section.

(d) Validity. No lease, business agreement, or right-of-way relating to the development of tribal energy resources under this section shall be valid unless the lease, business agreement, or right-of-way is authorized by a tribal energy resource agreement approved by the Secretary under subsection (e)(2).

(e) Tribal energy resource agreements.

(1) On the date on which regulations are promulgated under paragraph (8), an Indian tribe may submit to the Secretary for approval a tribal energy resource agreement governing leases, business agreements, and rights-of-way under this section.

(2) (A) Not later than 270 days after the date on which the Secretary receives a tribal energy resource agreement from an Indian tribe under paragraph (1), or not later than 60 days after the Secretary receives a revised tribal energy resource agreement from an Indian tribe under paragraph (4)(C) (or a later date, as agreed to by the Secretary and the Indian tribe), the Secretary shall approve or disapprove the tribal energy resource agreement.

(B) The Secretary shall approve a tribal energy resource agreement submitted under paragraph (1) if--

(i) the Secretary determines that the Indian tribe has demonstrated that the Indian tribe has sufficient capacity to regulate the development of energy resources of the Indian tribe;

(ii) the tribal energy resource agreement includes provisions required under subparagraph (D); and

(iii) the tribal energy resource agreement includes provisions that, with respect to a lease, business agreement, or right-of-way under this section--

(I) ensure the acquisition of necessary information from the applicant for the lease, business agreement, or right-of-way;

(II) address the term of the lease or business agreement or the term of conveyance of the right-of-way;

(III) address amendments and renewals;

(IV) address the economic return to the Indian tribe under leases, business agreements, and rights-of-way;

(V) address technical or other relevant requirements;

(VI) establish requirements for environmental review in accordance with subparagraph (C);

(VII) ensure compliance with all applicable environmental laws, including a requirement that each lease, business agreement, and right-of-way state that the lessee, operator, or right-of-way grantee shall comply with all such laws;

(VIII) identify final approval authority;

(IX) provide for public notification of final approvals;

(X) establish a process for consultation with any affected States regarding off-reservation impacts, if any, identified under subparagraph (C)(i);

(XI) describe the remedies for breach of the lease, business agreement, or right-of-way;

(XII) require each lease, business agreement, and right-of-way to include a statement that, if any of its provisions violates an express term or requirement of the tribal energy resource agreement pursuant to which the lease, business agreement, or right-of-way was executed--

(aa) the provision shall be null and void; and

(bb) if the Secretary determines the provision to be material, the Secretary may suspend or rescind the lease, business agreement, or right-of-way or take other appropriate action that the Secretary determines to be in the best interest of the Indian tribe;

(XIII) require each lease, business agreement, and right-of-way to provide that it will become effective on the date on which a copy of the executed lease, business agreement, or right-of-way is delivered to the Secretary in accordance with regulations promulgated under paragraph (8);

(XIV) include citations to tribal laws, regulations, or procedures, if any, that set out tribal remedies that must be exhausted before a petition may be submitted to the Secretary under paragraph (7)(B);

(XV) specify the financial assistance, if any, to be provided by the Secretary to the Indian tribe to assist in implementation of the tribal energy resource agreement, including environmental review of individual projects; and

(XVI) in accordance with the regulations promulgated by the Secretary under paragraph (8), require that the Indian tribe, as soon as practicable after receipt of a notice by the Indian tribe, give written notice to the Secretary of--

## 25 USCS § 3504

(aa) any breach or other violation by another party of any provision in a lease, business agreement, or right-of-way entered into under the tribal energy resource agreement; and

(bb) any activity or occurrence under a lease, business agreement, or right-of-way that constitutes a violation of Federal or tribal environmental laws.

(C) Tribal energy resource agreements submitted under paragraph (1) shall establish, and include provisions to ensure compliance with, an environmental review process that, with respect to a lease, business agreement, or right-of-way under this section, provides for, at a minimum--

(i) the identification and evaluation of all significant environmental effects (as compared to a no-action alternative), including effects on cultural resources;

(ii) the identification of proposed mitigation measures, if any, and incorporation of appropriate mitigation measures into the lease, business agreement, or right-of-way;

(iii) a process for ensuring that--

(I) the public is informed of, and has an opportunity to comment on, the environmental impacts of the proposed action; and

(II) responses to relevant and substantive comments are provided, before tribal approval of the lease, business agreement, or right-of-way;

(iv) sufficient administrative support and technical capability to carry out the environmental review process; and

(v) oversight by the Indian tribe of energy development activities by any other party under any lease, business agreement, or right-of-way entered into pursuant to the tribal energy resource agreement, to determine whether the activities are in compliance with the tribal energy resource agreement and applicable Federal environmental laws.

(D) A tribal energy resource agreement between the Secretary and an Indian tribe under this subsection shall include--

(i) provisions requiring the Secretary to conduct a periodic review and evaluation to monitor the performance of the activities of the Indian tribe associated with the development of energy resources under the tribal energy resource agreement; and

(ii) if a periodic review and evaluation, or an investigation, by the Secretary of any breach or violation described in a notice provided by the Indian tribe to the Secretary in accordance with subparagraph (B)(iii)(XVI), results in a finding by the Secretary of imminent jeopardy to a physical trust asset arising from a violation of the tribal energy resource agreement or applicable Federal laws, provisions authorizing the Secretary to take actions determined by the Secretary to be necessary to protect the asset, including reassumption of responsibility for activities associated with the development of energy resources on tribal land until the violation and any condition that caused the jeopardy are corrected.

(E) Periodic review and evaluation under subparagraph (D) shall be conducted on an annual basis, except that, after the third annual review and evaluation, the Secretary and the Indian tribe may mutually agree to amend the tribal energy resource agreement to authorize the review and evaluation under subparagraph (D) to be conducted once every 2 years.

(3) The Secretary shall provide notice and opportunity for public comment on tribal energy resource agreements submitted for approval under paragraph (1). The Secretary's review of a tribal energy resource agreement shall be limited to activities specified by the provisions of the tribal energy resource agreement.

(4) If the Secretary disapproves a tribal energy resource agreement submitted by an Indian tribe under paragraph (1), the Secretary shall, not later than 10 days after the date of disapproval--

(A) notify the Indian tribe in writing of the basis for the disapproval;

(B) identify what changes or other actions are required to address the concerns of the Secretary; and

(C) provide the Indian tribe with an opportunity to revise and resubmit the tribal energy resource agreement.

(5) If an Indian tribe executes a lease or business agreement, or grants a right-of-way, in accordance with a tribal energy resource agreement approved under this subsection, the Indian tribe shall, in accordance with the process and requirements under regulations promulgated under paragraph (8), provide to the Secretary--

(A) a copy of the lease, business agreement, or right-of-way document (including all amendments to and renewals of the document); and

(B) in the case of a tribal energy resource agreement or a lease, business agreement, or right-of-way that permits payments to be made directly to the Indian tribe, information and documentation of those payments sufficient to enable the Secretary to discharge the trust responsibility of the United States to enforce the terms of, and protect the rights of the Indian tribe under, the lease, business agreement, or right-of-way.

(6) (A) In carrying out this section, the Secretary shall--

(i) act in accordance with the trust responsibility of the United States relating to mineral and other trust resources; and

(ii) act in good faith and in the best interests of the Indian tribes.

## 25 USCS § 3504

(B) Subject to the provisions of subsections (a)(2), (b), and (c) waiving the requirement of Secretarial approval of leases, business agreements, and rights-of-way executed pursuant to tribal energy resource agreements approved under this section, and the provisions of subparagraph (D), nothing in this section shall absolve the United States from any responsibility to Indians or Indian tribes, including, but not limited to, those which derive from the trust relationship or from any treaties, statutes, and other laws of the United States, Executive orders, or agreements between the United States and any Indian tribe.

(C) The Secretary shall continue to fulfill the trust obligation of the United States to ensure that the rights and interests of an Indian tribe are protected if--

(i) any other party to a lease, business agreement, or right-of-way violates any applicable Federal law or the terms of any lease, business agreement, or right-of-way under this section; or

(ii) any provision in a lease, business agreement, or right-of-way violates the tribal energy resource agreement pursuant to which the lease, business agreement, or right-of-way was executed.

(D) (i) In this subparagraph, the term "negotiated term" means any term or provision that is negotiated by an Indian tribe and any other party to a lease, business agreement, or right-of-way entered into pursuant to an approved tribal energy resource agreement.

(ii) Notwithstanding subparagraph (B), the United States shall not be liable to any party (including any Indian tribe) for any negotiated term of, or any loss resulting from the negotiated terms of, a lease, business agreement, or right-of-way executed pursuant to and in accordance with a tribal energy resource agreement approved by the Secretary under paragraph (2).

(7) (A) In this paragraph, the term "interested party" means any person (including an entity) that has demonstrated that an interest of the person has sustained, or will sustain, an adverse environmental impact as a result of the failure of an Indian tribe to comply with a tribal energy resource agreement of the Indian tribe approved by the Secretary under paragraph (2).

(B) After exhaustion of any tribal remedy, and in accordance with regulations promulgated by the Secretary under paragraph (8), an interested party may submit to the Secretary a petition to review the compliance by an Indian tribe with a tribal energy resource agreement of the Indian tribe approved by the Secretary under paragraph (2).

(C) (i) Not later than 20 days after the date on which the Secretary receives a petition under subparagraph (B), the Secretary shall--

(I) provide to the Indian tribe a copy of the petition; and

(II) consult with the Indian tribe regarding any noncompliance alleged in the petition.

(ii) Not later than 45 days after the date on which a consultation under clause (i)(II) takes place, the Indian tribe shall respond to any claim made in a petition under subparagraph (B).

(iii) The Secretary shall act in accordance with subparagraphs (D) and (E) only if the Indian tribe--

(I) denies, or fails to respond to, each claim made in the petition within the period described in clause (ii); or

(II) fails, refuses, or is unable to cure or otherwise resolve each claim made in the petition within a reasonable period, as determined by the Secretary, after the expiration of the period described in clause (ii).

(D) (i) Not later than 120 days after the date on which the Secretary receives a petition under subparagraph (B), the Secretary shall determine whether the Indian tribe is not in compliance with the tribal energy resource agreement.

(ii) The Secretary may adopt procedures under paragraph (8) authorizing an extension of time, not to exceed 120 days, for making the determination under clause (i) in any case in which the Secretary determines that additional time is necessary to evaluate the allegations of the petition.

(iii) Subject to subparagraph (E), if the Secretary determines that the Indian tribe is not in compliance with the tribal energy resource agreement, the Secretary shall take such action as the Secretary determines to be necessary to ensure compliance with the tribal energy resource agreement, including--

(I) temporarily suspending any activity under a lease, business agreement, or right-of-way under this section until the Indian tribe is in compliance with the approved tribal energy resource agreement; or

(II) rescinding approval of all or part of the tribal energy resource agreement, and if all of the agreement is rescinded, reassuming the responsibility for approval of any future leases, business agreements, or rights-of-way described in subsection (a) or (b).

(E) Before taking an action described in subparagraph (D)(iii), the Secretary shall--

(i) make a written determination that describes the manner in which the tribal energy resource agreement has been violated;

(ii) provide the Indian tribe with a written notice of the violations together with the written determination; and

(iii) before taking any action described in subparagraph (D)(iii) or seeking any other remedy, provide the Indian tribe with a hearing and a reasonable opportunity to attain compliance with the tribal energy resource agreement.

## 25 USCS § 3504

(F) An Indian tribe described in subparagraph (E) shall retain all rights to appeal under any regulation promulgated by the Secretary.

(8) Not later than 1 year after the date of enactment of the Energy Policy Act of 2005 [enacted Aug. 8, 2005], the Secretary shall promulgate regulations that implement this subsection, including--

(A) criteria to be used in determining the capacity of an Indian tribe under paragraph (2)(B)(i), including the experience of the Indian tribe in managing natural resources and financial and administrative resources available for use by the Indian tribe in implementing the approved tribal energy resource agreement of the Indian tribe;

(B) a process and requirements in accordance with which an Indian tribe may--

(i) voluntarily rescind a tribal energy resource agreement approved by the Secretary under this subsection; and

(ii) return to the Secretary the responsibility to approve any future lease, business agreement, or right-of-way under this subsection;

(C) provisions establishing the scope of, and procedures for, the periodic review and evaluation described in subparagraphs (D) and (E) of paragraph (2), including provisions for review of transactions, reports, site inspections, and any other review activities the Secretary determines to be appropriate; and

(D) provisions describing final agency actions after exhaustion of administrative appeals from determinations of the Secretary under paragraph (7).

(f) No effect on other law. Nothing in this section affects the application of--

(1) any Federal environmental law;

(2) the Surface Mining Control and Reclamation Act of 1977 (30 U.S.C. 1201 et seq.); or

(3) except as otherwise provided in this *title* [25 USCS §§ 3501 et seq.], the Indian Mineral Development Act of 1982 (25 U.S.C. 2101 et seq.).

(g) Authorization of appropriations. There are authorized to be appropriated to the Secretary such sums as are necessary for each of fiscal years 2006 through 2016 to carry out this section and to make grants or provide other appropriate assistance to Indian tribes to assist the Indian tribes in developing and implementing tribal energy resource agreements in accordance with this section.

**HISTORY:**

(Oct. 24, 1992, P.L. 102-486, Title XXVI, § 2604, as added Aug. 8, 2005, P.L. 109-58, Title V, § 503(a), 119 Stat. 769.)

**HISTORY; ANCILLARY LAWS AND DIRECTIVES****Explanatory notes:**

A prior § 3504 (Act Oct. 24, 1992, P.L. 102-486, Title XXVI, § 2604, 106 Stat. 3114), relating to Indian energy resources, was replaced in the general revision of Title XXVI of Act Oct. 24, 1992, P.L. 102-486, by § 503(a) of Act Aug. 8, 2005, P.L. 109-58. Such section provided for Indian energy resource regulation. For similar provisions, see 25 USCS § 3503.

**NOTES:****Code of Federal Regulations:**

Bureau of Indian Affairs, Department of the Interior--Tribal energy resource agreements under the Indian Tribal Energy Development and Self-Determination Act, 25 CFR 224.10 et seq.

**Research Guide:****Texts:**

Cohen's Handbook of Federal Indian Law (Matthew Bender), ch 17, Natural Resources § 17.03.



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TITLE 25. INDIANS  
CHAPTER 37. INDIAN ENERGY

**Go to the United States Code Service Archive Directory**

*25 USCS § 3505*

§ 3505. Federal power marketing administrations

(a) Definitions. In this section:

(1) The term "Administrator" means the Administrator of the Bonneville Power Administration and the Administrator of the Western Area Power Administration.

(2) The term "power marketing administration" means--

- (A) the Bonneville Power Administration;
- (B) the Western Area Power Administration; and

(C) any other power administration the power allocation of which is used by or for the benefit of an Indian tribe located in the service area of the administration.

(b) Encouragement of Indian tribal energy development. Each Administrator shall encourage Indian tribal energy development by taking such actions as the Administrators determine to be appropriate, including administration of programs of the power marketing administration, in accordance with this section.

(c) Action by administrators. In carrying out this section, in accordance with laws in existence on the date of enactment of the Energy Policy Act of 2005 [enacted Aug. 8, 2005]--

(1) each Administrator shall consider the unique relationship that exists between the United States and Indian tribes;

(2) power allocations from the Western Area Power Administration to Indian tribes may be used to meet firming and reserve needs of Indian-owned energy projects on Indian land;

(3) the Administrator of the Western Area Power Administration may purchase non-federally generated power from Indian tribes to meet the firming and reserve requirements of the Western Area Power Administration; and

(4) each Administrator shall not--

- (A) pay more than the prevailing market price for an energy product; or
- (B) obtain less than prevailing market terms and conditions.

(d) Assistance for transmission system use.

(1) An Administrator may provide technical assistance to Indian tribes seeking to use the high-voltage transmission system for delivery of electric power.

(2) The costs of technical assistance provided under paragraph (1) shall be funded--

- (A) by the Secretary of Energy using nonreimbursable funds appropriated for that purpose; or
- (B) by any appropriate Indian tribe.

25 USCS § 3505

(e) Power allocation study. Not later than 2 years after the date of enactment of the Energy Policy Act of 2005 [enacted Aug. 8, 2005], the Secretary of Energy shall submit to Congress a report that--

(1) describes the use by Indian tribes of Federal power allocations of the power marketing administration (or power sold by the Southwestern Power Administration) to or for the benefit of Indian tribes in a service area of the power marketing administration; and

(2) identifies--

(A) the quantity of power allocated to, or used for the benefit of, Indian tribes by the Western Area Power Administration;

(B) the quantity of power sold to Indian tribes by any other power marketing administration; and

(C) barriers that impede tribal access to and use of Federal power, including an assessment of opportunities to remove those barriers and improve the ability of power marketing administrations to deliver Federal power.

(f) Authorization of appropriations. There are authorized to be appropriated to carry out this section \$ 750,000, non-reimbursable, to remain available until expended.

**HISTORY:**

(Oct. 24, 1992, P.L. 102-486, Title XXVI, § 2605, as added Aug. 8, 2005, P.L. 109-58, Title V, § 503(a), 119 Stat. 776.)

**HISTORY; ANCILLARY LAWS AND DIRECTIVES**

**Explanatory notes:**

A prior § 3505 (Act Oct. 24, 1992, P.L. 102-486, Title XXVI, § 2605, 106 Stat. 3115; Nov. 2, 1994, P.L. 103-437, § 10(e)(1), (2)(D), 108 Stat. 4589), relating to Indian energy resources, was replaced in the general revision of Title XXVI of Act Oct. 24, 1992, P.L. 102-486, by § 503(a) of Act Aug. 8, 2005, P.L. 109-58. Such section established the Indian Energy Resource Commission.

**NOTES:**

**Research Guide:**

**Texts:**

Cohen's Handbook of Federal Indian Law (Matthew Bender), ch 17, Natural Resources § 17.03.



LEXSTAT 25 USCS 3501

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TITLE 25. INDIANS  
CHAPTER 37. INDIAN ENERGY

**Go to the United States Code Service Archive Directory**

*25 USCS § 3506*

§ 3506. Wind and hydropower feasibility study

(a) Study. The Secretary of Energy, in coordination with the Secretary of the Army and the Secretary, shall conduct a study of the cost and feasibility of developing a demonstration project that uses wind energy generated by Indian tribes and hydropower generated by the Army Corps of Engineers on the Missouri River to supply firming power to the Western Area Power Administration.

(b) Scope of study. The study shall--

(1) determine the economic and engineering feasibility of blending wind energy and hydropower generated from the Missouri River dams operated by the Army Corps of Engineers, including an assessment of the costs and benefits of blending wind energy and hydropower compared to current sources used for firming power to the Western Area Power Administration;

(2) review historical and projected requirements for, patterns of availability and use of, and reasons for historical patterns concerning the availability of firming power;

(3) assess the wind energy resource potential on tribal land and projected cost savings through a blend of wind and hydropower over a 30-year period;

(4) determine seasonal capacity needs and associated transmission upgrades for integration of tribal wind generation and identify costs associated with these activities;

(5) include an independent tribal engineer and a Western Area Power Administration customer representative as study team members; and

(6) incorporate, to the extent appropriate, the results of the Dakotas Wind Transmission study prepared by the Western Area Power Administration.

(c) Report. Not later than 1 year after the date of enactment of the Energy Policy Act of 2005 [enacted Aug. 8, 2005], the Secretary of Energy, the Secretary, and the Secretary of the Army shall submit to Congress a report that describes the results of the study, including--

(1) an analysis and comparison of the potential energy cost or benefits to the customers of the Western Area Power Administration through the use of combined wind and hydropower;

(2) an economic and engineering evaluation of whether a combined wind and hydropower system can reduce reservoir fluctuation, enhance efficient and reliable energy production, and provide Missouri River management flexibility;

(3) if found feasible, recommendations for a demonstration project to be carried out by the Western Area Power Administration, in partnership with an Indian tribal government or tribal energy resource development organization, and

25 USCS § 3506

Western Area Power Administration customers to demonstrate the feasibility and potential of using wind energy produced on Indian land to supply firming energy to the Western Area Power Administration; and

(4) an identification of--

(A) the economic and environmental costs of, or benefits to be realized through, a Federal-tribal-customer partnership; and

(B) the manner in which a Federal-tribal-customer partnership could contribute to the energy security of the United States.

(d) Funding.

(1) Authorization of appropriations. There is authorized to be appropriated to carry out this section \$ 1,000,000, to remain available until expended.

(2) Nonreimbursability. Costs incurred by the Secretary in carrying out this section shall be nonreimbursable.

**HISTORY:**

(Oct. 24, 1992, P.L. 102-486, Title XXVI, § 2606, as added Aug. 8, 2005, P.L. 109-58, Title V, § 503(a), 119 Stat. 777.)

**HISTORY; ANCILLARY LAWS AND DIRECTIVES**

**Explanatory notes:**

A prior § 3506 (Act Oct. 24, 1992, P.L. 102-486, Title XXVI, § 2606, 106 Stat. 3118), relating to Indian energy resources, was replaced in the general revision of Title XXVI of Act Oct. 24, 1992, P.L. 102-486, by § 503(a) of Act Aug. 8, 2005, P.L. 109-58. Such section provided for a tribal government energy assistance program.

**NOTES:**

**Research Guide:**

**Texts:**

Cohen's Handbook of Federal Indian Law (Matthew Bender), ch 17, Natural Resources § 17.03.



LEXSTAT 43 USC 666

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TITLE 43. PUBLIC LANDS  
CHAPTER 15. APPROPRIATION OF WATERS; RESERVOIR SITES

**Go to the United States Code Service Archive Directory**

*43 USCS § 666*

§ 666. Suits for adjudication of water rights

(a) Joinder of United States as defendant; costs. Consent is hereby given to join the United States as a defendant in any suit (1) for the adjudication of rights to the use of water of a river system or other source, or (2) for the administration of such rights, where it appears that the United States is the owner of or is in the process of acquiring water rights by appropriation under State law, by purchase, by exchange, or otherwise, and the United States is a necessary party to such suit. The United States, when a party to any such suit, shall (1) be deemed to have waived any right to plead that the State laws are inapplicable or that the United States is not amenable thereto by reason of its sovereignty, and (2) shall be subject to the judgments, orders, and decrees of the court having jurisdiction, and may obtain review thereof, in the same manner and to the same extent as a private individual under like circumstances: *Provided*, That no judgment for costs shall be entered against the United States in any such suit.

(b) Service of summons. Summons or other process in any such suit shall be served upon the Attorney General or his designated representative.

(c) Joinder in suits involving use of interstate streams by State. Nothing in this Act shall be construed as authorizing the joinder of the United States in any suit or controversy in the Supreme Court of the United States involving the right of States to the use of the water of any interstate stream.

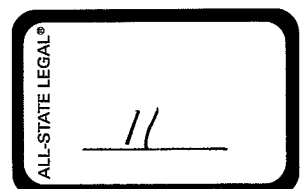
**HISTORY:**

(July 10, 1952, ch 651, Title II, § 208(a)-(c), 66 Stat. 560.)

**HISTORY; ANCILLARY LAWS AND DIRECTIVES**

**References in text:**

"This Act", referred to in this section, is Act July 10, 1952, ch 651, 66 Stat. 549, popularly known as the Departments of State, Justice, Commerce, and the Judiciary Appropriation Act of 1953. For full classification of this Act, consult USCS Tables volumes.



43 USCS § 666

Explanatory notes:

Subsection (d) of § 208 of Act July 10, 1952, contained a limitation on the use of any appropriation in the act to prepare or prosecute the suit in the United States District Court for the Southern District of California by the United States v. Fallbrook Public Utility Corporation and was not codified.

**NOTES:**

Code of Federal Regulations:

Department of the Army--Litigation, 32 *CFR* 516.1 et seq.

Related Statutes & Rules:

Jurisdiction of District Court, 28 *USCS* § 1345.

Tucker Act suit against United States, 28 *USCS* § 1346.

Award of costs in civil actions brought by or against United States, 28 *USCS* § 2412.

Service of summons upon United States, *USCS Rules of Civil Procedure*, Rule 4(d)(4).

This section is referred to in 28 *USCS* § 2409a.

Research Guide:

Federal Procedure:

16 Moore's Federal Practice (Matthew Bender 3d ed.), ch 105, Other Subject Matter Jurisdiction Statutes § 105.09.

17A Moore's Federal Practice (Matthew Bender 3d ed.), ch 120, Dual State and Federal Judicial Structure § 120.22.

17A Moore's Federal Practice (Matthew Bender 3d ed.), ch 122, Abstention Doctrines § 122.06.

2 Civil Rights Actions (Matthew Bender), ch 3, The Relationship Between State and Federal Courts P 3.17.

19 Fed Proc L Ed, Indians and Indian Affairs §§ 46:536-539.

24A Fed Proc L Ed, Natural and Marine Resources §§ 56:2053, 2059.

29 Fed Proc L Ed, Public Lands and Property §§ 66:495, 498, 499, 500.

Am Jur:

41 *Am Jur 2d*, *Indians; Native Americans* § 98.

78 *Am Jur 2d*, *Waters* §§ 26, 68.

Am Jur Trials:

Preparing and Using Maps, 2 *Am Jur Trials*, p. 669.

Forms:

1B Fed Procedural Forms L Ed, Administrative Procedure § 2:129.

20B *Am Jur Pl & Pr Forms* (Rev ed), Public Lands § 12.

Annotations:

Injunction against exercise of power of eminent domain. 93 *ALR2d* 465.

## 43 USCS § 666

## Texts:

Cohen's Handbook of Federal Indian Law (Matthew Bender), ch 6, Tribal/State Relationship § 6.04.  
 Cohen's Handbook of Federal Indian Law (Matthew Bender), ch 7, Civil Jurisdiction § 7.05.  
 Cohen's Handbook of Federal Indian Law (Matthew Bender), ch 19, Water Rights §§ 19.04, 19.05.

## Law Review Articles:

Veeder. Water Rights in the Coal Fields of The Yellowstone River Basin. *40 Law & Contemp Prob* 77, Winter 1976.  
 Price; Weatherford. Indian Water Rights in Theory and Practice: Navajo Experience in the Colorado River Basin. *40 Law & Contemp Prob* 97, Winter 1976.

## Interpretive Notes and Decisions:

**I. IN GENERAL** 1. Generally 2. Construction and effect 3. Purpose 4. Relationship with other laws 5. Law governing 6. Suits covered by statute 7.--Adjudication of water rights 8.--Administration of water rights 9. What constitutes river system

**II. PRACTICE AND PROCEDURE** 10. Jurisdiction 11. Concurrent jurisdiction 12. Removal of action 13. Parties 14. Injunction 15. Dismissal 16. Res judicata

**I. IN GENERAL 1. Generally**

43 USCS § 666 permits United States to be joined in state action in cases in which United States owns water rights and is necessary party to suit, and permits complete adjudication in state court action, thereby preventing parties' frustration over inability to obtain jurisdiction over United States. *United States v Akin* (1974, CA10 Colo) 504 F2d 115, rev'd on other grounds (1976) 424 US 800, 96 S Ct 1236, 47 L Ed 2d 483, 9 Env't Rep Cas 1016, reh den (1976) 426 US 912, 96 S Ct 2239, 48 L Ed 2d 839 and (criticized in *Jaffee v Society of the N.Y. Hosp.* (1997, SD NY) 1997 US Dist LEXIS 17219) and (criticized in *Bowshier v Daimlerchrysler Motors Co.* (2004, SD Ohio) 2004 US Dist LEXIS 30552).

McCarran Amendment (43 USCS § 666) does not contemplate that only state water code administrators may administer federal reserved rights. *United States v Anderson* (1982, ED Wash) 591 F Supp 1.

McCarran Amendment (43 USCS § 666) applies to Indian water rights even though those rights may be appurtenant to fee simple Indian land. *United States v Bluewater-Toltec Irrigation Dist.* (1984, DC NM) 580 F Supp 1434, aff'd (1986, CA10 NM) 806 F2d 986.

**2. Construction and effect**

Under 43 USCS § 666, granting consent to join United States as defendant in any suit for adjudication of rights to use of water of river system or other source, or for administration of such rights, "where it appears that the United States is the owner of or is in the process of acquiring water rights by appropriation under State law, by purchase, by exchange, or otherwise," such appropriated rights are not limited to those acquired under state law, but include all appropriated rights, riparian rights, and reserved rights. *United States v District Court of County of Eagle* (1971) 401 US 520, 28 L Ed 2d 278, 91 S Ct 998, 2 Env't Rep Cas 1338, 1 ELR 20189.

Consent to join United States as defendant in state court proceeding given by McCarran Amendment [43 USCS § 666] extends to determination of federal reserved rights held on behalf of Indians; 43 USCS § 666 in no way abridges any substantive claim on behalf of Indians under doctrine of reserved rights. *Colorado River Water Conservation Dist. v United States* (1976) 424 US 800, 96 S Ct 1236, 47 L Ed 2d 483, 9 Env't Rep Cas 1016, reh den (1976) 426 US 912, 96 S Ct 2239, 48 L Ed 2d 839 and (criticized in *Jaffee v Society of the N.Y. Hosp.* (1997, SD NY) 1997 US Dist LEXIS 17219) and (criticized in *Bowshier v Daimlerchrysler Motors Co.* (2004, SD Ohio) 2004 US Dist LEXIS 30552).

43 USCS § 666 waives United States' sovereign immunity when United States is defendant in state or federal action so that all competing claims to water rights may be fully and fairly adjudicated; however, Congress did not intend thereby to limit forums available to United States as plaintiff by narrowing federal court jurisdiction. *United States v*

## 43 USCS § 666

*Cappaert* (1974, CA9 Nev) 508 F2d 313, 5 ELR 20494, affd (1976) 426 US 128, 48 L Ed 2d 523, 96 S Ct 2062, 6 ELR 20540.

McCarran Amendment, 43 USCS § 666, waives United States' immunity from suit, not only for administration of water rights acquired after statute's enactment, but also for administration of water rights acquired before law came into effect. *State Eng'r v S. Fork Band of the Te-Moak Tribe of W. Shoshone Indians of Nev.* (2003, CA9 Nev) 339 F3d 804, 2003 CDOS 6623, 2003 Daily Journal DAR 8299.

43 USCS § 666 does not mandate absolute policy of deference to state proceedings. *Hage v United States* (1996) 35 Fed Cl 147.

### 3. Purpose

Sole purpose of 43 USCS § 666, giving consent to join United States as defendant in any suit for adjudication of rights to use of water of river system or other source where United States is owner of or is in process of acquiring such rights, is to allow United States to be joined in suit wherein it is necessary to adjudicate all rights of various owners on given stream. *United States v District Court of County of Eagle* (1971) 401 US 520, 28 L Ed 2d 278, 91 S Ct 998, 2 Env't Rep Cas 1338, 1 ELR 20189.

McCarran Amendment (43 USCS § 666) does not constitute waiver of governmental immunity where water rights and disputes are involved in private park claim against United States because McCarran amendment was designed for no other purpose than to allow United States to be joined in suits where it was necessary to adjudicate all of rights of various owners in given stream; where plaintiff's action clearly does not involve adjudication of water rights at all, McCarran Amendment does not affect governmental immunity from flood damage. *Lenoir v Porters Creek Watershed Dist.* (1978, CA6 Tenn) 586 F2d 1081.

43 USCS § 666 was enacted for purpose of waiving federal government's sovereign immunity in state stream adjudications. *Hage v United States* (1996) 35 Fed Cl 147.

### 4. Relationship with other laws

McCarran Amendment (43 USCS § 666) does not constitute exception provided by Act of Congress, for purposes of 28 USCS § 1345 giving Federal District Courts original jurisdiction of all civil actions commenced by United States, "[e]xcept as otherwise provided by Act of Congress"; thus Federal District Court has jurisdiction under § 1345 over action brought by United States, as trustee for Indian tribes and as owner of various non-Indian government claims, for determination of water rights. *Colorado River Water Conservation Dist. v United States* (1976) 424 US 800, 96 S Ct 1236, 47 L Ed 2d 483, 9 Env't Rep Cas 1016, reh den (1976) 426 US 912, 96 S Ct 2239, 48 L Ed 2d 839 and (criticized in *Jaffee v Society of the N.Y. Hosp.* (1997, SD NY) 1997 US Dist LEXIS 17219) and (criticized in *Bowshier v Daimler-chrysler Motors Co.* (2004, SD Ohio) 2004 US Dist LEXIS 30552).

Federal water rights are not dependent upon state law or state procedures, and they need not be adjudicated only in state court; McCarran amendment (43 USCS § 666), which provides for consent to join United States as defendant in any suit for adjudication of rights to use of water where United States owns or is acquiring water rights and is necessary party to such suit, did not repeal jurisdiction of federal courts to adjudicate water rights claims of United States under 28 USCS § 1345, giving Federal District Courts original jurisdiction of all civil actions commenced by United States, except as otherwise provided by Act of Congress. *Cappaert v United States* (1976) 426 US 128, 48 L Ed 2d 523, 96 S Ct 2062, 6 ELR 20540.

McCarran Amendment (43 USCS § 666) does not do away with federal jurisdiction over water rights claims brought under 28 USCS § 1345; Amendment does not limit jurisdictional reach of 28 USCS § 1362, which gives Federal District Courts original jurisdiction of all civil actions brought by any Indian tribe where matter in controversy arises under Constitution, laws or treaties of United States; 25 USCS § 1322(b) and 28 USCS § 1360(b) only qualify import of general consent to state jurisdiction given by those sections and do not purpose to limit special consent to jurisdiction given by Amendment. *Arizona v San Carlos Apache Tribe* (1983) 463 US 545, 77 L Ed 2d 837, 103 S Ct 3201, 13 ELR 20817, reh den (1983) 464 US 874, 78 L Ed 2d 185, 104 S Ct 209.

43 USCS § 666 does not waive United States' sovereign immunity from payment of filing fee when submitting notice of claim to state in suit adjudicating water rights. *United States v Idaho* (1993) 508 US 1, 123 L Ed 2d 563, 113 S Ct 1893, 93 CDOS 3206, 93 Daily Journal DAR 5475, 23 ELR 20821, 7 FLW Fed S 242.

## 43 USCS § 666

43 USCS § 666 does not repeal United States jurisdiction over water cases under 28 USCS § 1345. *United States v Akin* (1974, CA10 Colo) 504 F2d 115, rev'd on other grounds (1976) 424 US 800, 96 S Ct 1236, 47 L Ed 2d 483, 9 Env't Rep Cas 1016, reh den (1976) 426 US 912, 96 S Ct 2239, 48 L Ed 2d 839 and (criticized in *Jaffee v Society of the N.Y. Hosp.* (1997, SD NY) 1997 US Dist LEXIS 17219) and (criticized in *Bowshier v Daimlerchrysler Motors Co.* (2004, SD Ohio) 2004 US Dist LEXIS 30552).

McCarran Amendment (43 USCS § 666) does not implicitly prohibit removal of water adjudication suit to federal court; general removal statute (28 USCS § 1441(a)) states that actions brought in state court over which federal court would have jurisdiction may be removed unless otherwise expressly provided by act of Congress, and silence of 43 USCS § 666 on subject of removal hardly brings this exception into play. *In re General Adjudication of All Rights to use Water & Water Rights etc.* (1982, DC SD) 531 F Supp 449.

Abstention is required in state's suit to enforce water rights decree against Indian tribe, even though U.S., on behalf of tribe, removed suit to federal court, where 43 USCS § 666 codifies clear federal policy against "piecemeal adjudication of water rights," because decree was issued by state court and state court can and should oversee its enforcement. *State Eng'r v South Fork Band of the Te-Moak Tribe* (2000, DC Nev) 114 F Supp 2d 1046.

### 5. Law governing

43 USCS § 666, reciting that United States when party to "any suit (1) for the adjudication of rights to the use of water of a river system or other source, or (2) for the administration of such rights, where it appears that the United States is the owner of or is in the process of acquiring water rights" shall be deemed to have waived any right to plead that state laws are inapplicable, did not preclude United States from invoking federal statutes and decisions in support of its claim that it need not obtain permit from state to use underground waters in naval installation; all laws, both state and federal, would be considered insofar as they were relevant; Federal government would not be required to first secure permission of and from Nevada state engineer's office before it could make use of ground or percolating water developed in its own wells, drilled at its own expense, upon its reserved lands constituting ammunition depot. *Nevada ex rel. Shamberger v United States* (1958, DC Nev) 165 F Supp 600.

State water court must follow federal law with respect to Indian and federal reserved rights, since grant of concurrent jurisdiction to states to adjudicate water rights in no way diminished nature of substantive rights. *State ex rel. Greely v Confederated Salish & Kootenai Tribes* (1985) 219 Mont 76, 712 P2d 754.

In general adjudication of water rights in state court under the provisions of 43 USCS § 666, the United States is bound by state law and therefore must quantify the amount of water claimed under the reservation doctrine at the time of the general adjudication of water rights. *Avondale Irrigation Dist. v North Idaho Properties* (1974) 96 Idaho 1, 523 P2d 818, appeal after remand, remanded (1978) 99 Idaho 30, 577 P2d 9, 8 ELR 20458.

### 6. Suits covered by statute

Action of state of Nevada seeking declaration that United States may not make use of underground waters developed by wells located on naval ammunition depot without applying therefor pursuant to state law was barred by sovereign immunity of defendant, 43 USCS § 666(a) not being applicable thereto. *Nevada ex rel. Shamberger v United States* (1960, CA9 Nev) 279 F2d 699.

Waiver of sovereign immunity contained in 43 USCS § 666 does not apply to private suit. *Gardner v Stager* (1996, CA9 Nev) 103 F3d 886, 96 CDOS 9428, 96 Daily Journal DAR 15492, cert den (1997) 522 US 811, 139 L Ed 2d 18, 118 S Ct 54.

Waiver of sovereign immunity provided in 43 USCS § 666 is limited to suits involving comprehensive adjudication or administration of all rights in water system; thus, district court properly held that plaintiff's action for damages and recovery of funds paid pursuant to allegedly illegal contract fell outside statute. *Fent v Oklahoma Water Resources Bd.* (2000, CA10 Okla) 235 F3d 553, 2001 Colo JC A R 194 (criticized in *Diamond v County of Sacramento* (2006, ED Cal) 2006 US Dist LEXIS 6259).

43 USCS § 666 does not contemplate jurisdiction in either state or federal court in case in which municipal corporation attempts to enjoin United States from exercise of its right of eminent domain in order to acquire water rights to transfer to another municipality in compensation for water rights taken by United States. *Durham v United States* (1958, DC NH) 167 F Supp 436.

## 43 USCS § 666

Application to state court to correct decree entered thirty-five years previously adjudicating water rights of stream came within the purview of 43 USCS § 666(a) subjecting United States to jurisdiction of state court. *United States v Hennen* (1969, DC Nev) 300 F Supp 256.

Fact that suit concerns rights to percolating ground water, which is not subject to state law, as well as Indian water rights does not prevent state court jurisdiction of suit under 43 USCS § 666. Re Determination of Conflicting Rights etc. *In re Determination of Conflicting Rights etc.* (1980, DC Ariz) 484 F Supp 778, revd on other grounds, remanded (1982, CA9 Ariz) 668 F2d 1093, revd on other grounds, remanded (1983) 463 US 545, 77 L Ed 2d 837, 103 S Ct 3201, 13 ELR 20817, reh den (1983) 464 US 874, 78 L Ed 2d 185, 104 S Ct 209.

**7.--Adjudication of water rights**

Supplemental water adjudication suit in Colorado state court, asking all owners and claimants of water rights in Eagle River and its tributaries to file statement of claim and to appear in regard to all water rights owned or claimed by them, is general adjudication of all rights of various owners on given stream within meaning of rule that only general adjudications are encompassed by 43 USCS § 666, which gives consent to join United States as defendant in any suit for adjudication of rights to use of water of river system or other source where United States is owner of or is in process of acquiring such rights; and this is so even though owners of rights previously decreed in adjudication are not before court. *United States v District Court of County of Eagle* (1971) 401 US 520, 28 L Ed 2d 278, 91 S Ct 998, 2 Env't Rep Cas 1338, 1 ELR 20189.

Waiver of sovereign immunity provided in 43 USCS § 666 is limited to suits involving comprehensive adjudication or administration of all rights in water system; thus, district court properly held that plaintiff's action for damages and recovery of funds paid pursuant to allegedly illegal contract fell outside statute. *Fent v Oklahoma Water Resources Bd.* (2000, CA10 Okla) 235 F3d 553, 2001 Colo JC A R 194 (criticized in *Diamond v County of Sacramento* (2006, ED Cal) 2006 US Dist LEXIS 6259).

Plaintiffs' case, which involved only four water districts, non-profit corporation, and private nursery, was far from comprehensive suit contemplated by McCarran Amendment; because not all potential claimants to water at issue had been made parties to action, United States had not consented to suit. *Wagoner County Rural Water Dist. No. 2 v Grand River Dam Auth.* (2009, CA10 Okla) 577 F3d 1255.

Attempted adjudication of federal water rights will not be recognized where state court (1) lacked jurisdiction over United States for failure to serve process upon Attorney General of United States or his designated representative pursuant to 43 USCS § 666(b); and (2) lacked jurisdiction over subject matter for failure of litigation to conform to requirements of general litigation of all water rights pursuant to 43 USCS § 666(a). *Park Center Water Dist. & the Canyon Heights Irrig. & Reservoir Co.* (1977) 84 ID 87.

Where non-Indian owners of two appropriative water rights on reservation applied to Montana Department of Natural Resources and Conservation to change use of water rights from irrigation to recreation, Supreme Court of Montana rejected tribe's argument that change of use proceedings were improper piecemeal adjudications prohibited by McCarran Amendment, 43 USCS § 666. *Confederated Salish & Kootenai Tribes v Clinch* (2007) 2007 MT 63, 336 Mont 302, 158 P3d 377, reh den (2007, Mont) 2007 Mont LEXIS 234.

**8.--Administration of water rights**

Waiver of sovereign immunity provided in 43 USCS § 666 is limited to suits involving comprehensive adjudication or administration of all rights in water system; thus, district court properly held that plaintiff's action for damages and recovery of funds paid pursuant to allegedly illegal contract fell outside statute. *Fent v Oklahoma Water Resources Bd.* (2000, CA10 Okla) 235 F3d 553, 2001 Colo JC A R 194 (criticized in *Diamond v County of Sacramento* (2006, ED Cal) 2006 US Dist LEXIS 6259).

McCarran Amendment (43 USCS § 666) waives sovereign immunity of United States in action where plaintiffs and cross-claimant requested District Court to adjudicate rights of all parties and United States relating to water acquired by government for operation of projects under Reclamation Act of 1902 and where cross-complainants requested Court to delineate applicable laws by which United States, as cross-claim defendant, was to administer project and waters acquired for it. *Barcellos & Wolfson, Inc. v Westlands Water Dist.* (1980, ED Cal) 491 F Supp 263.

## 43 USCS § 666

Action to quiet title to previously adjudicated water rights is proceeding "administering" those rights within purview of 43 USCS § 666(a)(2). *Federal Youth Center v District Court of County of Jefferson* (1978) 195 Colo 55, 575 P2d 395.

### 9. What constitutes river system

Under 43 USCS § 666(a), granting consent to join United States as defendant in any suit for adjudication of "rights to the use of water of a river system" where it appears that United States is owner of or in process of acquiring water rights by appropriation under state law and United States is necessary party to such suit, phrase "rights to the use of water of a river system" is broad enough to embrace waters reserved for use and benefit of federally reserved lands; Eagle River, tributary of Colorado River, and Eagle River's tributaries are "river systems" within meaning of 43 USCS § 666(a); term "river system" must be read as embracing one within particular state's jurisdiction. *United States v District Court of County of Eagle* (1971) 401 US 520, 28 L Ed 2d 278, 91 S Ct 998, 2 Env't Rep Cas 1338, 1 ELR 20189.

## II. PRACTICE AND PROCEDURE 10. Jurisdiction

McCarran amendment (43 USCS § 666), which provides for consent to join United States as defendant in any suit for adjudication of water rights where United States owns or is acquiring such rights by appropriation under state law or otherwise, does not affect jurisdiction of Federal District Courts under general federal question jurisdiction of 28 USCS § 1331; thus Federal District Court has jurisdiction under § 1331 in action brought by United States, as trustee for Indian tribes and as owner of various non-Indian government claims, for determination of water rights; under 43 USCS § 666 there is consent to join United States as defendant in state court action when action is one to determine federal reserve water rights held on behalf of Indians; thus, state court has jurisdiction over Indian water rights under amendment in state court action brought to adjudicate claims of United States which had asserted reserve water rights on its own behalf and on behalf of Indian tribes, as well as rights based on state law. *Colorado River Water Conservation Dist. v United States* (1976) 424 US 800, 96 S Ct 1236, 47 L Ed 2d 483, 9 Env't Rep Cas 1016, reh den (1976) 426 US 912, 96 S Ct 2239, 48 L Ed 2d 839 and (criticized in *Jaffee v Society of the N.Y. Hosp.* (1997, SD NY) 1997 US Dist LEXIS 17219) and (criticized in *Bowshier v Daimlerchrysler Motors Co.* (2004, SD Ohio) 2004 US Dist LEXIS 30552).

In litigation to adjudicate federal and Indian water rights in Montana, McCarran Amendment overrides sovereign immunity of United States, but it does not grant jurisdiction to state by repealing state constitutional disclaimer of jurisdiction over Indian lands; state legislative action alone suffices to repeal such disclaimer, and after 1968, with enactment of 25 USCS §§ 1321(a) and 1322(a), state may repeal disclaimer only with consent of affected tribes. Northern Cheyenne Tribe etc. *Northern Cheyenne Tribe etc. v Adsit* (1982, CA9 Mont) 668 F2d 1080, rev'd on other grounds, remanded (1983) 463 US 545, 77 L Ed 2d 837, 103 S Ct 3201, 13 ELR 20817, reh den (1983) 464 US 874, 78 L Ed 2d 185, 104 S Ct 209.

Congress intended waiver of immunity under 43 USCS § 666(a)(2) only after general stream determination under § 666(a)(1) has been made; and thus, action by municipal corporation representing interest of water rights holders in California's central valley, in which it is alleged that operation by federal defendants of Central Valley Project diminishes quantity and quality of corporation's water, is not reviewable by courts under § 666(a)(2), where there has been no prior adjudication of relative general stream water rights in action; however failure to meet requirements for review under § 666 does not preclude review under more general grant of jurisdiction in 28 USCS § 1331. *South Delta Water Agency v United States, Dep't of Interior, Bureau of Reclamation* (1985, CA9 Cal) 767 F2d 531.

Fact that tribe does not believe United States government's claim on behalf of tribe is proper in all respects does not divest Arizona courts of jurisdiction to hear water rights dispute under 43 USCS § 666. *United States v White Mountain Apache Tribe* (1986, CA9 Ariz) 784 F2d 917.

State may not compel United States to comply with fee requirements, nor may it compel United States and Indian tribe to comply with registration requirements stipulated in its statutory procedures for mass adjudication of surface rights. *United States v Oregon, Water Resources Dep't* (1994, CA9 Or) 44 F3d 758, 94 CDOS 9768, 94 Daily Journal DAR 18141, cert den (1995) 516 US 943, 133 L Ed 2d 302, 116 S Ct 378.

Absent clear indications, court could not impute to Congress intent to repeal, sub silentio, deeply-rooted legal doctrine of prior exclusive jurisdiction; therefore, because McCarran Amendment, 43 USCS § 666(a), did not repeal doctrine of prior exclusive jurisdiction, but instead affirmed that longstanding jurisdictional limitation, doctrine of prior exclusive jurisdiction was jurisdictional bar to district court's exercise of jurisdiction over state's contempt proceedings against Indian tribe, and district court's order remanding case to state court was affirmed on ground that court lacked

## 43 USCS § 666

jurisdiction, not as matter of abstention. *State Eng'r v S. Fork Band of the Te-Moak Tribe of W. Shoshone Indians of Nev.* (2003, CA9 Nev) 339 F3d 804, 2003 CDOS 6623, 2003 Daily Journal DAR 8299.

McCarran Amendment (43 USCS § 666(a)) does not independently confer federal jurisdiction. *United States v Bluewater-Toltec Irrigation Dist.* (1984, DC NM) 580 F Supp 1434, affd (1986, CA10 NM) 806 F2d 986.

Immunity waiver under 43 USCS § 666 in water rights adjudication could not be applied retroactively so as to confer jurisdiction on Commonwealth of Puerto Rico administrative agency to subject U.S. Navy installation to water permit proceedings, where retroactive application would impose new legal consequences upon Navy in that previous agreement with Commonwealth permitted Navy to draw river water free of charge, and there was neither an express prescription of retroactive reach, nor ascertainable Congressional intent that statute be retroactively applicable. *United States v Puerto Rico* (2001, DC Puerto Rico) 144 F Supp 2d 46, affd, remanded (2002, CA1 Puerto Rico) 287 F3d 212, 32 ELR 20641.

State legislature's enactment of water use act constitutes valid and binding consent of people of Montana to Congressional grant of state jurisdiction over Indian reserved water rights under 43 USCS § 666; act is adequate on its face to allow state water court to adjudicate Indian and federal reserved water rights. *State ex rel. Greely v Confederated Salish & Kootenai Tribes* (1985) 219 Mont 76, 712 P2d 754.

43 USCS § 666 does not preclude federal courts from exercising jurisdiction regarding water rights claims, and does not limit jurisdiction of Court of Federal Claims to hear water rights taking claims. *Hage v United States* (1996) 35 Fed Cl 147.

State water court's grant of motion for stay pending resolution of federal court proceeding was not abuse of discretion where federal claims would not affect water court's ability to quantify federal reserved water right; scope of waiver of sovereign immunity that was contained in federal McCarran Amendment, 43 USCS § 666, was not broad enough to allow state courts to evaluate or adjudicate federal administrative law claims that were at issue in federal case, such that water court did not abuse its discretion by staying proceedings for relatively brief period of time. *United States v Colo. State Eng'r (In re Water Rights of United States)* (2004, Colo) 101 P3d 1072.

### 11. Concurrent jurisdiction

Immediate effect of McCarran amendment (43 USCS § 666), which provides for consent to joint United States as defendant in any suit for adjudication of water rights where United States owns or is acquiring such rights by appropriation under state law or otherwise, is to give consent to jurisdiction in state court concurrent with jurisdiction in federal court over controversies involving federal rights to use of water; there is no irreconcilability in existence of concurrent state and federal jurisdiction. *Colorado River Water Conservation Dist. v United States* (1976) 424 US 800, 96 S Ct 1236, 47 L Ed 2d 483, 9 Env't Rep Cas 1016, reh den (1976) 426 US 912, 96 S Ct 2239, 48 L Ed 2d 839 and (criticized in *Jaffee v Society of the N.Y. Hosp.* (1997, SD NY) 1997 US Dist LEXIS 17219) and (criticized in *Bowshier v Daimler-chrysler Motors Co.* (2004, SD Ohio) 2004 US Dist LEXIS 30552).

McCarran Amendment (43 USCS § 666) provides state courts with jurisdiction to adjudicate Indian water rights and applies to all states, including states that were admitted to union subject to federal legislation that reserved absolute jurisdiction and control over Indian lands in Congress; where states have jurisdiction to adjudicate Indian water rights, concurrent federal suits brought by Indian tribes seeking adjudication only of Indian water rights, are subject to dismissal in light of clear federal policies underlying § 666. *Arizona v San Carlos Apache Tribe* (1983) 463 US 545, 77 L Ed 2d 837, 103 S Ct 3201, 13 ELR 20817, reh den (1983) 464 US 874, 78 L Ed 2d 185, 104 S Ct 209.

43 USCS § 666, does no more than create concurrent jurisdiction for adjudication of water rights and neither permits nor prohibits removal of action. *National Audubon Soc. v Department of Water & Power* (1980, ED Cal) 496 F Supp 499.

Adjudication of Indian water rights in state court can be comprehensive under waiver of sovereign immunity provision of McCarran Amendment (43 USCS § 666), despite contention that state court lacks jurisdiction over Indian water rights on lands held in fee, rather than in trust by United States. *United States v Bluewater-Toltec Irrigation Dist.* (1984, DC NM) 580 F Supp 1434, affd (1986, CA10 NM) 806 F2d 986.

Contrary to tribe's argument, McCarran Amendment, 43 USCS § 666, did not deprive equity court of jurisdiction to enforce Globe Equity Decree. In fact, Amendment conferred jurisdiction to state courts that was concurrent to federal

## 43 USCS § 666

jurisdiction, rather than withdrawing jurisdiction. In re General Adjudication of All Rights to use Water in the Gila River system (2006) 212 Ariz 470, 134 P3d 375.

**12. Removal of action**

In state proceeding to determine water rights in San Juan River, United States was properly before state court pursuant to 43 USCS § 666 in its capacity as trustee over Indian land; however neither that Act nor mere fact that United States is defendant implicitly authorizes removal of suit to federal court. *New Mexico ex rel. Reynolds v United States* (1975, DC NM) 408 F Supp 1029.

43 USCS § 666, does no more than create concurrent jurisdiction for adjudication of water rights and neither permits nor prohibits removal of action. *National Audubon Soc. v Department of Water & Power* (1980, ED Cal) 496 F Supp 499.

**13. Parties**

In action against United States' officials and others to compel release of water impounded behind federal dam, or compensation therefor, making United States party would not jeopardize appellate jurisdiction of court of appeals in actions under Tucker Act [28 USCS §§ 1346(a), 1491] by same or other plaintiffs so as to warrant issuance of mandamus or prohibition against making United States party. *California v United States District Court* (1954, CA9) 213 F2d 818.

Action seeking declaratory and injunctive relief as to waters of Upper Rio Grande River was properly dismissed since all persons having interest in the subject matter were not parties, in that United States was improperly joined. *Miller v Jennings* (1957, CA5 Tex) 243 F2d 157, cert den (1957) 355 US 927, 2 L Ed 2d 41, 78 S Ct 39, reh den (1957) 355 US 885, 2 L Ed 2d 115, 78 S Ct 146.

United States is proper party defendant in any general water rights adjudication proceeding, whether brought in federal court or state court, relating to federally created water rights, including those reserved for use by Indian tribes; Indian tribes using federally reserved waters are not, however, granted right of intervention in any such adjudication, with right to be represented by private counsel independent of any possible conflict of interest. *Jicarilla Apache Tribe v United States* (1979, CA10 NM) 601 F2d 1116, cert den (1979) 444 US 995, 62 L Ed 2d 426, 100 S Ct 530.

Fact that Indian tribe does not believe government's claim on behalf of tribe is proper in all respects does not absolve United States of its responsibility as trustee for tribe to assert claim it believes appropriate, in water rights dispute heard in state court under 43 USCS § 666. *United States v White Mountain Apache Tribe* (1986, CA9 Ariz) 784 F2d 917.

United States government's dual role as trustee for Indian tribe and representative of other federal water interests does not, per se, disable it from making water claims for Indians in state litigation under 43 USCS § 666, since government remains under firm obligation to represent tribe's interest forcefully despite other representative obligations, and may be liable for breach of duty, so if tribe is convinced that United States cannot adequately represent tribe, proper remedy is intervention in state proceeding. *White Mountain Apache Tribe v Hodel* (1986, CA9 Ariz) 784 F2d 921, cert den (1986) 479 US 1006, 93 L Ed 2d 700, 107 S Ct 644, reh den (1987) 479 US 1070, 93 L Ed 2d 1012, 107 S Ct 965.

43 USCS § 666 does not authorize private suits to decide priorities between United States and particular claimants, only suits to adjudicate rights of all claimants on stream. *Metropolitan Water Dist. v United States* (1987, CA9 Cal) 830 F2d 139, affd, by split decision (1989) 490 US 920, 104 L Ed 2d 981, 109 S Ct 2273.

**14. Injunction**

District Court properly enjoined Indian tribe's efforts to impede government's work on water rights litigation under 43 USCS § 666, because United States had continuing obligation to present tribe's claim, efforts by government agents or employees to prepare claim were official duties, and tribe's own sovereignty did not extend to preventing federal government from exercising its superior sovereign powers. *United States v White Mountain Apache Tribe* (1986, CA9 Ariz) 784 F2d 917.

Suits for past damages brought by riparian and overlying land owners under Tucker Act [28 USCS §§ 1346(a), 1491] did not constitute election of remedies which would bar such landowners from injunctive relief against future damages in class action brought under 43 USCS § 666. *Rank v United States* (1956, DC Cal) 142 F Supp 1, affd in part and revd in part on other grounds (1961, CA9 Cal) 293 F2d 340, 4 FR Serv 2d 340, mod on other grounds (1962, CA9

## 43 USCS § 666

Cal) 307 F2d 96, affd (1963) 372 US 627, 10 L Ed 2d 28, 83 S Ct 996 (ovrld on other grounds as stated in *California ex rel. State Water Resources Bd. v FERC* (1989, CA9) 877 F2d 743, 19 ELR 21303).

**15. Dismissal**

Although federal District Court action brought by United States, as trustee for certain Indian tribes and as owner of various non-Indian government claims, to determine water rights was not appropriate for dismissal on basis of abstention doctrine, dismissal was warranted for reasons of wise judicial administration so as to allow determination of United States' claims in state court action in which United States had been made defendant under McCarran Amendment [43 USCS § 666] since (1) dismissal furthered amendments' policy of avoiding piecemeal adjudication of water rights in river system, (2) there were apparently no proceedings in District Court, other than filing of complaint, prior to filing of motions to dismiss District Court's action, (3) state water rights were extensively involved in District Court's action, (4) it was 300 miles between District Court and state court, and (5) United States had participated in other state proceedings for determination of water rights. *Colorado River Water Conservation Dist. v United States* (1976) 424 US 800, 96 S Ct 1236, 47 L Ed 2d 483, 9 Env't Rep Cas 1016, reh den (1976) 426 US 912, 96 S Ct 2239, 48 L Ed 2d 839 and (criticized in *Jaffee v Society of the N.Y. Hosp.* (1997, SD NY) 1997 US Dist LEXIS 17219) and (criticized in *Bowshier v Daimler-chrysler Motors Co.* (2004, SD Ohio) 2004 US Dist LEXIS 30552).

Farmers suit against U.S. for reduction of water made available for water users within certain water district was properly dismissed for lack of subject matter jurisdiction because farmers did not qualify for waiver of sovereign immunity under McCarran Amendment, 43 USCS § 666, because McCarran Amendment did not apply to this suit for money damages; nor did farmers qualify for waiver of sovereign immunity under 43 USCS § 390uu because neither recordable contracts nor Barcellos stipulated judgment made them "a contracting entity" under § 390uu. *Orff v United States* (2004, CA9 Cal) 358 F3d 1137, affd (2005) 545 US 596, 125 S Ct 2606, 162 L Ed 2d 544, 18 FLW Fed S 471, 31 ALR Fed 2d 733 and (criticized in *Klamath Irrigation Dist. v United States* (2005) 67 Fed Cl 504, 61 Env't Rep Cas 1385).

**16. Res judicata**

United States was bound by judgment of state court, having jurisdiction of the subject matter and the parties, to the same extent as any other party. *Green River Adjudication v United States* (1965) 17 Utah 2d 50, 404 P2d 251.

[Home Page](#) > [Executive Branch](#) > [Code of Federal Regulations](#) > [Electronic Code of Federal Regulations](#)

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### Title 25: Indians

[Browse Previous](#) | [Browse Next](#)

#### PART 211—LEASING OF TRIBAL LANDS FOR MINERAL DEVELOPMENT

##### Section Contents

##### Subpart A—General

- [§ 211.1 Purpose and scope.](#)
- [§ 211.2 Information collection.](#)
- [§ 211.3 Definitions.](#)
- [§ 211.4 Authority and responsibility of the Bureau of Land Management \(BLM\).](#)
- [§ 211.5 Authority and responsibility of the Office of Surface Mining Reclamation and Enforcement \(OSM\).](#)
- [§ 211.6 Authority and responsibility of the Minerals Management Service \(MMS\).](#)
- [§ 211.7 Environmental studies.](#)
- [§ 211.8 Government employees cannot acquire leases.](#)
- [§ 211.9 Existing permits or leases for minerals issued pursuant to 43 CFR chapter II and acquired for Indian tribes.](#)

##### Subpart B—How To Acquire Leases

- [§ 211.20 Leasing procedures.](#)
- [§ 211.21 \[Reserved\]](#)
- [§ 211.22 Leases for subsurface storage of oil or gas.](#)
- [§ 211.23 Corporate qualifications and requests for information.](#)
- [§ 211.24 Bonds.](#)
- [§ 211.25 Acreage limitation.](#)
- [§ 211.26 \[Reserved\]](#)
- [§ 211.27 Duration of leases.](#)
- [§ 211.28 Unitization and communitization agreements, and well spacing.](#)
- [§ 211.29 Exemption of leases and permits made by organized tribes.](#)

##### Subpart C—Rents, Royalties, Cancellations and Appeals

- [§ 211.40 Manner of payments.](#)
- [§ 211.41 Rentals and production royalty on oil and gas leases.](#)
- [§ 211.42 Annual rentals and expenditures for development on leases other than oil and gas, and geothermal resources.](#)
- [§ 211.43 Royalty rates for minerals other than oil and gas.](#)
- [§ 211.44 Suspension of operations.](#)
- [§ 211.45 \[Reserved\]](#)
- [§ 211.46 Inspection of premises, books and accounts.](#)
- [§ 211.47 Diligence, drainage and prevention of waste.](#)
- [§ 211.48 Permission to start operations.](#)
- [§ 211.49 Restrictions on operations.](#)
- [§ 211.50 \[Reserved\]](#)
- [§ 211.51 Surrender of leases.](#)
- [§ 211.52 Fees.](#)

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12

- § 211.53 Assignments, overriding royalties, and operating agreements.
- § 211.54 Lease or permit cancellation; Bureau of Indian Affairs notice of noncompliance.
- § 211.55 Penalties.
- § 211.56 Geological and geophysical permits.
- § 211.57 Forms.
- § 211.58 Appeals.

**Authority:** Sec. 4, Act of May 11, 1938, (52 Stat. 347); Act of August 1, 1956 (70 Stat. 774): 25 U.S.C. 396a-g; and 25 U.S.C. 2 and 9.

**Source:** 61 FR 35653, July 8, 1996, unless otherwise noted.

## **Subpart A—General**



[top](#)

### **§ 211.1 Purpose and scope.**



[top](#)

- (a) The regulations in this part govern leases and permits for the development of Indian tribal oil and gas, geothermal, and solid mineral resources except as provided under paragraph (e) of this section. These regulations are applicable to lands or interests in lands the title to which is held in trust by the United States or is subject to a restriction against alienation imposed by the United States. These regulations are intended to ensure that Indian mineral owners desiring to have their resources developed are assured that they will be developed in a manner that maximizes their best economic interests and minimizes any adverse environmental impacts or cultural impacts resulting from such development.
- (b) The regulations in this part shall be subject to amendment at any time by the Secretary of the Interior. No regulation that becomes effective after the date of approval of any lease or permit shall operate to affect the duration of the lease or permit, rate of royalty, rental, or acreage unless agreed to by all parties to the lease or permit.
- (c) The regulations of the Bureau of Land Management, the Office of Surface Mining Reclamation and Enforcement, and the Minerals Management Service that are referenced in §§211.4, 211.5, and 211.6 are supplemental to the regulations in this part, and apply to parties holding leases or permits for development of Indian mineral resources unless specifically stated otherwise in this part or in such other Federal regulations.
- (d) Nothing in the regulations in this part is intended to prevent Indian tribes from exercising their lawful governmental authority to regulate the conduct of persons, businesses, operations or mining within their territorial jurisdiction.
- (e) The regulations in this part do not apply to leasing and development governed by regulations in 25 CFR parts 213 (Members of the Five Civilized Tribes of Oklahoma), 226 (Osage), or 227 (Wind River Reservation).

### **§ 211.2 Information collection.**



[top](#)

The information collection requirements contained in this part do not require a review by the Office of Management and Budget under the Paperwork Reduction Act (44 U.S.C. 3501; et seq.).

### **§ 211.3 Definitions.**



[top](#)

As used in this part, the following words and phrases have the specified meaning except where

otherwise indicated:

*Applicant* means any person seeking a permit, lease, or an assignment from the superintendent or area director.

*Approving official* means the Bureau of Indians Affairs official with delegated authority to approve a lease or permit.

*Area director* means the Bureau of Indian Affairs official in charge of an area office.

*Authorized officer* means any employee of the Bureau of Land Management authorized by law or by lawful delegation of authority to perform the duties described in this part and in 43 CFR parts 3160, 3180, 3260, 3280, 3480 and 3590.

*Cooperative agreement* means a binding arrangement between two or more parties purporting to the act of agreeing or of coming to a mutual arrangement that is accepted by all parties to a transaction (e.g., communitization and unitization).

*Director's representative* means the Office of Surface Mining Reclamation and Enforcement director's representative authorized by law or lawful delegation of authority to perform the duties described in 30 CFR part 750.

*Gas* means any fluid, either combustible or non-combustible, that is produced in a natural state from the earth and that maintains a gaseous or rarefied state at ordinary temperature and pressure conditions.

*Geological and geophysical permit* means a written authorization to conduct on-site surveys to locate potential deposits of oil and gas, geothermal or solid mineral resources on the lands.

*Geothermal resources means:*

- (1) All products of geothermal processes, including indigenous steam, hot water and hot brines;
- (2) Steam and other gases, hot water, and hot brines, resulting from water, gas or other fluids artificially introduced into geothermal formations;
- (3) Heat or other associated energy found in geothermal formations; and
- (4) Any by-product derived therefrom.

*In the best interest of the Indian mineral owner* refers to the standards to be applied by the Secretary in considering whether to take an administrative action affecting the interests of an Indian mineral owner. In considering whether it is "in the best interest of the Indian mineral owner" to take a certain action (such as approval of a lease, permit, unitization or communitization agreement), the Secretary shall consider any relevant factor, including, but not limited to: economic considerations, such as date of lease expiration; probable financial effect on the Indian mineral owner; leasability of land concerned; need for change in the terms of the existing lease; marketability; and potential environmental, social, and cultural effects.

*Indian lands* means any lands owned by any individual Indian or Alaska Native, Indian tribe, band, nation, pueblo, community, rancheria, colony, or other tribal group which owns land or interests in the land, the title to which is held in trust by the United States or is subject to a restriction against alienation imposed by the United States.

*Indian mineral owner* means an Indian tribe, band, nation, pueblo community, rancheria, colony, or other tribal group which owns mineral interests in oil and gas, geothermal or solid mineral resources, title to which is held in trust by the United States, or is subject to a restriction against alienation imposed by the United States.

*Indian surface owner* means any individual Indian or Indian tribe whose surface estate is held in trust by the United States, or is subject to restriction against alienation imposed by the United States.

*Lease* means any contract approved by the United States under the Act of May 11, 1938 (52 Stat. 347) (25 U.S.C. 396a-396g), as amended, that authorizes exploration for, extraction of, or removal of any minerals.

*Lessee* means a natural person, proprietorship, partnership, corporation, or other entity that has entered into a lease with an Indian mineral owner, or who has been assigned an obligation to make royalty or other payments required by the lease.

*Lessor* means an Indian mineral owner who is a party to a lease.

*Minerals* includes both metalliferous and non-metalliferous minerals; all hydrocarbons, including oil and gas, coal and lignite of all ranks; geothermal resources; and includes but is not limited to, sand, gravel, pumice, cinders, granite, building stone, limestone, clay, silt, or any other energy or non-energy mineral.

*Minerals Management Service official* means any employee of the Minerals Management Service (MMS) authorized by law or by lawful delegation of authority to perform the duties described in 30 CFR chapter II, subchapters A and C.

*Mining* means the science, technique, and business of mineral development including, but not limited to: opencast work, underground work, and in-situ leaching directed to severance and treatment of minerals; Provided, when sand, gravel, pumice, cinders, granite, building stone, limestone, clay or silt is the subject mineral, an enterprise is considered "mining" only if the extraction of such a mineral exceeds 5,000 cubic yards in any given year.

*Oil* means all nongaseous hydrocarbon substances other than those substances leasable as coal, oil shale, or gilsonite (including all vein-type solid hydrocarbons). Oil includes liquefiable hydrocarbon substances such as drip gasoline and other natural condensates recovered or recoverable in a liquid state from produced gas without resorting to a manufacturing process.

*Permit* means any contract issued by the superintendent and/or area director to conduct exploration on; or removal of less than 5,000 cubic yards per year of common varieties of minerals from Indian lands.

*Permittee* means a person holding or required by this part to hold a permit to conduct exploration operations on; or remove less than 5,000 cubic yards per year of common varieties of minerals from Indian lands.

*Secretary* means the Secretary of the Interior or an authorized representative.

*Solid minerals* means all minerals excluding oil, gas and geothermal resources.

*Superintendent* means the Bureau of Indian Affairs official in charge of the agency office having jurisdiction over the minerals subject to leasing under this part.

#### **§ 211.4 Authority and responsibility of the Bureau of Land Management (BLM).**



[top](#)

The functions of the Bureau of Land Management are found in 43 CFR part 3160—Onshore Oil and Gas Operations, 43 CFR part 3180—Onshore Oil and Gas Unit Agreements: Unproven Area, 43 CFR part 3260—Geothermal Resources Operations, 43 CFR part 3280—Geothermal Resources Unit Agreements: Unproven Areas, 43 CFR part 3480—Coal Exploration and Mining Operations, and 43 CFR part 3590—Solid Minerals (other than coal) Exploration and Mining Operations; and currently include, but are not limited to, resource evaluation, approval of drilling permits, mining and reclamation, production plans, mineral appraisals, inspection and enforcement, and production verification. These regulations, apply to leases and permits approved under this part.

#### **§ 211.5 Authority and responsibility of the Office of Surface Mining Reclamation and Enforcement (OSM).**



[top](#)

The OSM is the regulatory authority for surface coal mining and reclamation operations on Indian lands pursuant to the Surface Mining Control and Reclamation Act of 1977 (30 U.S.C. 1201 et seq.). The relevant regulations for surface coal mining and reclamation operations are found in 30 CFR part 750. Those regulations apply to mining and reclamation on leases approved under this part.

#### **§ 211.6 Authority and responsibility of the Minerals Management Service (MMS).**



[top](#)

The functions of the MMS for reporting, accounting, and auditing are found in 30 CFR chapter II, subchapters A and C, which, apply to leases approved under this part. To the extent the parties to a lease or permit are able to provide reasonable provisions satisfactorily addressing the functions governed by MMS regulations, the Secretary may approve alternate provisions in a lease or permit.

#### **§ 211.7 Environmental studies.**



[top](#)

(a) The Secretary shall ensure that all environmental studies are prepared as required by the National Environmental Policy Act of 1969 (NEPA) and the regulations promulgated by the Council on Environmental Quality (CEQ), found in 40 CFR parts 1500 through 1508.

(b) The Secretary shall ensure that all necessary surveys are performed and clearances obtained in accordance with 36 CFR parts 60, 63, and 800 and with the requirements of the Archaeological and Historic Preservation Act (16 U.S.C. 469 et seq.), the National Historic Preservation Act (16 U.S.C. 470 et seq.), The American Indian Religious Freedom Act (42 U.S.C. 1996), and Executive Order 11593, Protection and Enhancement of the Cultural Environment (3 CFR, 1971 through 1975 Comp., p. 559). If these surveys indicate that a mineral development will have an adverse effect on a property listed on or eligible for listing on the National Register of Historic Places, the Secretary shall:

- (1) Seek the comments of the Advisory Council on Historic Preservation, in accordance with 36 CFR part 800;
- (2) Ensure that the property is avoided, that the adverse effect is mitigated, or;
- (3) Ensure that appropriate excavations or other related research is conducted and ensure that complete data describing the historic property is preserved.

#### **§ 211.8 Government employees cannot acquire leases.**



[top](#)

U.S. Government employees are prevented from acquiring leases or interests in leases by the provisions of 25 CFR part 140 and 43 CFR part 20 pertaining to conflicts of interest and ownership of an interest in trust land.

#### **§ 211.9 Existing permits or leases for minerals issued pursuant to 43 CFR chapter II and acquired for Indian tribes.**



[top](#)

(a) Title to the minerals underlying certain Federal lands, which were previously subject to general leasing and mining laws, is now held in trust by the United States for Indian tribes. Existing mineral prospecting permits, exploration and mining leases on these lands, issued prior to these lands being placed in trust status or becoming Indian lands, pursuant to 43 CFR chapter II (and its predecessor regulations), and all actions on the permits and leases shall be administered by the Secretary in accordance with the regulations set forth in 30 CFR chapters II and VII and 43 CFR chapter II, as applicable, provided, that all payment or reports required by a non-producing lease or permit, issued pursuant to 43 CFR chapter II, shall be made to the superintendent having administrative jurisdiction over the land involved, instead of the officer of the Bureau of Land Management designated in 43 CFR unless specifically stated otherwise in the statutes authorizing the United States to hold the land in trust for an Indian tribe. Producing lease payments and reports will be submitted to the Minerals Management Service in accordance with 30 CFR chapter II, subchapters A and C.

(b) Administrative actions regarding an existing lease or permit under this section, may be appealed pursuant to 25 CFR part 2.

#### **Subpart B—How To Acquire Leases**



[top](#)

## § 211.20 Leasing procedures.



[top](#)

(a) Indian mineral owners may, with the approval of the superintendent or area director, lease their land for mining purposes. No oil and gas lease shall be approved unless it has first been offered for bidding at an advertised lease sale in accordance with this section. Leases for minerals other than oil and gas shall be advertised for bids as prescribed in this section unless the Secretary grants the Indian mineral owners written permission to negotiate for lease. Application for leases shall be made to the superintendent having jurisdiction over the lands.

(b) Indian mineral owners may request that the Secretary prepare and advertise or negotiate (if the requirements of this section have been met) mineral leases on their behalf. If requested by an applicant interested in acquiring rights to Indian-owned minerals, the Secretary shall promptly notify the Indian mineral owner, and advise the owner in writing of the alternatives available, including the right to decline to lease. If the Indian mineral owner decides to have the leases advertised, the Secretary shall consult with the Indian mineral owner concerning the appropriate royalty rate and rental. The Secretary may then undertake the responsibility to advertise and lease in accordance with the following procedures:

(1) Leases shall be advertised to receive optimum competition for bonus consideration, under sealed bid, oral auction, or a combination of both. Notice of such advertisement shall be published in at least one local newspaper and in one trade publication at least thirty (30) days in advance of sale. If applicable, such notice must identify the reservation within which the tracts to be leased are found. No specific description of the tracts to be leased need be published. Specific description of such tracts shall be available at the office of the superintendent and/or area director upon request. The complete text of the advertisement, including a specific description, shall be mailed to each person listed on the appropriate agency or area mailing list. Individuals and companies interested in receiving advertisements of lease sales should send their mailing information to the appropriate superintendent or area director for future reference.

(2) The advertisement shall offer the tracts to the responsible bidder offering the highest bonus. The Secretary, after consultation with the Indian mineral owner, shall establish the rental and royalty rates which shall be stated in the advertisement and shall not be subject to negotiation. The advertisement shall provide that the Secretary reserves the right to reject any or all bids, and that acceptance of the lease bid by the Indian mineral owner is required.

(3) Each sealed bid must be accompanied by a cashier's check, certified check or postal money order, or any combination thereof, payable to the payee designated in the advertisement, in an amount not less than 25 percent of the bonus bid, which shall be returned if that bid is not accepted.

(4) A successful oral auction bidder will be allowed five (5) working days to remit the required 25 percent deposit of the bonus bid.

(5) A successful bidder shall, within thirty (30) days after notification of the bid award, remit to the Secretary the balance of the bonus, the first year's rental, a \$75 filing fee, its prorated share of the advertising costs as determined by the Bureau of Indian Affairs, and file with the Secretary all required bonds. The successful bidder shall also file the lease in completed form at that time. However, for good reasons, the Secretary may grant extensions of time in thirty (30) day increments for filing of the lease and all required bonds, provided that additional extension requests are submitted and approved prior to the expiration of the original thirty (30) days or the previously granted extension. Failure on the part of the bidder to take all reasonable actions necessary to comply with the foregoing shall result in forfeiture of the required payment of 25 percent of any bonus bid for the use and benefit of the Indian mineral owner.

(6) If no satisfactory bid is received, or if the accepted bidder fails to complete all requirements necessary for the approval of the lease, or if the Secretary determines that it is not in the best interest of the Indian mineral owner to accept any of the bids the Secretary may re-advertise the lease for sale, or, subject to the consent of the Indian mineral owner, the lease may be let through private negotiations.

(c) The Secretary shall advise the Indian mineral owner of the results of the bidding, and shall not approve the lease until the consent of the Indian mineral owner has been obtained.

(d) The Indian mineral owner may also submit negotiated leases to the Secretary for review and approval.

**§ 211.21 [Reserved]**



[top](#)

**§ 211.22 Leases for subsurface storage of oil or gas.**



[top](#)

(a) The Secretary, with the consent of the Indian mineral owners, may approve storage leases, or modifications, amendments, or extensions of existing leases, on Indian lands to provide for the subsurface storage of oil or gas, irrespective of the lands from which production is initially obtained. The storage lease, or modification, amendment, or extension to an existing lease, shall provide for the payment of such storage fee or rental on such oil or gas as may be determined adequate in each case, or, in lieu thereof, for a royalty other than that prescribed in the oil and gas lease when such stored oil and gas is produced in conjunction with oil or gas not previously produced.

(b) The Secretary, with consent of the Indian mineral owners, may approve a provision in an oil and gas lease under which storage of oil and gas is authorized, for continuance of the lease at least for the period of such storage use and so long thereafter as oil or gas not previously produced is produced in paying quantities.

(c) Applications for subsurface storage of oil or gas shall be filed in triplicate with the authorized officer and shall disclose the ownership of the lands involved, the parties in interest, the storage fee, rental, or royalty offered to be paid for such storage, and all essential information showing the necessity for such project. Enough copies of the final agreement signed by the Indian mineral owners and other parties in interest shall be submitted for the approval of the Secretary to permit retention of five copies by the Department after approval.

**§ 211.23 Corporate qualifications and requests for information.**



[top](#)

(a) The signing in a representative capacity and delivery of bids, geological and geophysical permits, mineral leases, or assignments, bonds, or other instruments required by the regulations in this part constitutes certification that the individual signing (except a surety agent) is authorized to act in such capacity. An agent for a surety shall furnish a power of attorney.

(b) A corporate applicant proposing to acquire an interest in a permit or lease shall have on file with the superintendent or area director a statement showing:

(1) The State(s) in which the corporation is incorporated, and that the corporation is authorized to hold such interests in the State where the land described in the instrument is situated; and

(2) A notarized statement that the corporation has power to conduct all business and operations as described in the lease or permit.

(c) The Secretary may, either before or after the approval of a permit, mineral lease, assignment, or bond, call for any reasonable additional information necessary to carry out the regulations in this part, or other applicable laws and regulations.

**§ 211.24 Bonds.**



[top](#)

(a) The lessee, permittee or prospective lessee acquiring a lease, or any interest therein, by assignment shall furnish with each lease, permit or assignment a surety bond or personal bond in an amount sufficient to ensure compliance with all of the terms and conditions of the lease(s), permit(s), or assignment(s) and the statutes and regulations applicable to the lease, permit, or assignment. Surety bonds shall be issued by a qualified company approved by the Department of the Treasury (see Department of the Treasury Circular No. 570).

(b) An operator may file a \$75,000 bond for all geothermal, mining, or oil and gas leases, permits, or assignments in any one State, which may also include areas on that part of an Indian reservation

extending into any contiguous State. Statewide bonds are subject to approval in the discretion of the Secretary.

(c) An operator may file a \$150,000 bond for full nationwide coverage to cover all geothermal or oil and gas leases, permits, or assignments without geographic or acreage limitation to which the operator is or may become a party. Nationwide bonds are subject to approval in the discretion of the Secretary.

(d) Personal bonds shall be accompanied by:

(1) Certificate of deposit issued by a financial institution, the deposits of which are federally insured, explicitly granting the Secretary full authority to demand immediate payment in case of default in the performance of the provisions and conditions of the lease or permit. The certificate shall explicitly indicate on its face that Secretarial approval is required prior to redemption of the certificate of deposit by any party;

(2) Cashier's check;

(3) Certified check;

(4) Negotiable Treasury securities of the United States of a value equal to the amount specified in the bond. Negotiable Treasury securities shall be accompanied by a proper conveyance to the Secretary of full authority to sell such securities in case of default in the performance of the provisions and conditions of a lease or permit; or

(5) Letter of credit issued by a financial institution authorized to do business in the United States and whose deposits are federally insured, and identifying the Secretary as sole payee with full authority to demand immediate payment in the case of default in the performance of the provisions and conditions of a lease or permit.

(i) The letter of credit shall be irrevocable during its term.

(ii) The letter of credit shall be payable to the Bureau of Indian Affairs upon demand, in part or in full, upon receipt from the Secretary of a notice of attachment stating the basis thereof (e.g., default in compliance with the lease or permit provisions and conditions or failure to file a replacement in accordance with paragraph (d)(5)(v) of this section).

(iii) The initial expiration date of the letter of credit shall be at least one (1) year following the date it is filed in the proper Bureau of Indian Affairs office.

(iv) The letter of credit shall contain a provision for automatic renewal for periods of not less than one (1) year in the absence of notice to the proper Bureau of Indian Affairs office at least ninety (90) days prior to the originally stated or any extended expiration date.

(v) A letter of credit used as security for any lease or permit upon which operations have taken place and final approval for abandonment has not been given, or as security for a statewide or nationwide bond, shall be forfeited and shall be collected by the Secretary if not replaced by other suitable bond or letter of credit at least thirty (30) days before its expiration date.

(e) The required amount of bonds may be increased in any particular case at the discretion of the Secretary.

#### **§ 211.25 Acreage limitation.**



[top](#)

A lessee may acquire more than one lease but no single lease shall be granted for mineral leasing purposes on Indian tribal or restricted lands in excess of the following acreage except where the rule of approximation applies:

(a) Leases for oil and gas and all other minerals except coal are to be contained within one United States Governmental survey section of land and shall be described by legal subdivisions including lots or tract equivalents not to exceed 640 acres; in instances of irregular surveys, including lands not surveyed under the United States Governmental survey, lands shall be considered in multiples of 40 acres or the nearest aliquot equivalent thereof;

(b) Leases for coal shall ordinarily be limited to 2,560 acres in a reasonably compact form and shall be described by legal subdivisions including lots or tract equivalents. In instances of irregular surveys, including lands not surveyed under the United States Governmental survey, lands shall be considered in multiples of 40 acres or the nearest aliquot equivalent thereof. The Secretary may, upon application and with the consent of the Indian mineral owner, approve the issuance of a single lease for more than 2,560 acres, in a reasonably compact form, upon a finding that the issuance is in the best interest of the lessor.

#### § 211.26 [Reserved]



#### § 211.27 Duration of leases.



(a) All leases shall be for a term not to exceed a primary term of lease duration of ten (10) years and, absent specific lease provisions to the contrary, shall continue as long thereafter as the minerals specified in the lease are produced in paying quantities. Absent specific lease provisions to the contrary, all provisions in leases governing their duration shall be measured from the date of approval by the Secretary.

(b) An oil and gas or geothermal resource lease which stipulates that it shall continue in full force and effect beyond the expiration of the primary term of lease duration ("commencement clause") if drilling operations have commenced during the primary term, shall be valid and shall hold the lease beyond the primary term of lease duration if the lessee or the lessee's designee has commenced actual drilling by midnight of the last day of the primary term of the lease with a drilling rig designed to reach the total proposed depth, and drilling is continued with reasonable diligence until the well is completed to production or abandoned. However, in no case shall such drilling hold the lease longer than 120 days past the primary term of lease duration without actual production of oil, gas, or geothermal resources. *Provided*, that this extension does not allow a lease to continue past the 10-year statutory limitation. Drilling which meets the requirements of this section and occurs within a unit or communitization agreement to which the lease is committed shall be considered as if it occurs on the leasehold itself. If there is a conflict between the commencement clause and the habendum clause of a lease, the commencement clause will control.

(c) A solid minerals lease which stipulates that it shall continue in full force and effect beyond the expiration of the primary term of lease duration if mining operations have commenced during the primary term (commencement clause), shall be valid and hold the lease beyond the primary term of lease duration if the lessee or the lessee's designee has by midnight of the last day of the primary term of the lease commenced actual removal of mineral materials intended for sale and upon which royalties will be paid. If there is a conflict between the commencement clause and the habendum clause of a lease, the commencement clause will control.

#### § 211.28 Unitization and communitization agreements, and well spacing.



(a) For the purpose of promoting conservation and efficient utilization of minerals, the Secretary may approve a cooperative unit, drilling or other development plan on any leased area upon a determination that approval is advisable and in the best interest of the Indian mineral owner. For the purposes of this section, a cooperative unit, drilling or other development plan means an agreement for the development or operation of a specifically designated area as a single unit without regard to separate ownership of the land included in the agreement. Such cooperative agreements include, but are not limited to, unit agreements, communitization agreements and other types of agreements that allocate costs and benefits.

(b) The consent of the Indian mineral owner to such unit or cooperative agreement shall not be required unless such consent is specifically required in the lease. However, the Secretary shall consult with the Indian mineral owner prior to making a determination concerning a cooperative agreement or well spacing plan.

(c) Requests for approval of cooperative agreements which comply with the requirements of all applicable rules and regulations shall be filed with the superintendent or area director.

(d) All Indian mineral owners of any right, title or interest in the mineral resources to be included in a

cooperative agreement must be notified by the lessee at the time the agreement is submitted to the superintendent or area director. An affidavit from the lessee stating that a notice was mailed to each mineral owner of record for whom the superintendent or area director has an address will satisfy this notice requirement.

(e) A request for approval of a proposed cooperative agreement, and all documents incident to such agreement, must be filed with the superintendent or area director at least ninety (90) days prior to the first expiration date of any of the Indian leases in the area proposed to be covered by the cooperative agreement.

(f) Unless otherwise provided in the cooperative agreement, approval of the agreement commits each lease to the unit in the area covered by the agreement on the date approved by the Secretary or the date of first production, whichever is earlier, as long as the agreement is approved before the lease expiration date.

(g) Any lease committed in part to any such cooperative agreement shall be segregated into a separate lease or leases as to the lands committed and lands not committed to the agreement. Segregation shall be effective on the date the agreement is effective.

(h) Wells shall be drilled in conformity with a well spacing program approved by the authorized officer.

#### **§ 211.29 Exemption of leases and permits made by organized tribes.**



[top](#)

The regulations in this part may be superseded by the provisions of any tribal constitution, bylaw or charter issued pursuant to the Indian Reorganization Act of June 18, 1934 (48 Stat. 984; 25 U.S.C. 461–479), the Alaska Act of May 1, 1936 (49 Stat. 1250; 48 U.S.C. 362,258a), or the Oklahoma Indian Welfare Act of June 26, 1936 (49 Stat. 1967; 25 U.S.C., and Sup., 501–509), or by ordinance, resolution, or other action authorized under such constitution, bylaw or charter; Provided, that such tribal law may not supersede the requirements of Federal statutes applicable to Indian mineral leases. The regulations in this part, in so far as they are not so superseded, shall apply to leases and permits made by organized tribes if the validity of the lease or permit depends upon the approval of the Secretary of the Interior.

#### **Subpart C—Rents, Royalties, Cancellations and Appeals**



[top](#)

#### **§ 211.40 Manner of payments.**



[top](#)

Unless otherwise specifically provided for in a lease, once production has been established, all payments shall be made to the MMS or such other party as may be designated, and shall be made at such time as provided in 30 CFR chapter II, subchapters A and C. Prior to production, all bonus and rental payments, shall be made to the superintendent or area director.

#### **§ 211.41 Rentals and production royalty on oil and gas leases.**



[top](#)

(a) A lessee shall pay, in advance, beginning with the effective date of the lease, an annual rental of \$2.00 per acre or fraction of an acre or such other greater amount as prescribed in the lease. This rental shall not be credited against production royalty nor shall the rental be prorated or refunded because of surrender or cancellation.

(b) The Secretary shall not approve leases with a royalty rate less than 16–2/3 percent of the amount or value of production produced and sold from the lease unless a lower royalty rate is agreed to by the Indian mineral owner and is found to be in the best interest of the Indian mineral owner. Such approval may only be granted by the area director if the approving official is the superintendent and by the Assistant Secretary for Indian Affairs if the approving official is the area director.

(c) Value of lease production for royalty purposes shall be determined in accordance with applicable lease provisions and regulations in 30 CFR chapter II, subchapters A and C. If the valuation provisions in the lease are inconsistent with the regulations in 30 CFR chapter II, subchapters A and C, the lease provisions shall govern.

(d) If the leased premises produce gas in excess of the lessee's requirements for the development and operation of said premises, then the lessor may use sufficient gas, free of charge, for any desired school or other buildings belonging to the tribe, by making his own connections to a regulator installed, connected to the well and maintained by the lessee, and the lessee shall not be required to pay royalty on gas so used. The use of such gas shall be at the lessor's risk at all times.

**§ 211.42 Annual rentals and expenditures for development on leases other than oil and gas, and geothermal resources.**



[top](#)

(a) Unless otherwise authorized by the Secretary, a lease for minerals other than oil, gas and geothermal resources shall provide for a yearly development expenditure of not less than \$20 per acre. All such leases shall provide for a rental payment of not less than \$2.00 for each acre or fraction of an acre payable on or before the first day of each lease year.

(b) Within twenty (20) days after the lease year, an itemized statement, in duplicate, of the expenditure for development under a lease for minerals other than oil and gas shall be filed with the superintendent or area director. The lessee must certify the statement under oath.

**§ 211.43 Royalty rates for minerals other than oil and gas.**



[top](#)

(a) Except as provided in paragraph (b) of this section, the minimum rates for leases of minerals other than oil and gas shall be as follows:

(1) For substances other than coal, the royalty rate shall be 10 percent of the value of production produced and sold from the lease at the nearest shipping point.

(2) For coal to be strip or open pit mined the royalty rate shall be 12 1/2 percent of the value of production produced and sold from the lease, and for coal removed from an underground mine, the royalty rate shall be 8 percent of the value of production produced and sold from the lease.

(3) For geothermal resources, the royalty rate shall be 10 percent of the amount or value of steam, or any other form of heat or energy derived from production of geothermal resources under the lease and sold or utilized by the lessee. In addition, the royalty rate shall be 5 percent of the value of any byproduct derived from production of geothermal resources under the lease and sold or utilized or reasonably susceptible of sale or utilization by the lessee, except that the royalty for any mineral byproduct shall be governed by the appropriate paragraph of this section.

(b) A lower royalty rate shall be allowed if it is determined to be in the best interest of the Indian mineral owner. Approval of a lower rate may only be granted by the area director if the approving official is the superintendent or by the Assistant Secretary for Indian Affairs, if the approving official is the area director.

**§ 211.44 Suspension of operations.**



[top](#)

(a) After the expiration of the primary term of the lease the Secretary may approve suspension of operations for remedial purposes which are necessary for continued production, to protect the resource, the environment, or for other good reasons. *Provided*, that such remedial operations are conducted in accordance with 43 CFR part 3160, subpart 3165 and under such stipulations and conditions as may be prescribed by the Secretary and are conducted with reasonable diligence. Any suspension shall not relieve the lessee from liability for the payment of rental and other payments as required by lease provisions.

(b) An application for permission to suspend operations or production for economic or marketing reasons

on a lease capable of production after the expiration of the primary term of lease duration must be accompanied by the written consent of the Indian mineral owner, an economic analysis, and an executed amendment by the parties to the lease setting forth the provisions pertaining to the suspension of operations and production. Such application shall be treated as a negotiated change to lease provisions, and as such, shall be subject to review and approval by the Secretary.

**§ 211.45 [Reserved]**



**§ 211.46 Inspection of premises, books and accounts.**



Lessees shall allow the Indian mineral owner, the Indian mineral owner's representatives, or any authorized representative of the Secretary to enter all parts of the leased premises for the purpose of inspection and audit. Lessees shall keep a full and correct account of all operations and submit all related reports required by the lease and applicable regulations. Books and records shall be available for inspection during regular business hours.

**§ 211.47 Diligence, drainage and prevention of waste.**



The lessee shall:

- (a) Exercise diligence in mining, drilling and operating wells on the leased lands while minerals production can be secured in paying quantities;
- (b) Protect the lease from drainage (if oil and gas or geothermal resources are being drained from the lease premises by a well or wells located on lands not included in the lease, the Secretary reserves the right to impose reasonable and equitable terms and conditions to protect the interest of the Indian mineral owner of the lands, such as payment of compensatory royalty for the drainage);
- (c) Carry on operations in a good and workmanlike manner in accordance with approved methods and practices;
- (d) Have due regard for the prevention of waste of oil or gas or other minerals, the entrance of water through wells drilled by the lessee to other strata, to the destruction or injury of the oil or gas, other mineral deposits, or fresh water aquifers, the preservation and conservation of the property for future productive operations, and the health and safety of workmen and employees;
- (e) Securely plug all wells and effectively shut off all water from the oil or gas-bearing strata before abandoning them;
- (f) Not construct any well pad location within 200 feet of any structures or improvements without the Indian surface owner's written consent;
- (g) Carry out, at the lessee's expense, all reasonable orders and requirements of the authorized officer relative to prevention of waste;
- (h) Bury all pipelines crossing tillable lands below plow depth unless other arrangements are made with the Indian surface owner; and
- (i) Pay the Indian surface owner all damages, including damages to crops, buildings, and other improvements of the Indian surface owner occasioned by the lessee's operations as determined by the superintendent.

**§ 211.48 Permission to start operations.**



(a) No exploration, drilling, or mining operations are permitted on any Indian lands before the Secretary has granted written approval of a mineral lease or permit pursuant to the regulations in this part.

(b) After a lease or permit is approved, written permission must be secured from the Secretary before any operations are started on the leased premises, in accordance with applicable rules and regulations in 25 CFR part 216; 30 CFR chapter II, subchapters A and C; 30 CFR part 750 (Requirements for Surface Coal Mining and Reclamation Operations on Indian Lands), 43 CFR parts 3160, 3260, 3480, 3590, and Orders or Notices to Lessees (NTLs) issued thereunder.

#### § 211.49 Restrictions on operations.



[top](#)

Leases issued under the provisions of the regulations in this part shall be subject to such restrictions as to time or times for well operations and production from any leased premises as the Secretary judges may be necessary or proper for the protection of the natural resources of the leased land and in the interest of the lessor.

#### § 211.50 [Reserved]



[top](#)

#### § 211.51 Surrender of leases.



[top](#)

A lessee may, with the approval of the Secretary, surrender a lease or any part of it, on the following conditions:

(a) All royalties and rentals due on the date the request for surrender is received must be paid;

(b) The superintendent, after consultation with the authorized officer, must be satisfied that proper provisions have been made for the conservation and protection of the property, and that all operations on the portion of the lease surrendered have been properly reclaimed, abandoned, or conditioned, as required;

(c) If a lease has been recorded, the lessee must submit a release along with the recording information of the original lease so that, after acceptance of the release, it may be recorded;

(d) If a lessee requests to surrender an entire lease or an entire undivided portion of a lease document, the lessee must deliver to the superintendent or area director the original lease documents; *Provided*, that where the request is made by an assignee to whom no copy of the lease was delivered, the assignee must deliver to the superintendent or area director only its copy of the assignment;

(e) If the lease (or a portion thereof being surrendered) is owned in undivided interests, all lessees owning undivided interests in the lease must join in the request for surrender;

(f) No part of any advance rental shall be refunded to the lessee, nor shall any subsequent surrender or termination of a lease relieve the lessee of the obligation to pay advance rental if advance rental became due prior to the date the request for surrender was received by the superintendent or area director;

(g) If oil, gas, or geothermal resources are being drained from the leased premises by a well or wells located on lands not included in the lease, the Secretary reserves the right, prior to acceptance of the surrender, to impose reasonable and equitable terms and conditions to protect the interests of the Indian mineral owners of the lands surrendered. Such terms and conditions may include payment of compensatory royalty for any drainage; and

(h) Upon expiration or surrender of a solid mineral lease the lessee shall deliver the leased premises in a condition conforming to the approved reclamation plan. Unless otherwise provided in the lease, the machinery necessary to operate the mine is the property of the lessee. However, the machinery may not be removed from the leased premises without the written permission of the Secretary.

## **§ 211.52 Fees.**



Unless otherwise authorized by the Secretary, each permit, lease, sublease, or other contract, or assignment, thereof shall be accompanied by a filing fee of \$75.00 at the time of filing.

## **§ 211.53 Assignments, overriding royalties, and operating agreements.**



(a) Approved leases or any interest therein may be assigned or transferred only with the approval of the Secretary. The Indian mineral owner must also consent if approval of the Indian mineral owner is required in the lease. If consent is not required, then the Secretary shall notify the Indian mineral owner of the proposed assignment. To obtain the approval of the Secretary the assignee must be qualified to hold the lease under existing rules and regulations and shall furnish a satisfactory bond conditioned for the faithful performance of the covenants and conditions of the lease.

(b) No lease or interest therein or the use of such lease shall be assigned, sublet, or transferred, directly or indirectly, by working or drilling contract, or otherwise, without the consent of the Secretary.

(c) Assignments of leases, and stipulations modifying the provisions of existing leases, which stipulations are also subject to the approval of the Secretary, shall be filed with the superintendent within five (5) working days after the date of execution. Upon execution of satisfactory bonds by the assignee the Secretary may permit the release of any bonds executed by the assignor. Upon execution of satisfactory bonds the assignee accepts all the assignor's responsibilities and prior obligations and liabilities of the assignor (including but not limited to any underpaid royalties and rentals) under the lease.

(d) Agreements creating overriding royalties or payments out of production shall not be considered as interests in the leases as such provision is used in this section. Agreements creating overriding royalties or payments out of production, or agreements designating operators are hereby authorized and the approval of the Secretary shall not be required with respect thereto, but such agreements shall be subject to the condition that nothing in such agreements shall be construed as modifying any of the obligations of the lessee, including, but not limited to, obligations imposed by requirements of the MMS for reporting, accounting, and auditing; obligations for diligent development and operation, protection against drainage and mining in trespass, compliance with oil and gas, geothermal, and mining regulations (25 CFR part 216; 43 CFR parts 3160, 3260, 3480, and 3590; and those applicable rules found in 30 CFR chapter II, subchapters A and C) and the requirements for Secretarial approval before abandonment of any oil and gas or geothermal well or mining operation. All such obligations are to remain in full force and effect, the same as if free of any such overriding royalties or payments. The existence of agreements creating overriding royalties or payments out of production, whether or not actually paid, shall not be considered as justification for the approval of abandonment of any oil and gas or geothermal well or mining operation. Nothing in this paragraph revokes the requirement for approval of assignments and other instruments which is required in this section, but any overriding royalties or payments out of production created by the provisions of such assignments or instruments shall be subject to the condition stated in this section. Agreements creating overriding royalties or payments out of production, or agreements designating operators shall be filed with the superintendent unless incorporated in assignments or instruments required to be filed pursuant to this section.

## **§ 211.54 Lease or permit cancellation; Bureau of Indian Affairs notice of noncompliance.**



(a) If the Secretary determines that a permittee or lessee has failed to comply with the terms of the permit or lease; the regulations in this part; or other applicable laws or regulations; the Secretary may:

(1) Serve a notice of noncompliance specifying in what respect the permittee or lessee has failed to comply with the requirements referenced in this paragraph, and specifying what actions, if any, must be taken to correct the noncompliance; or

(2) Serve a notice of proposed cancellation of the lease or permit. The notice of proposed cancellation shall set forth the reasons why lease or permit cancellation is proposed and shall specify what actions, if any, must be taken to avoid cancellation.

(b) The notice of noncompliance or proposed cancellation shall specify in what respect the permittee or lessee has failed to comply with the requirements referenced in paragraph (a), and shall specify what actions, if any, must be taken to correct the noncompliance.

(c) The notice shall be served upon the permittee or lessee by delivery in person or by certified mail to the permittee or lessee at the permittee's or lessee's last known address. When certified mail is used, the date of service shall be deemed to be when the notice is received or five (5) working days after the date it is mailed, whichever is earlier.

(d) The lessee or permittee shall have thirty (30) days (or such longer time as specified in the notice) from the date that the notice is served to respond, in writing, to the official or the Bureau of Indian Affairs office that issued the notice.

(e) If a permittee or lessee fails to take any action that is prescribed in the notice of proposed cancellation, fails to file a timely written response to the notice, or files a written response that does not, in the discretion of the Secretary, adequately justify the permittee's or lessee's actions, then the Secretary may cancel the lease or permit, specifying the basis for the cancellation.

(f) If a permittee or lessee fails to take corrective action or to file a timely written response adequately justifying the permittee's or lessee's actions pursuant to a notice of noncompliance, the Secretary may issue an order of cessation of operations. If the permittee or lessee fails to comply with the order of cessation, or fails to timely file an appeal of the order of cessation pursuant to paragraph (h), the Secretary may issue an order of lease or permit cancellation.

(g) Cancellation of a lease or permit shall not relieve the lessee or permittee of any continuing obligations under the lease or permit.

(h) Orders of cessation or of lease or permit cancellation issued pursuant to this section may be appealed under 25 CFR part 2.

(i) This section does not limit any other remedies of the Indian mineral owner as set forth in the lease or permit.

(j) Nothing in this section is intended to limit the authority of the authorized officer or the MMS official to take any enforcement action authorized pursuant to statute or regulation.

(k) The authorized officer, MMS official, and the superintendent and/or area director should consult with one another before taking any enforcement actions.

#### **§ 211.55 Penalties.**



[top](#)

(a) In addition to or in lieu of cancellation under §211.54, violations of the terms and conditions of any lease, or the regulations in this part, or failure to comply with a notice of noncompliance or a cessation order issued by the Secretary, or, in the case of solid minerals the authorized officer, may subject a lessee or permittee to a penalty of not more than \$1,000 per day for each day that such a violation or noncompliance continues beyond the time limits prescribed for corrective action.

(b) A notice of a proposed penalty shall be served on the lessee or permittee either personally or by certified mail to the lessee or permittee at the lessee's or permittee's last known address. The date of service by certified mail shall be deemed to be the date when received or five (5) working days after the date mailed, whichever is earlier.

(c) The notice shall specify the nature of the violation and the proposed penalty, and shall specifically advise the lessee or permittee of the lessee's or permittee's right to either request a hearing within thirty (30) days from receipt of the notice or pay the proposed penalty. Hearings shall be held before the superintendent and/or area director whose findings shall be conclusive, unless an appeal is taken pursuant to 25 CFR part 2.

(d) If the lessee or permittee served with a notice of proposed penalty requests a hearing, penalties shall accrue each day the violations or noncompliance set forth in the notice continue beyond the time limits prescribed for corrective action. The Secretary may issue a written suspension of the requirement to correct the violations pending completion of the hearings provided by this section only upon a determination, at the discretion of the Secretary, that such a suspension will not be detrimental to the lessor and upon submission and acceptance of a bond deemed adequate to indemnify the lessor from

loss or damage. The amount of the bond must be sufficient to cover the cost of correcting the violations set forth in the notice or any disputed amounts plus accrued penalties and interest.

(e) Payment in full of penalties more than ten (10) days after a final decision imposing a penalty shall subject the lessee or permittee to late payment charges. Late payment charges shall be calculated on the basis of a percentage assessment rate of the amount unpaid per month for each month or fraction thereof until payment is received by the Secretary. In the absence of a specific lease provision prescribing a different rate, the interest rate on late payments and underpayments shall be a rate applicable under §6621(a)(2) of the Internal Revenue Code of 1954. Interest shall be charged only on the amount of payment not received and only for the number of days the payment is late.

(f) None of the provisions of this section shall be interpreted as:

(1) Replacing or superseding the independent authority of the authorized officer, the director's representative or the MMS official to impose penalties for violations of applicable regulations pursuant to 43 CFR part 3160, and 43 CFR Groups 3400 and 3500, 30 CFR part 750, or 30 CFR chapter II, subchapters A and C;

(2) Replacing or superseding any penalty provision in the terms and conditions of a lease or permit approved by the Secretary pursuant to this part; or

(3) Authorizing the imposition of a penalty for violations of lease or permit terms for which the authorized officer, director's representative or MMS official, have either statutory or regulatory authority to assess a penalty.

#### **§ 211.56 Geological and geophysical permits.**



[top](#)

Permits to conduct geological and geophysical operations on Indian lands which do not conflict with any mineral leases entered into pursuant to this part, may be approved by the Secretary with the consent of the Indian mineral owner under the following conditions:

(a) The permit must describe the area to be explored, the duration, and the consideration to be paid the Indian owner;

(b) The permit will not grant the permittee any option or preference rights to a lease or other development contract, or authorize the production of, or removal of oil and gas, geothermal resources, or other minerals, except samples for assay and experimental purposes, unless specifically so stated in the permit; and

(c) Copies of all data collected pursuant to operations conducted under the permit shall be forwarded to the Secretary and the Indian mineral owner, unless otherwise provided in the permit. Data collected under a permit may be held by the Secretary as privileged and proprietary information for the time prescribed in the permit. Where no time period is prescribed in the permit, the Secretary may release such information after six (6) years, with the consent of the Indian mineral owner.

#### **§ 211.57 Forms.**



[top](#)

Leases, bonds, permits, assignments, and other instruments relating to mineral leasing shall be on forms, prescribed by the Secretary, that may be obtained from the superintendent or area director. The provisions of a standard lease or permit may be changed, deleted, or added to by written agreement of all parties with the approval of the Secretary.

#### **§ 211.58 Appeals.**



[top](#)

Appeals from decisions of Bureau of Indian Affairs officers under this part may be taken pursuant to 25 CFR part 2.

[Browse Previous](#) | [Browse Next](#)

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[Home Page](#) > [Executive Branch](#) > [Code of Federal Regulations](#) > [Electronic Code of Federal Regulations](#)

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### **Title 25: Indians**

[Browse Previous](#) | [Browse Next](#)

## **PART 224—TRIBAL ENERGY RESOURCE AGREEMENTS UNDER THE INDIAN TRIBAL ENERGY DEVELOPMENT AND SELF DETERMINATION ACT**

### **Section Contents**

#### **Subpart A—General Provisions**

- [§ 224.10 What is the purpose of this part?](#)
- [§ 224.20 How will the Secretary interpret and implement this part and the Act?](#)
- [§ 224.30 What definitions apply to this part?](#)
- [§ 224.40 How does the Act or a TERA affect the Secretary's trust responsibility?](#)
- [§ 224.41 When does the Secretary require agreement of more than one tribe to approve a TERA?](#)
- [§ 224.42 How does the Paperwork Reduction Act affect these regulations?](#)

#### **Subpart B—Procedures for Obtaining Tribal Energy Resource Agreements**

- [§ 224.50 What is the purpose of this subpart?](#)

#### **Pre-application Consultation and the Form of Application**

- [§ 224.51 What is a pre-application consultation between a tribe and the Director?](#)
- [§ 224.52 What may a tribe include in a TERA?](#)
- [§ 224.53 What must an application for a TERA contain?](#)

#### **Processing Applications**

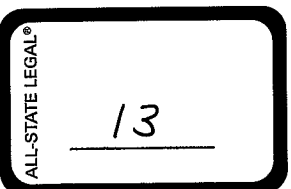
- [§ 224.54 How must a tribe submit an application?](#)
- [§ 224.55 Is information a tribe submits throughout the TERA process under this part subject to disclosure to third parties?](#)
- [§ 224.56 What is the effect of the Director's receipt of a tribe's complete application?](#)
- [§ 224.57 What must the Director do upon receipt of an application?](#)

#### **Application Consultation Meeting**

- [§ 224.58 What is an application consultation meeting?](#)
- [§ 224.59 How will the Director use the results of the application consultation meeting?](#)
- [§ 224.60 What will the Director provide to the tribe after the application consultation meeting?](#)
- [§ 224.61 What will the tribe provide to the Director after receipt of the Director's report on the application consultation meeting?](#)
- [§ 224.62 May a final proposed TERA differ from the original proposed TERA?](#)

#### **TERA Requirements**

- [§ 224.63 What provisions must a TERA contain?](#)
- [§ 224.64 How may a tribe assume management of development of different types of energy resources?](#)
- [§ 224.65 How may a tribe assume additional activities under a TERA?](#)
- [§ 224.66 How may a tribe reduce the scope of the TERA?](#)



### **Public Notification and Comment**

§ 224.67 What must the Secretary do upon the Director's receipt of a final proposed TERA?

§ 224.68 How will the Secretary use public comments?

### **Subpart C—Approval of Tribal Energy Resource Agreements**

§ 224.70 Will the Secretary review a proposed TERA under the National Environmental Policy Act?

§ 224.71 What standards will the Secretary use to decide to approve a final proposed TERA?

§ 224.72 How will the Secretary determine whether a tribe has demonstrated sufficient capacity?

§ 224.73 How will the scope of energy resource development affect the Secretary's determination of the tribe's capacity?

§ 224.74 When must the Secretary approve or disapprove a final proposed TERA?

§ 224.75 What must the Secretary do upon approval or disapproval of a final proposed TERA?

§ 224.76 Upon notification of disapproval, may a tribe re-submit a revised final proposed TERA?

§ 224.77 Who may appeal the Secretary's decision on a final proposed TERA or a revised final proposed TERA?

### **Subpart D—Implementation of Tribal Energy Resource Agreements**

#### **Applicable Authorities and Responsibilities**

§ 224.80 Under what authority will a tribe perform activities for energy resource development?

§ 224.81 What laws are applicable to activities?

§ 224.82 What activities will the Department continue to perform after approval of a TERA?

#### **Leases, Business Agreements, and Rights-of-Way Under a TERA**

§ 224.83 What must a tribe do after executing a lease or business agreement, or granting a right-of-way?

§ 224.84 When may a tribe grant a right-of-way?

§ 224.85 When may a tribe enter into a lease or business agreement?

§ 224.86 Are there limits on the duration of leases, business agreements, and rights-of-way?

#### **Violation or Breach**

§ 224.87 What are the obligations of a tribe if it discovers a violation or breach?

§ 224.88 What must the Director do after receiving notice of a violation or breach from the tribe?

§ 224.89 What procedures will the Secretary use to enforce leases, business agreements, or rights-of-way?

### **Subpart E—Interested Party Petitions**

§ 224.100 May a person or entity ask the Secretary to review a tribe's compliance with a TERA?

§ 224.101 Who is an interested party?

§ 224.102 Must a tribe establish a comment or hearing process for addressing environmental concerns?

§ 224.103 Must a tribe establish other public participation processes?

§ 224.104 Must a tribe enact tribal laws, regulations, or procedures permitting a person or entity to allege that a tribe is not complying with a TERA?

§ 224.105 How may a person or entity obtain copies of tribal laws, regulations, or procedures that would permit an allegation of noncompliance with a TERA?

§ 224.106 If a tribe has enacted tribal laws, regulations, or procedures for challenging tribal action, how must the tribe respond to a petition?

§ 224.107 What must a petitioner do before filing a petition with the Secretary?

§ 224.108 May tribes offer a resolution of a petitioner's claim?

§ 224.109 What must a petitioner claim or request in a petition filed with the Secretary?

§ 224.110 What must a petition to the Secretary contain?

§ 224.111 When may a petitioner file a petition with the Secretary?

§ 224.112 What must the Director do upon receipt of a petition?

- § 224.113 What must the tribe do after it completes petition consultation with the Director?
- § 224.114 How may the tribe address a petition in its written response?
- § 224.115 When in the petition process must the Director investigate a tribe's compliance with a TERA?
- § 224.116 What is the time period in which the Director must investigate a tribe's compliance with a TERA?
- § 224.117 Must the Director make a determination of the tribe's compliance with a TERA?
- § 224.118 How must the tribe respond to the Director's notice of the opportunity for a hearing?
- § 224.119 What must the Director do when making a decision on a petition?
- § 224.120 What action may the Director take to ensure compliance with a TERA?
- § 224.121 How may a tribe or a petitioner appeal the Director's decision about the tribe's compliance with the TERA?

#### **Subpart F—Periodic Reviews**

- § 224.130 What is the purpose of this subpart?
- § 224.131 What is a periodic review and evaluation?
- § 224.132 How does the Director conduct a periodic review and evaluation?
- § 224.133 What must the Director do after a periodic review and evaluation?
- § 224.134 How often must the Director conduct a periodic review and evaluation?
- § 224.135 Under what circumstances may the Director conduct additional reviews and evaluations?

#### **Noncompliance**

- § 224.136 How will the Director's report address a tribe's noncompliance?
- § 224.137 What must the Director do if a tribe's noncompliance has resulted in harm or the potential for harm to a physical trust asset?
- § 224.138 What must the Director do if a tribe's noncompliance has caused imminent jeopardy to a physical trust asset?
- § 224.139 What must a tribe do after receiving a notice of imminent jeopardy to a physical trust asset?
- § 224.140 What must the Secretary do if the tribe fails to respond to or does not comply with the Director's order?
- § 224.141 What must the Secretary do if the tribe responds to the Director's order?

#### **Subpart G—Reassumption**

- § 224.150 What is the purpose of this subpart?
- § 224.151 When may the Secretary reassume activities?
- § 224.152 Must the Secretary always reassume the activities upon a finding of imminent jeopardy to a physical trust asset?

#### **Notice of Intent To Reassume**

- § 224.153 Must the Secretary notify the tribe of an intent to reassume the authority granted?
- § 224.154 What must a notice of intent to reassume include?
- § 224.155 When must a tribe respond to a notice of intent to reassume?
- § 224.156 What information must the tribe's response to the notice of intent to reassume include?
- § 224.157 How must the Secretary proceed after receiving the tribe's response?
- § 224.158 What must the Secretary include in a written notice of reassumption?
- § 224.159 How will reassumption affect valid existing rights or lawful actions taken before the effective date of the reassumption?
- § 224.160 How will reassumption affect a TERA?
- § 224.161 How may reassumption affect the tribe's ability to enter into a new TERA or to modify another TERA to administer additional activities or to assume administration of activities that the Secretary previously reassumed?

#### **Subpart H—Rescission**

- § 224.170 What is the purpose of this subpart?
- § 224.171 Who may rescind a TERA?
- § 224.172 May a tribe rescind only some of the activities subject to a TERA while retaining a portion of those activities?
- § 224.173 How does a tribe rescind a TERA?
- § 224.174 When does a voluntary rescission become effective?

§ 224.175 How will rescission affect valid existing rights or lawful actions taken before the rescission?

### **Subpart I—General Appeal Procedures**

§ 224.180 What is the purpose of this subpart?

§ 224.181 Who may appeal Departmental decisions or inaction under this part?

§ 224.182 What is the Initial Appeal Process?

§ 224.183 What other administrative appeals processes also apply?

§ 224.184 How do other administrative appeals processes apply?

§ 224.185 When are decisions under this part effective?

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**Authority:** 25 U.S.C. 2 and 9; 25 U.S.C. 3501–3504; Pub. L. 109–58

**Source:** 73 FR 12821, Mar. 10, 2008, unless otherwise noted.

### **Subpart A—General Provisions**



[top](#)

#### **§ 224.10 What is the purpose of this part?**



[top](#)

This part:

(a) Establishes procedures by which a tribe, at its discretion, may enter into and manage leases, business agreements, and rights-of-way for purposes of energy resource development on tribal land; and

(b) Describes the process for obtaining, implementing, and enforcing a tribal energy resource agreement (TERA) that will allow a tribe to enter into individual leases, business agreements, and rights-of-way without obtaining Secretarial approval.

#### **§ 224.20 How will the Secretary interpret and implement this part and the Act?**



[top](#)

(a) The Secretary will interpret and implement this part and the Indian Tribal Energy Development and Self-Determination Act (the Act) in accordance with the self-determination and energy development provisions and policies in the Act.

(b) The Secretary will liberally construe this part and the Act for the benefit of tribes to implement the Federal policy of self-determination. The Secretary will construe any ambiguities in this part or the Act in favor of the tribe to implement a TERA as authorized by this part and the Act.

#### **§ 224.30 What definitions apply to this part?**



[top](#)

*Act* means the Indian Tribal Energy Development and Self-Determination Act of 2005, as promulgated in Title V of the Energy Policy Act of 2005, Public Law 109–58, 25 U.S.C. 3501–3504.

*Application* means the application submitted for a TERA under subpart B.

*Business agreement* means:

(1) Any permit, contract, joint venture, option, or other agreement that furthers any activity related to locating, producing, transporting, or marketing energy resources on tribal land;

(2) Any amendment, supplement, or other modification to such an agreement; or

(3) Any other business agreement entered into or subject to administration under a TERA.

*Days* mean calendar days in computing any period prescribed or allowed by the Act and this part:

(1) Do not include the day of the event from which the period begins to run;

(2) Include the last day of the period, unless it is a Saturday, Sunday, or Federal holiday, in which event the period runs until the end of the next day which is not a Saturday, Sunday, or Federal holiday; and

(3) When the period prescribed or allowed is less than 11 days, exclude intermediate Saturdays, Sundays, and Federal holidays from the computation.

*Decision Deadline* means the 120-day period within which the Director will make a decision about a petition submitted by an interested party under subpart E. The Director may extend this period for up to 120 days.

*Department* means the Department of the Interior.

*Designated Tribal Official* means the official designated in a tribe's pre-application consultation request, application, or agreement to assist in scheduling consultations or to receive communications from the Secretary or the Director to the tribe regarding the status of a TERA or activities under a TERA.

*Director* means the Director of the Office of Indian Energy and Economic Development or the Secretary's designee, authorized to act on behalf of the Secretary.

*Energy Resources* means both renewable and nonrenewable energy sources, including, but not limited to, natural gas, oil, uranium, coal, nuclear, wind, solar, geothermal, biomass, and hydrologic resources.

*Imminent jeopardy to a physical trust asset* means an immediate threat of devaluation, degradation, damage, or loss of a physical trust asset, as determined by the Secretary, caused by the noncompliance of a tribe or third party with a TERA or applicable Federal laws.

*Interested party* means a person or entity who has filed a petition with the Secretary under subpart E seeking review of a tribe's compliance with a TERA and who meets the criteria in §224.101.

*Lease* means a written agreement, or modification of a written agreement, between a tribe and a tenant or lessee, whereby the tenant or lessee is granted a right to possession of tribal land or energy mineral resources for purposes of energy resource development.

*Petitioner* means a person or entity who has filed a petition under subpart E with a tribe or the Secretary seeking review of a tribe's compliance under a TERA. A petitioner is not considered to be an interested party unless the petitioner meets the criteria in §224.101.

*Physical trust asset* means a physical asset held in trust by the United States for a tribe or individual Indian or by a tribe or individual Indian subject to a restriction against alienation under the laws of the United States. "Physical trust asset" does not include:

(1) Any improvements (for example, wells or structures) to the assets held in trust or restricted status; or

(2) Monetary assets.

*Public* means one or more natural or legal persons, and their associations, organizations, or groups; or Federal, State, tribal and local government agencies; or private industry and their associations, organizations, or groups.

*Right-of-way* means an easement, right, or other authorization over tribal lands, granted or subject to administration under a TERA, for a pipeline or electric transmission or distribution line that serves a facility located on tribal land that is related to energy resource development.

*Secretary* means the Secretary of the Interior or the Secretary's designee.

*TERA* means tribal energy resource agreement.

*Tribal governing body* means a tribe's governing entity, such as tribal council or tribal business committee, as established under tribal or Federal law and recognized by the Secretary.

*Tribal land* means any land or interests in land owned by a tribe or tribes, title to which is held in trust by the United States, or is subject to a restriction against alienation under the laws of the United States. For the purposes of this part, tribal land includes land taken into trust or subject to restrictions on alienation under the laws of the United States after the effective date of the agreement.

*Tribe* means any Indian tribe, band, nation, or other organized group or community that is recognized as eligible for the special programs and services provided by the United States to Indians because of their status as Indians, except a Native Corporation as defined in the Alaska Native Claims Settlement Act, 43 U.S.C. 1602.

*Violation or breach* means any breach or other violation by another party of any provision in a lease, business agreement, or right-of-way under a TERA or any activity or occurrence under a lease business agreement or right-of-way that constitutes a violation of Federal or tribal environmental law.

#### **§ 224.40 How does the Act or a TERA affect the Secretary's trust responsibility?**



[top](#)

(a) The Act (25 U.S.C. 3504(e)(6)) preserves the Secretary's trust responsibilities relating to mineral and other trust resources and requires the Secretary to act in good faith and in the best interest of Indian tribes.

(b) Neither the Act nor this part absolves the Secretary of responsibilities to Indian tribes under the trust relationship, treaties, statutes, regulations, Executive Orders, agreements or other Federal law.

(c) The Act and this part preserve the Secretary's trust responsibility to ensure that the rights and interests of an Indian tribe are protected if:

(1) Another party to a lease, business agreement, or right-of-way executed under an approved TERA violates any term of the lease, business agreement, or right-of-way, or any applicable Federal law; or

(2) Any provision of a lease, business agreement, or right-of-way violates the TERA under which it was executed.

(d) The United States is not liable for losses to any party (including any tribe) for any negotiated term of, or any loss resulting from, the negotiated terms of a lease, business agreement, or right-of-way the tribe executes under a TERA.

#### **§ 224.41 When does the Secretary require agreement of more than one tribe to approve a TERA?**



[top](#)

When tribal land held for the benefit of more than one tribe is contemplated for inclusion in a TERA, each appropriate tribal governing body must request a pre-application consultation meeting, and submit a resolution or formal act of the tribal governing body approving the submission of any application. Each appropriate tribal governing body must also sign the TERA, if it is approved.

#### **§ 224.42 How does the Paperwork Reduction Act affect these regulations?**



[top](#)

The information collected from the public is cleared and covered by OMB Control Number 1076-0167. The sections of this rule which have information collections are §§224.53, 224.57(d), 224.61, 224.63, 224.64, 224.65, 224.68(d), 224.76, 224.83, 224.87, 224.109, 224.112, 224.120(a), 224.139(b), 224.156, and 224.173. Please note that a Federal Agency may not conduct or sponsor, and you are not required to respond to, a collection of information unless it displays a currently valid OMB control number.

#### **Subpart B—Procedures for Obtaining Tribal Energy Resource Agreements**



[top](#)

#### **§ 224.50 What is the purpose of this subpart?**



[top](#)

This subpart establishes procedures for:

- (a) Pre-application and application consultations and process;
- (b) Requirements for the content of applications;
- (c) Submittal of completed applications; and
- (d) Secretarial review and processing of applications.

#### **Pre-application Consultation and the Form of Application**



[top](#)

#### **§ 224.51 What is a pre-application consultation between a tribe and the Director?**



[top](#)

- (a) A tribe interested in entering into a TERA should request a pre-application consultation by writing to the Director, Office of Indian Energy and Economic Development. The request should include the name and contact information for the Designated Tribal Official who will coordinate scheduling with the Director.
- (b) Upon receiving a pre-application consultation request, the Director will contact the Designated Tribal Official to schedule a pre-application consultation meeting. The Director may also initiate pre-application discussions with the tribal governing body.
- (c) At the pre-application consultation meeting, the tribe and the Director may discuss any of the matters related to a future application including, but not limited to:
  - (1) The application process;
  - (2) The potential scope of the tribe's future application, including any regulatory or administrative activities that the tribe anticipates exercising;
  - (3) The required content of an application for a TERA;
  - (4) The energy resource the tribe anticipates developing;
  - (5) The tribe's capacity to manage and regulate the energy resource development the tribe identifies;
  - (6) Potential opportunities for funding capacity-building and other activities related to the energy resource the tribe anticipates developing under a TERA; and
  - (7) Any other matters applicable to this part, the Act, and the tribe.

#### **§ 224.52 What may a tribe include in a TERA?**



[top](#)

A TERA under this part:

- (a) May include development of all or part of a tribe's energy resources;

- (b) Must specify the type of energy resource included;
- (c) May include assumption by the tribe of certain activities normally carried out by the Department, except for inherently Federal functions; and
- (d) Must specify the services or resources related to the specific activity related to energy resource development that the tribe proposes to assume from the Department.

**§ 224.53 What must an application for a TERA contain?**



- (a) An application for a TERA must contain all of the following:
  - (1) A proposed TERA between the tribe and the Secretary, signed by the authorized representative of the tribe, that contains the provisions required by §224.63;
  - (2) A statement that the Secretary recognizes the tribe as an Indian tribe and that the tribe has tribal land;
  - (3) A brief description of the tribe's form of government;
  - (4) Copies of relevant portions of tribal documents (see paragraph (b) of this section);
  - (5) A map, legal description, and general description of the tribal land that the tribe intends to include in the TERA;
  - (6) A statement that meets the requirements in paragraph (c) of this section;
  - (7) A statement describing the tribe's experience in negotiating and administering energy-related leases, business agreements, and rights-of-way issued under other Federal laws that includes descriptions of significant leases, business agreements, and rights-of-way the tribe has entered into with third parties or to which it has consented;
  - (8) A description of the expertise that the tribe will use to administer the TERA and an explanation of how that expertise meets the requirements of paragraph (d) of this section;
  - (9) A statement of the scope of administrative activities that the tribe intends to conduct and an explanation of how that meets the requirements of paragraph (e) of this section;
  - (10) A statement that meets the requirements of paragraph (f) of this section describing the capability of the tribe to assume all of the activities the tribe has identified in the application;
  - (11) A copy of the resolution or formal action of the tribal governing body or bodies under §224.41 that approves submission of an application for a TERA; and
  - (12) A designation of, and contact information for, the Designated Tribal Official who will receive notifications from the Secretary or the Director regarding the status of the TERA application.
- (b) The documents required by paragraph (a)(4) of this section include documents such as a constitution, code, ordinance, or resolution, that designate the tribal governing body or tribal officials that have authority to enter into leases, business agreements, or rights-of-way on behalf of the tribe.
- (c) The statement required by paragraph (a)(6) of this section must:
  - (1) If applicable, state that the tribe retains the option of entering into energy-related leases or agreements under laws other than the Act for any tribal land that the TERA includes; and
  - (2) State one of the following:
    - (i) The tribe intends the TERA to include all tribal land, energy resources, and categories of energy-related leases, business agreements, and rights-of-way; or

(ii) The tribe intends the TERA to include only certain tribal land, energy resources, or categories of energy-related leases, business agreements, or rights-of-way in the TERA. In this case, the statement must specify and describe the tribal land, energy resources, or categories of energy-related leases, business agreements, or rights-of-way that the tribe intends to include in the TERA.

(3) State the tribe's intent to amend or modify leases, business agreements, or rights-of-way that exist when a TERA is approved if those activities are directly related to the activities authorized by the TERA. The tribe's ability to amend or modify such leases, business agreements or rights-of-way requires the agreement of the other parties to the lease, business agreement or rights-of-way, which must be stated in the TERA.

(d) The statement required by paragraph (a)(8) of this section must describe the expertise that the tribe will use in the four areas specified in paragraph (d)(1) of this section. It must also address, at a minimum, the administrative and personnel resources specified in paragraph (d)(2) of this section.

(1) The statement must describe the expertise that the tribe will use to:

(i) Negotiate or review leases, business agreements, or rights-of-way under the TERA;

(ii) Evaluate the environmental effects, including those related to cultural resources, of leases, business agreements, or rights-of-way entered into under a TERA;

(iii) Review proposals for leases, business agreements and rights-of-way under the TERA; and

(iv) Monitor the compliance of a third party with the terms and conditions of any leases, business agreements and rights-of-way covered by the TERA.

(2) The statement must describe the following:

(i) Existing energy resource development related departments or administrative divisions within the tribe;

(ii) Proposed energy resource development related departments or administrative divisions within the tribe;

(iii) Existing energy resource development related expertise possessed by the tribe, including a description of the relevant expertise of designated tribal employees, consultants and/or advisors; and

(iv) Proposed energy resource development related expertise that the tribe may acquire, including a description of the relevant expertise of designated tribal employees, consultants and/or advisors that the tribe intends to hire or retain.

(e) The statement required by paragraph (a)(9) of this section must describe the amount of administrative activities related to the permitting, approval, and monitoring of activities, as applicable, that the tribe proposes to undertake under any lease, business agreement, or right-of-way the tribe executes under an approved TERA.

(1) If the tribe proposes to regulate activities, the tribe must state its intent and describe the scope of the tribe's plan for such administration and management in sufficient detail for the Secretary to determine the tribe's capacity to administer and manage the regulatory activity(ies).

(2) The tribe's intended scope of administrative responsibilities may not include the responsibilities of the Federal Government under the Endangered Species Act or other inherently Federal functions.

(3) If the tribe intends to regulate activities, it should also describe the regulatory activities it desires to assume in the geographical area identified in §224.53(c)(2) with respect to leases, business agreements, and rights-of-way that exist when a TERA is approved.

(f) The statement required by paragraph (a)(10) of this section must:

(1) Describe the tribe's ability to negotiate and enter into leases, business agreements, and rights-of-way;

(2) Include a discussion of the estimated annual costs to the tribe to assume those activities the tribe has identified in the application and the proposed source of tribal funds to carry out those activities; and

(3) Describe the estimated annual amounts needed to conduct those activities the tribe has identified in the application and identify the Federal program that may provide those funds, if one of the sources of tribal funds includes grants or contract awards from the Department, the Department of Energy, or other Federal agencies.

(4) Include a description of any:

(i) Compacts and contracts between the tribe and the Secretary under the Indian Self-Determination and Education Assistance Act, as amended;

(ii) Environmental programs a tribe has assumed under the Clean Water Act (33 U.S.C. 1251 *et seq.* ) or the Clean Air Act (42 U.S.C.A. 7401); or

(iii) Cooperative agreements under the Federal Oil and Gas Royalty Management Act (30 U.S.C. 1701 *et seq.* ).

## Processing Applications



[top](#)

### § 224.54 How must a tribe submit an application?



[top](#)

A tribe must submit an application and all supporting documents in written and electronic form to the Director.

### § 224.55 Is information a tribe submits throughout the TERA process under this part subject to disclosure to third parties?



[top](#)

The requirements of this section implement the requirements of the Freedom of Information Act (5 U.S.C. 552) (FOIA) and 43 CFR part 2:

(a) Information a tribe submits to the Department throughout the TERA process under this part may be subject to disclosure to third parties under FOIA unless a FOIA exemption or exception applies or other provisions of law protect the information.

(b) A tribe may, but is not required to, designate information it submits as confidential commercially or financially sensitive information, as applicable, in any submissions it makes throughout the TERA process, including, but not limited to:

(1) Pre-application information;

(2) Application information

(3) A final proposed TERA;

(4) Any amendments to a TERA; and

(5) Leases, business agreements, and grants of right-of-way executed under an approved TERA.

(c) Upon receipt of a FOIA request for records that contain commercial or financial information a tribe has submitted under the TERA process, as required by 43 CFR part 2 the Department will provide the tribe, as submitter, with written notice of the FOIA request if:

(1) The tribe has designated the information as confidential commercial or financial information; or

(2) The Department has reason to believe that the information requested may be protected under FOIA Exemption 4 (trade secrets and commercial or financial information which is obtained from a person and is privileged or confidential).

(d) The notice to the tribe will:

(1) Include a copy of the FOIA request;

(2) Describe the information requested or include copies of the pertinent records;

(3) Advise the tribe of procedures for objecting to the release of the requested information and specify the time limit for the tribe's response;

(4) Give the tribe no less than ten (10) working days from the Department's notice to object to the release and explain the basis for objection, if any;

(5) Advise the tribe that:

(i) Information contained in the tribe's objections may be subject to disclosure under FOIA if the Department receives a FOIA request for it; and

(ii) If the tribe's objections contain commercial or financial information and a requestor asks for the objections under FOIA, the same notification procedures as above will apply;

(6) Advise the tribe that it is the Department, rather than the tribe, that is responsible for deciding whether the information will be released or withheld;

(7) If the tribe designated the information as commercial or financial information 10 or more years before the FOIA request, the Department will request the tribe's views on whether the tribe still considers the information to be confidential;

(e) If the tribe has any objection to disclosure of the information, the tribe must submit a detailed written statement to the Department including the following:

(1) The justification for withholding any portion of the information under any exemption of FOIA, and if the applicable exemption is Exemption 4, the tribe must submit a specific and detailed discussion of:

(i) Whether the Federal government required the information to be submitted, and, if so, how substantial competitive harm or other business harm would likely result from release of the information; or

(ii) Whether the tribe provided the information voluntarily and, if so, how the information fits into a category of information that the tribe customarily does not release to the public;

(2) A certification that the information is confidential, has not been disclosed to the public by the tribe, and is essentially non-public because it is not routinely available to the public from other sources;

(3) If not already provided, a tribal contact telephone and fax number so that the Department can communicate with the tribe about the FOIA request;

(f) The Department will review and consider all objections to release that are received within the time limits specified in the notice to the tribe, and if the tribe does not respond within the time limits specified in the notice, the Department will presume that the tribe has no objection to release of the information;

(g) If the Department decides to release the information over the objection of the tribe, it will notify the tribe in writing by certified mail, return receipt requested, and will include copies of the records the Department intends to release and the reasons for deciding to release them. The notice will also inform the tribe that it intends to release the records within 10 working days after the tribe's receipt of the notice.

#### **§ 224.56 What is the effect of the Director's receipt of a tribe's complete application?**



[top](#)

The Director's receipt of a tribe's complete application begins a 270-day statutorily mandated period during which the Secretary must approve or disapprove a proposed TERA. With the consent of the tribe, the Secretary may extend the 270-day period for making a decision.

#### **§ 224.57 What must the Director do upon receipt of an application?**



[top](#)

(a) Upon receiving an application for a TERA, the Director must:

(1) Promptly notify the Designated Tribal Official in writing that the Director has received the application and the date it was received;

(2) Within 30 days from the date of receiving the application, determine whether the application is complete; and

(3) Take the following actions:

If the Director determines that . . .	Then the Director must . . .
(i) The application is complete	(A) Issue a written notice and a request for an application consultation meeting to the Designated Tribal Official; and (B) If appropriate, notify other Departmental bureaus and offices of receiving the application and provide copies.
(ii) The application is not complete	(A) Issue a written notice to the Designated Tribal Official that the application is not complete; (B) Specify the additional information the tribe is required to submit to make the application complete; and (C) Start the 270-day review period only when the Director receives a complete application.

(b) Unless the Director notifies the Designated Tribal Official during the 30-day review period that the application is not complete, the application is presumed to be complete and the 270-day review period under 25 U.S.C. 3504(e)(2)(A) of the Act will begin as of the date that the application was received.

#### Application Consultation Meeting



[top](#)

#### § 224.58 What is an application consultation meeting?



[top](#)

An application consultation meeting is a meeting held at the tribe's headquarters between the Director and the tribal governing body and any other representatives that the tribe may designate to discuss the TERA application. The Secretary will designate representatives of appropriate Departmental offices or bureaus to attend the application consultation meeting, as necessary. The tribe may record the meeting. The meeting will:

(a) Be held at the earliest practicable time after the Director receives a tribe's complete application;

(b) Include a thorough discussion of the tribe's application;

(c) Identify the specific services consistent with the Secretary's ongoing trust responsibility and available resources that the Department would provide to the tribe upon the approval of a TERA;

(d) Include a discussion of the relationship of the tribe to other Federal agencies with responsibilities for implementing or ensuring compliance with the terms and conditions of leases, business agreements, or rights-of-way and applicable Federal laws;

(e) Include a discussion of the relationship of the tribe to its members, to State and local governments,

and to non-Indians who may be affected by approval of a TERA or by leases, business agreements, or rights-of-way that the tribe may enter into or grant under an approved TERA;

(f) Include a discussion of the tribal administrative, financial, technical, and managerial capacities needed to carry out the tribe's obligations under a TERA; and

(g) Include a discussion of the form of the TERA and the timing and relative responsibilities of the parties for its preparation.

#### **§ 224.59 How will the Director use the results of the application consultation meeting?**



The Director will use the information gathered during the application consultation meeting in conjunction with information provided through §§224.53 and 224.63 to determine the energy resource development capacity of the tribe as detailed in §224.72.

#### **§ 224.60 What will the Director provide to the tribe after the application consultation meeting?**



Within 30 days following the meeting with the tribe, the Director will provide to the Designated Tribal Official a written report on the application consultation meeting. The report must include the Director's recommendations, if any, for revising the proposed TERA that was submitted as part of the tribe's application.

#### **§ 224.61 What will the tribe provide to the Director after receipt of the Director's report on the application consultation meeting?**



If the tribe wishes to proceed with the application, the tribe must submit a final proposed TERA to the Director within 45 days following the date of the Tribe's receipt of the Director's report on the application consultation meeting.

#### **§ 224.62 May a final proposed TERA differ from the original proposed TERA?**



The final proposed TERA may or may not contain provisions that differ from the original proposed TERA submitted with the application.

(a) If a final proposed TERA does not differ significantly or materially from the original TERA contained in the complete application, the 270-day review period will begin to run on the date the original complete application was received (under §224.57(c)) or on the date established by operation of §224.57(d)).

(b) If a final proposed TERA differs significantly or materially from the original TERA contained in the complete application, the Secretary, with the tribe's consent, may extend the 270-day period for a reasonable time. The Secretary will notify the tribe in writing if an extension of time is necessary.

### **TERA Requirements**



#### **§ 224.63 What provisions must a TERA contain?**



A TERA must contain all the elements required by this section.

(a) A provision for the Secretary's periodic review and evaluation of the tribe's performance under a TERA.

(b) A provision that recognizes the authority of the Secretary, upon a finding of imminent jeopardy to a physical trust asset, to take actions the Secretary determines to be necessary to protect the asset, including reassumption under subparts F and G of this part.

(c) A provision under which the tribe establishes and ensures compliance with an environmental review process for leases, business agreements, and rights-of-way which, at a minimum:

(1) Identifies and evaluates all significant environmental effects (as compared to a no-action alternative), including effects on cultural resources, arising from a lease, business agreement, or right-of-way;

(2) Identifies proposed mitigation measures, if any, and incorporates appropriate mitigation measures into the lease, business agreement, or right-of-way;

(3) Informs the public and provides opportunity for public comment on the environmental impacts of the approval of the lease, business agreement or right-of-way;

(4) Provides for tribal responses to relevant and substantive public comments before tribal approval of the lease, business agreement or right-of-way;

(5) Provides for sufficient tribal administrative support and technical capability to carry out the environmental review process; and

(6) Develops adequate tribal oversight of energy resource development activities under any lease, business agreement or right-of-way under a TERA that any other party conducts to determine whether the activities comply with the TERA and applicable Federal and tribal environmental laws.

(d) Provisions that require, with respect to any lease, business agreement, or right-of-way approved under a TERA, all of the following:

(1) Mechanisms for obtaining corporate, technical, and financial qualifications of a third party that has applied to enter into a lease, business agreement, or right-of-way;

(2) Express limitations on duration that meet the restrictions of the Act and this Part under §224.86;

(3) Mechanisms for amendment, transfer, and renewal;

(4) Mechanisms for obtaining, reporting and evaluating the economic return to the tribe;

(5) Mechanisms for securing technical information about activities and ensuring that technical activities are performed in compliance with terms and conditions;

(6) Assurances of the tribe's compliance with all applicable environmental laws;

(7) Requirements that the lessee, operator, or right-of-way grantee will comply with all applicable environmental laws;

(8) Identification of tribal representatives with the authority to approve a lease, business agreement, or right-of-way and the related energy development activities that would occur under a lease, business agreement, or right-of-way;

(9) Public notification that a lease, business agreement, or right-of-way has received final tribal approval;

(10) A process for consultation with affected States regarding off-reservation impacts, if any, identified under paragraph (c) of this section;

(11) A description of remedies for breach;

(12) A statement that any provision that violates an express term or requirement of the TERA is null and void;

(13) A statement that if the Secretary determines that any provision that violates an express term or

requirement of the TERA is material, the Secretary may suspend or rescind the lease, business agreement, or right-of-way, or take any action the Secretary determines to be in the best interest of the tribe, including, with the consent of the parties, revising the nonconforming provisions so that they conform to the intent of the applicable portion of the TERA; and

(14) A statement that the lease, business agreement, or right-of-way subject to a TERA, unless otherwise provided, goes into effect when the tribe delivers executed copies of the lease, business agreement, or right-of-way to the Director by first class mail return receipt requested or express delivery. The parties to a lease, business agreement, or right-of-way may agree in writing that any provision of their contract may have retroactive application.

(e) Citations to any applicable tribal laws, regulations, or procedures that:

(1) Provide opportunity for the public to comment on and to participate in public hearings, if any, under paragraph (c)(2) of this section; and

(2) Provide remedies that petitioning parties must exhaust before filing a petition with the Secretary under subpart E of this part.

(f) Provisions that require a tribe to provide the Secretary with citations to any tribal laws, regulations, or procedures the tribe adopts after the effective date of a TERA that establish, amend, or supplement tribal remedies that petitioning parties must exhaust before filing a petition with the Secretary under subpart E of this part.

(g) Provisions that designate a person or entity, together with contact information, authorized by the tribe to maintain and disseminate to requesting members of the public current copies of tribal laws, regulations, or procedures that establish or describe tribal remedies that petitioning parties must exhaust before instituting appeals under subpart E of this part.

(h) Identification of financial assistance, if any, that the Secretary has agreed to provide to the tribe to assist in implementation of the TERA, including the tribe's environmental review of individual energy development activities.

(i) Provisions that require a tribe to notify the Secretary and the Director in writing, as soon as practicable after the tribe receives notice, of a violation or breach as defined in this Part.

(j) Provisions that require the tribe and the tribe's financial experts to adhere to Government auditing standards and to applicable continuing professional education requirements.

(k) Provisions that require the tribe to submit to the Director information and documentation of payments made directly to the tribe, if any. These provisions enable the Secretary to discharge the trust responsibility of the United States to enforce the terms of, and protect the rights of the tribe under, a lease, business agreement, or right-of-way. Required documentation must include documents evidencing proof of payment such as cancelled checks; cash receipt vouchers; copies of money orders or cashiers checks; or verification of electronic payments.

(l) Provisions that ensure the creation, maintenance and preservation of records related to leases, business agreements, or rights-of-way and performance of activities a tribe assumed under a TERA sufficient to facilitate the Secretary's periodic review of the TERA. The Secretary will use these records as part of the periodic review and evaluation process under §224.132. Approved Departmental records retention procedures under the Federal Records Act (44 U.S.C. Chapters 29, 31, and 33) provide a framework the tribe may use to ensure that its records under a TERA adequately document essential transactions, furnish information necessary to protect its legal and financial rights, and enable the Secretary to discharge the trust responsibility if:

(1) Any other party violates the terms of any lease, business agreement, or right-of-way; or

(2) Any provision of a lease, business agreement or right-of-way violates the TERA.

#### **§ 224.64 How may a tribe assume management of development of different types of energy resources?**



[top](#)

In order for a tribe to assume authority for approving leases, business agreements, and rights-of-way for development of another energy resource that is not included in the TERA, a tribe must apply for a new

TERA covering the authority for the development of another energy resource it wishes to assume. The Secretary's consideration of a new TERA will include a determination of the tribe's capacity to develop that type of energy resource and will trigger the public notice and opportunity for comment consistent with §224.67.

#### **§ 224.65 How may a tribe assume additional activities under a TERA?**



A tribe may assume additional activities related to the development of the same type of energy resource included in a TERA by negotiating with the Secretary an amendment to the existing TERA to include the additional activities. The Secretary will determine in each case whether the tribe has sufficient capacity to carry out additional activities the tribe may wish to assume under an approved TERA.

#### **§ 224.66 How may a tribe reduce the scope of the TERA?**



A tribe may reduce the scope of the TERA by negotiating with the Secretary an amendment to the existing TERA to eliminate an activity assumed under the TERA or a type of energy resource development managed under the TERA. Any such reduction in scope must include the return of all relevant Departmental resources transferred under the TERA and any relevant records and documents.

#### **Public Notification and Comment**



#### **§ 224.67 What must the Secretary do upon the Director's receipt of a final proposed TERA?**



(a) Within 10 days of the Director's receipt of a final proposed TERA, the Secretary must submit a notice for publication in the Federal Register advising the public:

- (1) That the Secretary is considering a final proposed TERA for approval or disapproval; and
- (2) Of any National Environmental Policy Act (NEPA) review the Secretary is conducting.

(b) The Federal Register notice will:

- (1) Contain information advising the public how to request and receive copies of or participate in any NEPA reviews, as prescribed in subpart C of this part, related to approval of the final proposed TERA; and
- (2) Contain information advising the public how to comment on a final proposed TERA.

#### **§ 224.68 How will the Secretary use public comments?**



(a) The Secretary will review and consider public comments in deciding to approve or disapprove the final proposed TERA; and

(b) The Secretary will provide copies of the comments to the Designated Tribal Official;

(c) Upon mutual agreement between the tribe and the Secretary, the tribe may make changes in the final proposed TERA based on the comments received; and

(d) If the tribe revises the final proposed TERA based on public comments, the tribal governing body

must approve the changes, the authorized representative of the tribe must sign the final proposed TERA as revised, and the tribe must send the revised final proposed TERA to the Director. The Secretary and the tribe will consult on whether an extension of the review period is necessary under §224.62(b).

### **Subpart C—Approval of Tribal Energy Resource Agreements**



[top](#)

#### **§ 224.70 Will the Secretary review a proposed TERA under the National Environmental Policy Act?**



[top](#)

Yes, the Secretary will conduct a review under the National Environmental Policy Act (NEPA) of the potential impacts on the quality of the human environment that might arise from approving a final proposed TERA. The scope of the Secretary's evaluation will be limited to the scope of the TERA. The public comment period, when required, under the NEPA review will occur concurrently with the public comment period for a TERA under §224.67.

#### **§ 224.71 What standards will the Secretary use to decide to approve a final proposed TERA?**



[top](#)

The Secretary will consider the best interests of the tribe and the Federal policy of promoting tribal self-determination in deciding whether to approve a final proposed TERA. The Secretary must approve a final proposed TERA if it contains the provisions required by the Act and this part and the Secretary determines that the tribe has demonstrated sufficient capacity to manage the development of energy resources it proposes to develop.

#### **§ 224.72 How will the Secretary determine whether a tribe has demonstrated sufficient capacity?**



[top](#)

The Secretary will determine whether a tribe has demonstrated sufficient capacity under §224.71 based on the information obtained through the application process. The Secretary will consider:

- (a) The specific energy resource development the tribe proposes to regulate;
- (b) The scope of the administrative or regulatory activities the tribe seeks to assume;
- (c) Materials and information submitted with the application for a TERA, the result of meetings between the tribe and a representative of the Department and the Director's written report;
- (d) The history of the tribe's role in energy resource development, including negotiating and approval or disapproval of pre-existing energy-related leases, business agreements, and rights-of-way;
- (e) The administrative expertise of the tribe available to regulate energy resource development within the scope of the final proposed TERA or the tribe's plans for establishing that expertise;
- (f) The financial capacity of the tribe to maintain or procure the technical expertise needed to evaluate proposals and to monitor anticipated activities in a prudent manner;
- (g) The tribe's past performance administering contracts and grants associated with self-determination programs, cooperative agreements with Federal and State agencies, and environmental programs administered by the Environmental Protection Agency;
- (h) The tribe's past performance monitoring activities undertaken by third parties under approved leases, business agreements, or rights-of-way; and

(i) Any other factors the Secretary finds to be relevant in light of the scope of the proposed TERA.

**§ 224.73 How will the scope of energy resource development affect the Secretary's determination of the tribe's capacity?**



The Secretary's review under §224.72 of the tribe's capacity to manage and regulate energy resource development under the TERA will include a determination as to each type of energy resource development subject to the TERA for which the tribe seeks to regulate, and each type of regulatory activity the tribe proposes to assume. The Secretary's review of a TERA must be limited to activities specified by its provisions.

**§ 224.74 When must the Secretary approve or disapprove a final proposed TERA?**



The Secretary must approve or disapprove a final proposed TERA or a revised final proposed TERA within 270 days of the Director's receipt of a complete application for a TERA. With the consent of the tribe, or as provided in §224.62(b), the Secretary may extend the period for a decision.

**§ 224.75 What must the Secretary do upon approval or disapproval of a final proposed TERA?**



Within 10 days of the Secretary's approval or disapproval of a final proposed TERA, the Secretary must notify the tribal governing body in writing and take the following actions:

If the Secretary's decision is ...	Then the Secretary will ...
(a) To approve the final proposed TERA	(1) Sign the TERA making it effective on the date of signature, and return the signed TERA to the tribal governing body; and (2) Maintain a copy of the TERA and any subsequent amendments or supplements to the TERA.
(b) To disapprove the final proposed TERA	Send the tribe a notice of disapproval that must include: (1) The basis of the disapproval; (2) The changes or other actions required to address the Secretary's basis for disapproval; and (3) A statement that the decision is a final agency action and is subject to judicial review.

**§ 224.76 Upon notification of disapproval, may a tribe re-submit a revised final proposed TERA?**



Yes, within 45 days of receiving the notice of disapproval, or a later date as the Secretary and the tribe agree to in writing, the tribe may re-submit a revised final proposed TERA, approved by the tribal governing body and signed by the tribe's authorized representative, to the Director that addresses the Secretary's concerns. Unless the Secretary and the tribe otherwise agree, the Secretary must approve or disapprove the revised final proposed TERA within 60 days of the Director's receipt of the revised final proposed TERA. Within 10 days of the Secretary's approval or disapproval of a revised final proposed TERA, the Secretary must notify the tribal governing body in writing and take the following actions:

If the Secretary's decision is . . .	Then the Secretary will . . .
(a) To approve the revised final proposed TERA	(1) Sign the TERA making it effective on the date of signature, and return the signed TERA to the tribal governing body; and (2) Maintain a copy of the TERA and any subsequent amendments or supplements to the TERA.
(b) To disapprove the revised final proposed TERA	Send the tribe a notice of disapproval that must include: (1) The reasons for the disapproval; and (2) A statement that the decision is a final agency action and is subject to judicial review.

**§ 224.77 Who may appeal the Secretary's decision on a final proposed TERA or a revised final proposed TERA?**



[top](#)

Only a tribe applying for a TERA may appeal the Secretary's decision to disapprove a final proposed TERA or a revised final proposed TERA in accordance with the appeal procedures contained in subpart I of this part. No other person or entity may appeal the Secretary's decision. The Secretary's decision to approve a final proposed TERA or a revised final proposed TERA is a final agency action.

**Subpart D—Implementation of Tribal Energy Resource Agreements**



[top](#)

**Applicable Authorities and Responsibilities**



[top](#)

**§ 224.80 Under what authority will a tribe perform activities for energy resource development?**



[top](#)

A tribe will perform activities for energy resource development activities undertaken under a TERA under the authorities provided in the approved TERA. Notwithstanding anything in this part or an approved TERA to the contrary, a tribe will retain all sovereign and other powers it otherwise possesses.

**§ 224.81 What laws are applicable to activities?**



[top](#)

Federal and tribal laws apply to activities under a TERA, unless otherwise specified in the TERA.

**§ 224.82 What activities will the Department continue to perform after approval of a TERA?**



[top](#)

After approval of a TERA, the Department will provide a tribe:

(a) All activities that the Department performs unless the tribe has assumed such activities under the

TERA;

(b) Access to title status information and support services needed by a tribe in the course of evaluating proposals for leases, business agreements, or rights-of-way;

(c) Coordination between the tribe and the Department for ongoing maintenance of accurate real property records;

(d) Access to technical support services within the Department to assist the tribe in evaluating the physical, economic, financial, cultural, social, environmental, and legal consequences of approving proposals for leases, business agreements, or rights-of-way under a TERA; and

(e) Assistance to ensure that third-party violations or breaches of the terms of leases, business agreements, or rights-of-way or applicable provisions of Federal law by third parties are handled appropriately.

#### **Leases, Business Agreements, and Rights-of-Way Under a TERA**



[top](#)

#### **§ 224.83 What must a tribe do after executing a lease or business agreement, or granting a right-of-way?**



[top](#)

Following the execution of a lease, business agreement, or grant of right-of-way under a TERA, a tribe must:

(a) Inform the public of approval of the lease, business agreement, or right-of-way under the authority granted in the TERA; and

(b) Send a copy of the executed lease, business agreement, or right-of-way, or amendments, to the Director within one business day of execution. The copy must be sent by certified mail return receipt requested or by overnight delivery.

#### **§ 224.84 When may a tribe grant a right-of-way?**



[top](#)

A tribe may grant a right-of-way under a TERA if the grant of right-of-way is over tribal land for a pipeline or an electric transmission or distribution line if the pipeline or electric transmission or distribution line serves:

(a) An electric generation, transmission, or distribution facility located on tribal land; or

(b) A facility located on tribal land that processes or refines energy resources developed on tribal land.

#### **§ 224.85 When may a tribe enter into a lease or business agreement?**



[top](#)

A tribe may enter into a lease or business agreement for the purpose of energy resource development for:

(a) Exploration for, extraction of, or other development of the tribe's energy mineral resources on tribal land including, but not limited to, marketing or distribution;

(b) Construction or operation of an electric generation, transmission, or distribution facility located on tribal land; or

(c) A facility to process or refine energy resources developed on tribal land.

**§ 224.86 Are there limits on the duration of leases, business agreements, and rights-of-way?**



[top](#)

(a) The duration of leases, business agreements, and rights-of-way entered into under a TERA are limited as follows:

- (1) For leases and business agreements, except as provided in paragraph (b) of this section, 30 years;
- (2) For leases for production of oil resources and gas resources, or both, 10 years and as long after as oil or gas production continues in paying quantities; and
- (3) For rights-of-way, 30 years.

(b) A lease or business agreement a tribe enters into, or a right-of-way a tribe grants may be renewed at the discretion of the tribe as long as the TERA remains in effect and the approved activities have not been rescinded by the tribe or suspended or reassumed by the Department.

**Violation or Breach**



[top](#)

**§ 224.87 What are the obligations of a tribe if it discovers a violation or breach?**



[top](#)

As soon as practicable after discovering or receiving notice of a violation or breach of a lease, business agreement, or right-of-way of a Federal or tribal environmental law resulting from an activity undertaken by a third party under a lease, business agreement, or right-of-way, the tribe must provide written notice to the Director describing:

- (a) The nature of the violation or breach in reasonable detail;
- (b) The corrective action taken or planned by the tribe; and
- (c) The proposed period for the corrective action to be completed.

**§ 224.88 What must the Director do after receiving notice of a violation or breach from the tribe?**



[top](#)

After receiving notice of a violation or breach from the tribe, the Director will:

- (a) Review the notice and conduct an investigation under §224.135(b) including, as necessary:
  - (1) An on-site inspection; and
  - (2) A review of relevant records, including transactions and reports.
- (b) If the Director determines, after the investigation, that a violation or breach is not causing or will not cause imminent jeopardy to a physical trust asset, the Director will review, for concurrence or disapproval, the corrective action to be taken or imposed by the tribe and the proposed period for completion of the corrective action;
- (c) If the Director determines, after the investigation, that a violation or breach is causing or will cause imminent jeopardy to a physical trust asset, the Director will proceed under the imminent jeopardy provisions of subpart F of this part.

**§ 224.89 What procedures will the Secretary use to enforce leases, business agreements, or rights-of-way?**



[top](#)

(a) The Secretary and a tribe will consult with each other regarding enforcement of and Secretarial assistance needed to enforce leases, business agreements, or rights-of-way entered into under a TERA. When appropriate, the Secretary will:

(1) Use the notification and enforcement procedures established in 25 CFR parts 162, 211 and 225 to ensure compliance with leases and business agreements; and

(2) Use the notification and enforcement procedures of 25 CFR part 169 to ensure compliance with rights-of-way.

(b) All enforcement remedies established in 25 CFR parts 162, 211, 225, and 169 are available to the Secretary.

**Subpart E—Interested Party Petitions**



[top](#)

**§ 224.100 May a person or entity ask the Secretary to review a tribe's compliance with a TERA?**



[top](#)

In accordance with this subpart, a person or entity that may be an interested party may submit to the Secretary a petition to review a tribe's compliance with a TERA. However, before filing a petition with the Secretary, a person or entity that may be an interested party must first exhaust tribal remedies, if a tribe has provided for such remedies. If a tribe has not provided for tribal remedies, a person or entity that may be an interested party may file a petition directly with the Secretary.

**§ 224.101 Who is an interested party?**



[top](#)

For the purposes of this part, an interested party is a person or entity that has demonstrated that an interest of the person or entity has sustained, or will sustain, an adverse environmental impact as a result of a tribe's failure to comply with a TERA.

**§ 224.102 Must a tribe establish a comment or hearing process for addressing environmental concerns?**



[top](#)

Yes. The Act (25 U.S.C. 3504(e)(2)(C)(iii)(I), (II) and 25 U.S.C. 3504(e)(2)(B)(iii)(X)) and subpart B of this part require a tribe to establish an environmental review process under a TERA that:

(a) Ensures that the public is notified about and has an opportunity to comment on the environmental impacts of proposed tribal action to be taken under a TERA;

(b) Requires that the tribe respond to relevant and substantive comments about the environmental impacts of a proposed tribal action before the tribe approves a lease, business agreement, or right-of-way; and

(c) Provides for a process for consultation with any affected States regarding off-reservation environmental impacts, if any, resulting from approval of a lease, business agreement, or right-of-way.

**§ 224.103 Must a tribe establish other public participation processes?**



[top](#)

No. Except for the environmental review process required by the Act and §224.63(b)(1), a tribe is not required to establish a process for public participation concerning non-environmental issues in a TERA or leases, business agreements or rights-of-way undertaken under a TERA. However, a tribe may elect to establish procedures that permit the public to participate in public hearings or that expand the scope of matters about which the public may comment.

**§ 224.104 Must a tribe enact tribal laws, regulations, or procedures permitting a person or entity to allege that a tribe is not complying with a TERA?**



[top](#)

No. A tribe is not required, but may elect, to enact tribal laws, regulations, or procedures permitting a person or entity that may be an interested party to allege that a tribe is not complying with its TERA.

**§ 224.105 How may a person or entity obtain copies of tribal laws, regulations, or procedures that would permit an allegation of noncompliance with a TERA?**



[top](#)

(a) A person or entity that may be an interested party may obtain copies of tribal laws, regulations, or procedures that establish tribal remedies that permit a person or entity to allege that the tribe is not complying with its TERA by making a request to the tribe in accordance with the TERA and §224.63(g).

(b) Upon obtaining copies of tribal laws, regulations, or procedures under subsection (a), a person or entity that may be an interested party may file a petition with the tribe under those tribal laws, regulations, or procedures.

(c) If the person or entity that may be an interested party files a petition alleging noncompliance with a TERA, the person or entity becomes a petitioner, and the tribe must respond according to §224.106.

**§ 224.106 If a tribe has enacted tribal laws, regulations, or procedures for challenging tribal action, how must the tribe respond to a petition?**



[top](#)

If a tribe has enacted tribal laws, regulations, or procedures under which a petitioner may file a petition alleging noncompliance with a TERA, the tribe must:

(a) Within a reasonable time issue a final written decision under the tribal laws, regulations, or procedures that addresses the claim. The decision may include a determination of whether the petitioner is an interested party;

(b) Provide a copy of its final written decision to the petitioner; and

(c) If the tribe fails, within a reasonable period, to issue a written decision to a petition that a petitioner brings under applicable tribal laws, regulations, or procedures the petitioner may file a petition with the Secretary.

**§ 224.107 What must a petitioner do before filing a petition with the Secretary?**



[top](#)

Before a petitioner may file a petition with the Secretary under this subpart, the petitioner must have exhausted tribal remedies by participating in any tribal process under §224.106, including any tribal appeal process.

**§ 224.108 May tribes offer a resolution of a petitioner's claim?**



[top](#)

Yes. In responding to a petition filed under tribal laws, regulations or procedures, a tribe may, with the petitioner's written consent, resolve the petitioner's claims.

#### **§ 224.109 What must a petitioner claim or request in a petition filed with the Secretary?**



[top](#)

In a petition filed with the Secretary, a petitioner must:

- (a) Claim that the tribe, through its action or inaction has failed to comply with terms or provisions of a TERA, and, as a result, the petitioner's interest has sustained or will sustain an adverse environmental impact.
- (b) Request that the Secretary review the claims raised in the petition; and
- (c) Request that the Secretary take whatever action is necessary to bring a tribe into compliance with the TERA.

#### **§ 224.110 What must a petition to the Secretary contain?**



[top](#)

A petition must contain:

- (a) The petitioner's name and contact information;
- (b) Specific facts demonstrating that the interested party under §224.101, including identification of the affected interest;
- (c) Specific facts demonstrating that the petitioner exhausted tribal remedies, if tribal laws, regulations, or procedures permitted the petitioner to allege tribal noncompliance with a TERA;
- (d) A description of facts supporting the petitioner's allegation of the tribe's noncompliance with a TERA;
- (e) A description of the adverse environmental impact that the petitioner's interest has sustained or will sustain because of the tribe's alleged noncompliance with the TERA;
- (f) A copy of any written decision the tribe issued responding to the petitioner's claims;
- (g) If applicable, a statement that the tribe has issued no written decision within a reasonable time related to a claim a petitioner has filed with the tribe under applicable tribal laws, regulations, or procedures;
- (h) If applicable, a statement and supporting documentation that the tribe did not respond to the petitioner's request under §224.105(a) for copies of any tribal laws, regulations, or procedures allowing the petitioner to allege that the tribe is not complying with a TERA; and
- (i) Any other information relevant to the petition.

#### **§ 224.111 When may a petitioner file a petition with the Secretary?**



[top](#)

(a) A petitioner may file a petition with the Secretary:

- (1) By delivering the petition to the Director within 30 days of receiving the tribe's final written decision addressing the allegation of noncompliance under applicable tribal laws, regulations, or procedures;

(2) Within a reasonable period following the tribe's constructive denial of the petition under §224.106(c), and the Secretary will determine if the petition is timely in light of the applicable facts and circumstances; or

(3) The tribe did not respond to the petitioner's request for copies of any tribal laws, regulations, or procedures under §224.105(a).

(b) A petitioner may file a petition directly with the Secretary if the tribe has no tribal laws, regulations or procedures that provide the petitioner an opportunity to allege tribal noncompliance with a TERA.

#### **§ 224.112 What must the Director do upon receipt of a petition?**



[top](#)

Within 20 days after receiving a petition, the Director must:

(a) Notify the tribe in writing that the Director has received a petition;

(b) Provide a copy of the complete petition to the tribe;

(c) Initiate a petition consultation with the tribe that will address the petitioner's allegation of a tribe's noncompliance with a TERA and alternatives to resolve any noncompliance; and

(d) Notify the tribe in writing by certified mail, return receipt requested, when the petition consultation is complete.

#### **§ 224.113 What must the tribe do after it completes petition consultation with the Director?**



[top](#)

(a) Within 45 days of receiving the Director's notice that the petition consultation is complete, the tribe must respond to any claim made in the petition by submitting a written response to the Director; and

(b) Within a reasonable time after 45 days following the completion of the petition consultation process, the tribe must cure or otherwise resolve each claim of noncompliance made in the petition.

#### **§ 224.114 How may the tribe address a petition in its written response?**



[top](#)

In addition to responding to the petitioner's claims, the tribe may also:

(a) Include its interpretation of relevant provisions of the TERA and other legal requirements;

(b) Discuss whether the petitioner is an interested party;

(c) State whether the petitioner has exhausted tribal remedies, and if so, how; and

(d) Propose to cure or otherwise resolve the claims within the time frame in §224.113(b).

#### **§ 224.115 When in the petition process must the Director investigate a tribe's compliance with a TERA?**



[top](#)

The Director must investigate the petitioner's claims of the tribe's noncompliance with a TERA only after making a threshold determination that:

(a) The tribe has denied or failed to respond to each claim made in the petition within the period under

§224.113(a); or

(b) The tribe has failed, refused, or was unable to cure or otherwise resolve each claim made in the petition within a reasonable period, as determined by the Director, after the expiration of the period in §224.113(b).

**§ 224.116 What is the time period in which the Director must investigate a tribe's compliance with a TERA?**



[top](#)

(a) If the Director determines under §224.115 that one of the threshold determinations in §224.114 has been met, then within 120 days of the Director's receipt of a petition, the Director must determine whether or not a tribe is in compliance with the TERA;

(b) The Director may extend the time for determining a tribe's compliance with a TERA up to 120 days in any case in which the Director determines that additional time is necessary to evaluate the claims in the petition and the tribe's written response, if any. If the Director decides to extend the time, the Director must notify the petitioner and the tribe in writing of the extension.

**§ 224.117 Must the Director make a determination of the tribe's compliance with a TERA?**



[top](#)

(a) Yes. Upon a finding that one of the threshold determinations in §224.115 has been met, the Director must make a determination of the tribe's compliance with a TERA within the time period in §224.116.

(b) If the Director determines that the tribe is in compliance with the TERA, the Director will notify the tribe and the petitioner in writing;

(c) If the Director determines that the tribe is not in compliance with the TERA, the Director will notify the tribe and the petitioner in writing and, in addition, must provide the tribe:

(1) A written determination that describes the manner in which the TERA has been violated together with a written notice of the violations;

(2) Notice of a reasonable opportunity to comply with the TERA; and

(3) Notice of the tribe's opportunity for a hearing.

**§ 224.118 How must the tribe respond to the Director's notice of the opportunity for a hearing?**



[top](#)

The tribe must respond in writing to the Director's notice of the opportunity for a hearing within 20 days of receipt of the notice by requesting a hearing or declining to request a hearing. If the tribe does not respond within the time period, the Director will proceed with making a decision without further input from the tribe.

**§ 224.119 What must the Director do when making a decision on a petition?**



[top](#)

(a) The Director must issue a written decision to the tribe and the petitioner stating the basis for the decision about the tribe's compliance or noncompliance with the TERA within 30 days following:

(1) A hearing, if the tribe requested a hearing;

(2) The tribe's declining the opportunity for a hearing; or

(3) The tribe's failure to respond to the opportunity for a hearing within 20 days of the Director's written notice of the opportunity for a hearing.

(b) If the Director decides that the tribe is not in compliance with the TERA, the Director must:

(1) Include findings of fact and conclusions of law with the written decision to the tribe; and

(2) Take action to ensure compliance with the TERA.

**§ 224.120 What action may the Director take to ensure compliance with a TERA?**



If the Director decides that a tribe is not in compliance with a TERA, the Director may take action to ensure compliance with the TERA including:

(a) Temporarily suspending any activity under a lease, business agreement, or right-of-way until the tribe complies with the TERA; or

(b) Rescinding approval of part of the TERA, or

(c) Rescinding all of the TERA and recommending that the Secretary reassume activities under subpart G of this part.

**§ 224.121 How may a tribe or a petitioner appeal the Director's decision about the tribe's compliance with the TERA?**



A tribe or a petitioner, or both, may appeal the Director's decision on the petition under §224.119 to the Principal Deputy Assistant Secretary—Indian Affairs under subpart I of this part.

**Subpart F—Periodic Reviews**



**§ 224.130 What is the purpose of this subpart?**



This subpart describes how the Secretary and a tribe will develop and perform the periodic review and evaluation required by the Act and by a TERA.

**§ 224.131 What is a periodic review and evaluation?**



A periodic review and evaluation is an examination the Director performs to monitor a tribe's performance of activities associated with the development of energy resources and to review compliance with a TERA. During the TERA consultation, a tribe and the Director will develop a periodic review and evaluation process that addresses the tribe's specific circumstances and the terms and conditions of the tribe's TERA. The tribe will include the agreed-upon periodic review and evaluation process in its final proposed TERA.

**§ 224.132 How does the Director conduct a periodic review and evaluation?**



(a) The Director will conduct a periodic review and evaluation under the TERA, in consultation with the

tribe, and in cooperation with other Departmental bureaus and offices whose activities the tribe assumed or that perform activities for the tribe.

(b) The Director will communicate with the Designated Tribal Official throughout the process established by this section.

(c) During the periodic review and evaluation, the Director will:

(1) Review relevant records and documents, including transactions and reports the tribe prepares under the TERA;

(2) Conduct on-site inspections as appropriate; and

(3) Review compliance with statutes and regulations applicable to activities undertaken under the TERA.

(d) Review the effect on physical trust assets resulting from activities undertaken under a TERA.

(e) Upon written request, the tribe should provide the Director with records and documents relevant to the provisions of the TERA. In addition, the tribe should identify any information in these submitted records and documents that is confidential, commercial and financial. Specific exceptions to disclosure under the Freedom of Information Act, or other statutory protections against disclosure, may apply and preclude disclosure of this information to third parties as provided for in §224.55.

#### **§ 224.133 What must the Director do after a periodic review and evaluation?**



After a periodic review and evaluation, the Director must prepare a written report of the results and send the report to the Designated Tribal Official.

#### **§ 224.134 How often must the Director conduct a periodic review and evaluation?**



The Director must conduct a periodic review and evaluation annually during the first 3 years of a TERA. After the third annual review and evaluation, the Secretary and the tribe may mutually agree to amend the TERA to conduct periodic reviews and evaluations once every 2 years.

#### **§ 224.135 Under what circumstances may the Director conduct additional reviews and evaluations?**



The Director may conduct additional reviews and evaluations:

(a) At a tribe's request;

(b) As part of an investigation undertaken when the tribe notifies the Director of a violation or breach;

(c) As part of an investigation undertaken because of a petition submitted under subpart E of this part;

(d) As follow-up to a determination that harm or the potential for harm to a physical trust asset, previously identified in a periodic review and evaluation, exists; or

(e) As the Secretary determines appropriate to carry out the Secretary's trust responsibilities.

#### **Noncompliance**



**§ 224.136 How will the Director's report address a tribe's noncompliance?**[top](#)

This section applies if the Director conducts a review and evaluation or investigation of a notice of violation of Federal law or the terms of a TERA.

(a) If the Director determines that the tribe has not complied with Federal law or the terms of a TERA, the Director's written report must include a determination of whether the tribe's noncompliance has resulted in harm or the potential for harm to a physical trust asset.

(b) If the Director determines that the tribe's noncompliance may cause harm or has caused harm to a physical trust asset, the Director must also determine whether the noncompliance cause imminent jeopardy to a physical trust asset.

**§ 224.137 What must the Director do if a tribe's noncompliance has resulted in harm or the potential for harm to a physical trust asset?**[top](#)

If, because of the tribe's noncompliance with Federal law or the terms of a TERA, the Director determines that there is harm or the potential for harm to a physical trust asset that does not rise to the level of imminent jeopardy to a physical trust asset, the Director must:

(a) Document the issue in the written report of the review and evaluation;

(b) Report the issue in writing to the tribal governing body;

(c) Report the issue in writing to the Assistant Secretary—Indian Affairs; and

(d) Determine what action, if any, the Secretary must take to protect the physical trust asset, which could include temporary suspension of the activity that resulted in non-compliance with the TERA or other applicable Federal laws or rescinding approval of all or part of the TERA.

**§ 224.138 What must the Director do if a tribe's noncompliance has caused imminent jeopardy to a physical trust asset?**[top](#)

If the Director finds that a tribe's noncompliance with a Federal law or the terms of a TERA has caused imminent jeopardy to a physical trust asset, the Director must:

(a) Immediately notify the tribe by a telephone call to the Designated Tribal Official followed by a written notice by facsimile to the Designated Tribal Official and the tribal governing body of the imminent jeopardy to a physical trust asset. The notice must contain:

(1) A description of the tribe's noncompliance with Federal law or the terms of the TERA;

(2) A description of the physical trust asset and the nature of the imminent jeopardy to a physical trust asset resulting from the tribe's noncompliance; and

(3) An order to the tribe to cease specific conduct or take specific action deemed necessary by the Director to correct any condition that caused the imminent jeopardy to a physical trust asset.

(b) Issue a finding that the tribe's noncompliance with the TERA or a Federal law has caused imminent jeopardy to a physical trust asset.

**§ 224.139 What must a tribe do after receiving a notice of imminent jeopardy to a physical trust asset?**[top](#)

(a) Upon receipt of a notice of imminent jeopardy to a physical trust asset, the tribe must cease specific conduct outlined in the notice or take specific action the Director orders that is necessary to correct any condition causing the imminent jeopardy; and

(b) Within 5 days of receiving a notice of imminent jeopardy to a physical trust asset, the tribe must submit a written response to the Director that:

(1) Responds to the Director's finding that the tribe has failed to comply with a Federal law or the terms of the TERA;

(2) Responds to the Director's finding of imminent jeopardy to a physical trust asset;

(3) Describes the status of the tribe's cessation of specific conduct or specific action the tribe has taken to correct any condition causing imminent jeopardy to a physical trust asset; and

(4) Describes what further actions, if any, the tribe proposes to take to correct any condition, cited in the notice, causing imminent jeopardy to a physical trust asset.

**§ 224.140 What must the Secretary do if the tribe fails to respond to or does not comply with the Director's order?**



[top](#)

If the tribe does not respond to or does not comply with the Director's order under §224.138(a)(3), the Secretary may take any actions the Secretary deems appropriate to protect the physical trust asset, which may include the immediate reassumption of all activities the tribe assumed under the TERA. The procedures in subpart G of this part do not apply to reassumption under this section.

**§ 224.141 What must the Secretary do if the tribe responds to the Director's order?**



[top](#)

(a) If the tribe responds in a timely manner to the Director's order under §224.138, the Secretary must:

(1) Evaluate the tribe's response;

(2) Determine whether or not the tribe has complied with the TERA and the Federal law cited in the notice; and

(3) If the Secretary determines, after reviewing the tribe's response, that the tribe has not complied with the TERA or with a Federal law, the Secretary will determine whether the noncompliance caused imminent jeopardy to a physical trust asset.

(b) If the Secretary determines that the tribe's noncompliance has caused imminent jeopardy to a physical trust asset, the Secretary may:

(1) Order the tribe to take any action the Secretary deems necessary to comply with the TERA or Federal law and to protect the physical trust asset; or

(2) Take any action the Secretary deems necessary to protect the physical trust asset, including reassumption under subpart G of this part.

(c) If the Secretary determines, after reviewing the tribe's response, that the tribe has complied with the TERA and with Federal law, the Secretary will withdraw the Director's order.

(d) The Secretary must base a finding of imminent jeopardy to a physical trust asset on the tribe's non-compliance with a TERA or violation of a Federal law.

**Subpart G—Reassumption**



[top](#)

**§ 224.150 What is the purpose of this subpart?**



[top](#)

This subpart explains when and how the Secretary may reassume all activities included within a TERA without the consent of the tribe.

**§ 224.151 When may the Secretary reassume activities?**



[top](#)

Upon issuing a written finding of imminent jeopardy to a physical trust asset, the Secretary may reassume activities under a TERA in accordance with this subpart. The Secretary may also reassume activities approved under a TERA in response to a petition from an interested party under subpart E of this part. Only the Secretary or the Assistant Secretary—Indian Affairs may reassume activities under a TERA.

**§ 224.152 Must the Secretary always reassume the activities upon a finding of imminent jeopardy to a physical trust asset?**



[top](#)

(a) The Secretary may take whatever actions the Secretary deems necessary to protect the physical trust asset. At the discretion of the Secretary, these actions may include reassumption of the activities a tribe assumed under a TERA.

(b) If the tribe does not respond to or does not comply with the Director's order under §224.138(a)(3), the Secretary must immediately reassume all activities the tribe assumed under the TERA. The notice procedures in this subpart will not apply to such immediate reassumption.

**Notice of Intent To Reassume**



[top](#)

**§ 224.153 Must the Secretary notify the tribe of an intent to reassume the authority granted?**



[top](#)

If the Secretary determines under §224.152 that reassumption is necessary to protect the physical trust asset, the Secretary will issue a written notice to the tribal governing body of the Secretary's intent to reassume.

**§ 224.154 What must a notice of intent to reassume include?**



[top](#)

A notice of intent to reassume must include:

(a) A statement of the reasons for the intended reassumption, including, as applicable, a copy of the Secretary's written finding of imminent jeopardy to a physical trust asset;

(b) A description of specific measures that the tribe must take to correct the violation and any condition that caused the imminent jeopardy to a physical trust asset;

(c) The time period within which the tribe must take the measures to correct the violation of the TERA and any condition that caused the imminent jeopardy to a physical trust asset; and

(d) The effective date of the reassumption, if the tribe does not meet the requirements in paragraphs (b) and (c) of this section.

**§ 224.155 When must a tribe respond to a notice of intent to reassume?**



The tribe must respond to the Director in writing by mail, facsimile, or overnight express within 5 days of receiving the Secretary's notice of intent to reassume. If sent by mail, the tribe must send the response by certified mail, with return receipt requested. The Director will consider the date of the written response as the date it is postmarked.

**§ 224.156 What information must the tribe's response to the notice of intent to reassume include?**



The tribe's response to the notice of intent to reassume must state that:

- (a) The tribe has complied with the Secretary's requirements in the notice of intent to reassume;
- (b) The tribe is taking specified measures to comply with the Secretary's requirements, and when the tribe will complete such measures, if the tribe needs more than 5 days to do so; or
- (c) The tribe will not comply with the Secretary's requirements.

**§ 224.157 How must the Secretary proceed after receiving the tribe's response?**



(a) If the Secretary determines that the tribe's proposed or completed actions to comply with the Secretary's requirements are adequate to correct the violation of the TERA or Federal law and any condition that caused the imminent jeopardy, the Secretary will:

- (1) Notify the tribe of the adequacy of its response in writing; and
- (2) Terminate the reassumption proceedings in writing.

(b) If the Secretary determines that the tribe's proposed or completed actions to comply with the Secretary's requirements are not adequate, then the Secretary will issue a written notice of reassumption.

**§ 224.158 What must the Secretary include in a written notice of reassumption?**



The written notice of reassumption must include:

- (a) A description of the authorities the Secretary is reassuming;
- (b) The reasons for the determination under §224.157(b);
- (c) The effective date of the reassumption; and
- (d) A statement that the decision is a final agency action and is subject to judicial review.

**§ 224.159 How will reassumption affect valid existing rights or lawful actions taken before the effective date of the reassumption?**



Reassumption will not affect valid existing rights that vested before the effective date of the

reassumption or lawful actions the tribe and the Secretary took before the effective date of the reassumption.

#### **§ 224.160 How will reassumption affect a TERA?**



[top](#)

Reassumption of a TERA applies to all of the authority and activities assumed under a TERA. Upon reassumption, the tribe must also return all Departmental resources transferred under the TERA and any relevant records and documents to the Secretary.

#### **§ 224.161 How may reassumption affect the tribe's ability to enter into a new TERA or to modify another TERA to administer additional activities or to assume administration of activities that the Secretary previously reassumed?**



[top](#)

Following reassumption, a tribe may submit a request to enter into a new TERA or modify another TERA to administer additional activities, or assume administration of activities that the Secretary previously reassumed. In reviewing a subsequent tribal request, however, the Secretary may consider the fact that activities were reassumed and any change in circumstances supporting the tribe's request.

### **Subpart H—Rescission**



[top](#)

#### **§ 224.170 What is the purpose of this subpart?**



[top](#)

This subpart explains the process and requirements under which a tribe may rescind a TERA and therefore return to the Secretary all authority and activities assumed under that TERA.

#### **§ 224.171 Who may rescind a TERA?**



[top](#)

Only a tribe may rescind a TERA.

#### **§ 224.172 May a tribe rescind only some of the activities subject to a TERA while retaining a portion of those activities?**



[top](#)

No. A tribe may only rescind a TERA in its entirety, including the authority to approve leases, business agreements and grant rights-of-way for specific energy resource development, not some of the authority or activities subject to the TERA.

#### **§ 224.173 How does a tribe rescind a TERA?**



[top](#)

To rescind a TERA, a tribe must submit to the Secretary a written tribal resolution or other official action of the tribe's governing body approving the voluntary rescission of the TERA. Upon rescission, the tribe must also return all Departmental resources transferred under the TERA and any relevant records and documents.

#### **§ 224.174 When does a voluntary rescission become effective?**



[top](#)

A voluntary rescission becomes effective on the date specified by the Secretary, provided that the date is no more than 90 days after the Secretary receives the tribal resolution or other official action the tribe submits under §224.173.

**§ 224.175 How will rescission affect valid existing rights or lawful actions taken before the rescission?**



[top](#)

Rescission does not affect valid existing rights that vested before the effective date of the rescission or lawful actions the tribe and the Secretary took before the effective date of the rescission.

**Subpart I—General Appeal Procedures**



[top](#)

**§ 224.180 What is the purpose of this subpart?**



[top](#)

The purpose of this subpart is to explain who may appeal Departmental decisions or inaction under this part and the initial administrative appeal processes, and general administrative appeal processes, including how 25 CFR part 2 and 43 CFR part 4 apply, and the effective dates for appeal decisions.

**§ 224.181 Who may appeal Departmental decisions or inaction under this part?**



[top](#)

The following persons or entities may appeal Department decisions or inaction under this part:

- (a) A tribe that is adversely affected by a decision of or inaction by an official of the Department of the Interior under this part;
- (b) A third party who has entered into a lease, right-of-way, or business agreement with a tribe under an approved TERA and is adversely affected by a decision of, or inaction by a Department official under this part; or
- (c) An interested party who is adversely affected by a decision of or inaction by the Director under subpart E of this part, provided that the interested party may appeal only those issues raised in its prior participation under subpart E of this part and may not appeal any other decision rendered or inaction under this part.

**§ 224.182 What is the Initial Appeal Process?**



[top](#)

The initial appeal process is as follows:

- (a) Within 30 days of receiving an adverse decision by the Director or within 30 days after the time period within which the Director is required to act under subpart E, a party that may appeal under this subpart may file an appeal to the Principal Deputy Assistant Secretary-Indian Affairs;
- (b) Within 60 days of receiving an appeal, the Principal Deputy Assistant Secretary—Indian Affairs will review the record and issue a written decision on the appeal; and
- (c) Within 7 days of a decision by the Principal Deputy Assistant Secretary—Indian Affairs, the Secretary will provide a written copy of the decision to the tribe and other participating parties.

**§ 224.183 What other administrative appeals processes also apply?**



The administrative appeal processes in 25 CFR part 2 and 43 CFR part 4, subject to the limitations in §224.184, apply to:

- (a) An interested party's appeal from an adverse decision or inaction by the Principal Deputy Assistant Secretary—Indian Affairs under §224.182; and
- (b) An appeal by a tribe or a person or entity that has entered into a lease, business agreement, or right-of-way from an adverse decision by or the inaction of a Departmental official taken under this part.

**§ 224.184 How do other administrative appeals processes apply?**



The administrative appeals process in 25 CFR part 2 and 43 CFR part 4 are modified, only as they apply to appeals under this part, as set forth in this section.

- (a) The definition of interested party in 25 CFR part 2 and as incorporated in 43 CFR part 4 does not apply to this part.
- (b) The right of persons or entities other than an appealing party to participate in appeals under 25 CFR part 2 and 43 CFR part 4 does not apply to this part, except as permitted under paragraph (c) of this section.
- (c) The only persons or entities, other than appealing parties, under §224.181(a) to (c), who may participate in an appeal under this part are:
  - (1) The Secretary, if an appeal is taken from a decision of the Director or Principal Deputy Assistant Secretary—Indian Affairs;
  - (2) A tribe, which may intervene, appear as an amicus curiae, or otherwise appear in any appeal taken under this part by a person or entity who has entered into a lease, business agreement, or right-of-way with the tribe or by an interested party under this part; or
  - (3) A person or entity that has entered into a lease, business agreement, or right-of-way with a tribe, may intervene, appear as an amicus curiae, or otherwise appear in any appeal taken under this part by the tribe or by an interested party under this part.
- (d) The Secretary does not have an obligation to provide notice and service upon non-appealing persons as provided in 25 CFR part 2 and 43 CFR part 4. The only exception to this principle is that notice and service of all documents must be served consistent with the requirements of 25 CFR part 2 and 43 CFR part 4 on those persons or entities identified in paragraph (c) of this section.

**§ 224.185 When are decisions under this part effective?**



Decisions under subpart I are effective as follows:

- (a) Decisions of the Secretary disapproving a final proposed TERA or a revised final proposed TERA under subpart C of this part, a finding of imminent jeopardy to a physical trust asset under subpart F of this part, and decisions by the Secretary or the Assistant Secretary—Indian Affairs to reassume activities under subpart G of this part are final for the Department. These decisions and findings are effective upon issuance.
- (b) Decisions under this part, other than those in paragraph (a) of this section, that adversely affect a tribe and for which an appeal is pending are not final for the Department and are not effective while the appeal is pending, unless:
  - (1) The tribe had an opportunity for a hearing before the decision was issued;

(2) The tribe had a reasonable amount of time to comply with the TERA after the decision was issued; and

(3) The Interior Board of Indian Appeals (Board), the Secretary, or Assistant Secretary—Indian Affairs issued a written decision that, notwithstanding a reasonable period given the tribe to comply with the TERA, the tribe has failed to take the actions necessary to comply with the TERA.

(c) All other decisions rendered by the Board or the Assistant Secretary—Indian Affairs in an appeal from a Director's decision under subparts E, F, or G of this part are effective when issued.

[Browse Previous](#) | [Browse Next](#)

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### Title 25: Indians

[Browse Previous](#) | [Browse Next](#)

## PART 225—OIL AND GAS, GEOTHERMAL, AND SOLID MINERALS AGREEMENTS

### Section Contents

#### Subpart A—General

- [§ 225.1 Purpose and scope.](#)
- [§ 225.2 Information collection.](#)
- [§ 225.3 Definitions.](#)
- [§ 225.4 Authority and responsibility of the Bureau of Land Management \(BLM\).](#)
- [§ 225.5 Authority and responsibility of the Office of Surface Mining Reclamation and Enforcement \(OSMRE\).](#)
- [§ 225.6 Authority and responsibility of the Minerals Management Service \(MMS\).](#)

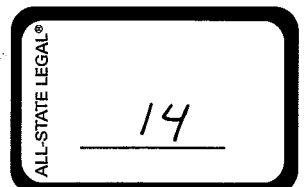
#### Subpart B—Minerals Agreements

- [§ 225.20 Authority to contract.](#)
- [§ 225.21 Negotiation procedures.](#)
- [§ 225.22 Approval of minerals agreements.](#)
- [§ 225.23 Economic assessments.](#)
- [§ 225.24 Environmental studies.](#)
- [§ 225.25 Resolution of disputes.](#)
- [§ 225.26 Auditing and accounting.](#)
- [§ 225.27 Forms and reports.](#)
- [§ 225.28 Approval of amendments to minerals agreements.](#)
- [§ 225.29 Corporate qualifications and requests for information.](#)
- [§ 225.30 Bonds.](#)
- [§ 225.31 Manner of payments.](#)
- [§ 225.32 Permission to start operations.](#)
- [§ 225.33 Assignment of minerals agreements.](#)
- [§ 225.34 \[Reserved\]](#)
- [§ 225.35 Inspection of premises; books and accounts.](#)
- [§ 225.36 Minerals agreement cancellation; Bureau of Indian Affairs notice of noncompliance.](#)
- [§ 225.37 Penalties.](#)
- [§ 225.38 Appeals.](#)
- [§ 225.39 Fees.](#)
- [§ 225.40 Government employees cannot acquire minerals agreements.](#)

**Authority:** Indian Mineral Development Act of 1982, 25 U.S.C. 2101–2108; and 25 U.S.C. 2 and 9.

**Source:** 59 FR 14971, Mar. 30, 1994, unless otherwise noted.

#### **Subpart A—General**





[top](#)

## § 225.1 Purpose and scope.



[top](#)

(a) The regulations in this part, administered by the Bureau of Indian Affairs under the direction of the Secretary of the Interior, govern minerals agreements for the development of Indian-owned minerals entered into pursuant to the Indian Mineral Development Act of 1982, 25 U.S.C. 2101–2108 (IMDA). These regulations are applicable to the lands or interests in lands of any Indian tribe, individual Indian or Alaska native the title to which is held in trust by the United States or is subject to a restriction against alienation imposed by the United States. These regulations are intended to ensure that Indian mineral owners are permitted to enter into minerals agreements that will allow the Indian mineral owners to have more responsibility in overseeing and greater flexibility in disposing of their mineral resources, and to allow development in the manner which the Indian mineral owners believe will maximize their best economic interest and minimize any adverse environmental or cultural impact resulting from such development. Pursuant to section 4 of the IMDA (25 U.S.C. 2103(e)), as part of this greater flexibility, where the Secretary has approved a minerals agreement in compliance with the provisions of 25 U.S.C. chap. 23 and any other applicable provision of law, the United States shall not be liable for losses sustained by a tribe or individual Indian under such minerals agreement. However, as further stated in the IMDA, the Secretary continues to have a trust obligation to ensure that the rights of a tribe or individual Indian are protected in the event of a violation of the terms of any minerals agreement, and to uphold the duties of the United States as derived from the trust relationship and from any treaties, executive orders, or agreements between the United States and any Indian tribe.

(b) The regulations in this part shall become effective and in full force on April 29, 1994, and shall be subject to amendment at any time by the Secretary; *Provided*, that no such regulation that becomes effective after the date of approval of any minerals agreement shall operate to affect the duration of the minerals agreement, the rate of royalty or financial consideration, rental, or acreage unless agreed to by all parties to the minerals agreement.

(c) The regulations of the Bureau of Land Management, the Office of Surface Mining Reclamation and Enforcement, and the Minerals Management Service that are referenced in §§225.4, 225.5, and 225.6 are supplemental to these regulations, and apply to minerals agreements for development of Indian mineral resources unless specifically stated otherwise in this part or in other Federal regulations. To the extent the parties to a minerals agreement are able to provide reasonable provisions satisfactorily addressing the issues of valuation, method of payment, accounting, and auditing, governed by the Minerals Management Service regulations, the Secretary may approve alternate provisions in a minerals agreement.

(d) Nothing in these regulations is intended to prevent Indian tribes from exercising their lawful governmental authority to regulate the conduct of persons, businesses, or minerals operations within their territorial jurisdiction.

## § 225.2 Information collection.



[top](#)

It has been determined by the Office of Management and Budget that the Information Collection Requirements contained in part 225 do not require review under the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.* ).

## § 225.3 Definitions.



[top](#)

As used in this part, the following terms have the specified meaning except where otherwise indicated.

*Area Director* means the Bureau of Indian Affairs Official in charge of an Area Office.

*Assistant Secretary—Indian Affairs* means the Assistant Secretary—Indian Affairs of the Department of the Interior, a designee of the Secretary of the Interior who may be specifically authorized by the Secretary to disapprove minerals agreements (25 U.S.C. 2103(d)) and to issue orders of cessation and/or minerals agreement cancellations as final orders of the Department.

*Authorized Officer* means any employee of the Bureau of Land Management authorized by law or by lawful delegation of authority to perform the duties described herein and in 43 CFR parts 3160, 3180, 3260, 3280, 3480 and 3590.

*Director's Representative* means the Office of Surface Mining Reclamation and Enforcement Director's Representative authorized by law or by lawful delegation of authority to perform the duties described in 30 CFR part 750 and 25 CFR part 216.

*Gas* means any fluid, either combustible or noncombustible, that is produced in a natural state from the earth and that maintains a gaseous or rarefied state at ordinary temperature and pressure conditions.

*Geothermal resources* means: (1) All products of geothermal processes, including indigenous steam, hot water, and hot brines;

(2) Steam and other gases, hot water, and hot brines, resulting from water, gas, or other fluids artificially introduced into geothermal formations;

(3) Heat or other associated energy found in geothermal formations; and

(4) Any by-product derived therefrom.

*In the best interest of the Indian mineral owner* refers to the standards to be applied by the Secretary in considering whether to take administrative action affecting the interests of an Indian mineral owner. In considering whether it is "in the best interest of the Indian mineral owner" to take a certain action (such as approval of a minerals agreement or a unitization or communitization agreement) the Secretary shall consider any relevant factor, including, but not limited to: economic considerations, such as date of lease or minerals agreement expiration; probable financial effects on the Indian mineral owner; need for change in the terms of the existing minerals agreement; marketability of mineral products; and potential environmental, social and cultural effects.

*Indian lands* means any lands or interests in lands owned by any individual Indian or Alaska Native, Indian tribe, band, nation, pueblo, community, rancheria, colony, or other group, the title to which is held in trust by the United States or is subject to a restriction against alienation imposed by the United States.

*Indian mineral owner* means any individual Indian or Alaska Native, or Indian tribe, band, nation, pueblo, community, rancheria, colony, or other group that owns a mineral interest in oil and gas, geothermal resources or solid minerals, title to which is held in trust by the United States or is subject to a restriction against alienation imposed by the United States.

*Indian surface owner* means any individual Indian or Alaska Native, or Indian tribe, band, nation, pueblo, community, rancheria, colony, or other group that owns the surface estate in land the title to which is held in trust by the United States or is subject to a restriction against alienation imposed by the United States.

*Indian tribe* means any Indian tribe, band, nation, pueblo, community, rancheria, colony, or other group that owns land or interests in land the title to which is held in trust by the United States or is subject to a restriction against alienation imposed by the United States.

*Individual Indian* means any individual Indian or Alaska Native who owns land or interests in land the title to which is held in trust by the United States or is subject to a restriction against alienation imposed by the United States.

*Minerals* includes both metalliferous and non-metalliferous minerals; all hydrocarbons, including oil and gas, coal and lignite of all ranks; geothermal resources; and includes but is not limited to sand, gravel, pumice, cinders, granite, building stone, limestone, clay, silt, or any other energy or non-energy mineral.

*Minerals agreement* means any joint venture, operating, production sharing, service, managerial, lease (other than a lease entered into pursuant to the Act of May 11, 1938, or the Act of March 3, 1909), contract, or other minerals agreement; or any amendment, supplement or other modification of such minerals agreement, providing for the exploration for, or extraction, processing, or other development of minerals in which an Indian mineral owner owns a beneficial or restricted interest, or providing for the sale or other disposition of the production or products of such minerals.

*Minerals Management Service official* means any employee of the Minerals Management Service authorized by law or by lawful delegation of authority to perform the duties described in 30 CFR chapter II, subchapters A and C.

*Mining* means the science, technique, and business of mineral development, including, but not limited to: opencast work, underground work, in-situ leaching, or other methods directed to severance and treatment of minerals; however, when sand, gravel, pumice, cinders, granite, building stone, limestone, clay or silt is the subject mineral, an enterprise is considered "mining" only if the extraction of such a mineral exceeds 5,000 cubic yards in any given year.

*Oil* means all non-gaseous hydrocarbon substances other than coal, oil shale, or gilsonite (including all vein-type solid hydrocarbons). Oil includes liquefiable hydrocarbon substances such as drip gasoline and other natural condensates recovered or recoverable in a liquid state from produced gas without resorting to a manufacturing process.

*Operator* means a person, proprietorship, partnership, corporation, or other business entity that has entered into an approved minerals agreement under the authority of the Indian Mineral Development Act of 1982, or who has been assigned an obligation to make royalty or other payments required by the minerals agreement.

*Secretary* means the Secretary of the Interior or an authorized representative, except that as used in §225.22 (e) and (f) the authorized representative may only be the Assistant Secretary for Indian Affairs (25 U.S.C. 2103(d)).

*Solid minerals* means all minerals excluding oil, gas, and geothermal resources.

*Superintendent* means the Bureau of Indian Affairs official in charge of an agency office.

#### **§ 225.4 Authority and responsibility of the Bureau of Land Management (BLM).**



[top](#)

The functions of the Bureau of Land Management are found in 43 CFR part 3160—Onshore Oil and Gas Operations, 43 CFR part 3180—Onshore Oil and Gas Unit Agreements: Unproven Areas, 43 CFR part 3260—Geothermal Resources Operations, 43 CFR part 3280—Geothermal Resources Unit Agreements: Unproven Areas, 43 CFR part 3480—Coal Exploration and Mining Operations, and 43 CFR part 3590—Solid Minerals (Other Than Coal) Exploration and Mining Operations. These functions include, but are not limited to, resource evaluation, approval of drilling permits, approval of mining, reclamation, and production plans, mineral appraisals, inspection and enforcement, and production verification. These regulations, as amended, apply to minerals agreements approved under this part.

#### **§ 225.5 Authority and responsibility of the Office of Surface Mining Reclamation and Enforcement (OSMRE).**



[top](#)

The OSMRE is the regulatory authority for surface coal mining and reclamation operations on Indian lands pursuant to the Surface Mining Control and Reclamation Act of 1977 (30 U.S.C. 1201 *et seq.* ). The relevant regulations for surface mining and reclamation operations are found in 30 CFR part 750 and 25 CFR part 216. These regulations, as amended, apply to minerals agreements approved under this part.

#### **§ 225.6 Authority and responsibility of the Minerals Management Service (MMS).**



[top](#)

The functions of the MMS for reporting, accounting, and auditing are found in 30 CFR chapter II, subchapters A and C. These regulations, unless specifically stated otherwise in this part or in other regulations, apply to all minerals agreements approved under this part. To the extent the parties to a minerals agreement are able to provide reasonable provisions satisfactorily addressing the issues or functions governed by the MMS regulations relating to valuation of mineral product, method of payment, accounting procedures, and auditing procedures, the Secretary may approve alternate provisions in a minerals agreement.

#### **Subpart B—Minerals Agreements**



[top](#)

**§ 225.20 Authority to contract.**



[top](#)

(a) Any Indian tribe, subject to the approval of the Secretary and any limitation or provision contained in its constitution or charter, may enter into a minerals agreement with respect to mineral resources in which the tribe owns a beneficial or restricted interest.

(b) Any individual Indian owning a beneficial or restricted interest in mineral resources may include those resources in a tribal minerals agreement subject to the concurrence of the parties and a finding by the Secretary that inclusion of the resources is in the best interest of the individual Indian mineral owner.

**§ 225.21 Negotiation procedures.**



[top](#)

(a) An Indian mineral owner that wishes to enter into a minerals agreement may ask the Secretary for advice, assistance, and information during the negotiation process. The Secretary shall provide advice, assistance, and information to the extent allowed by available resources.

(b) No particular form of minerals agreement is prescribed. In preparing the minerals agreement the Indian mineral owner shall, if applicable, address provisions including, but not limited to, the following:

(1) A general statement identifying the parties to the minerals agreement, the legal description of the lands, including, if applicable, rock intervals or thicknesses subject to the minerals agreement, and the purposes of the minerals agreement;

(2) A statement setting forth the duration of the minerals agreement;

(3) A statement providing indemnification to the Indian mineral owner(s) and the United States from all claims, liabilities and causes of action that may be made by persons not a party to the minerals agreement;

(4) Provisions setting forth the obligations of the contracting parties;

(5) Provisions describing the methods of disposition of production;

(6) Provisions outlining the method of payment and amount of compensation to be paid;

(7) Provisions establishing accounting and mineral valuation procedures;

(8) Provisions establishing operating and management procedures;

(9) Provisions establishing any limitations on assignment of interests, including any right of first refusal by the Indian mineral owner in the event of a proposed assignment;

(10) Bond requirements;

(11) Insurance requirements;

(12) Provisions establishing audit procedures;

(13) Provisions for resolving disputes;

(14) A force majeure provision;

(15) Provisions describing the rights of the parties to terminate or suspend the minerals agreement, and the procedures to be followed in the event of termination or suspension;

(16) Provisions describing the nature and schedule of the activities to be conducted by the parties;

(17) Provisions describing the proposed manner and time of performance of future abandonment,

reclamation and restoration activities;

(18) Provisions for reporting production and sales;

(19) Provisions for unitizing or communitizing of lands included in a minerals agreement for the purpose of promoting conservation and efficient utilization of natural resources;

(20) Provisions for protection of the minerals agreement lands from drainage and/or unauthorized taking of mineral resources; and

(21) Provisions for record keeping.

(c) In order to avoid delays in obtaining approval, the Indian mineral owner is encouraged to confer with the Secretary prior to formally executing the minerals agreement, and seek advice as to whether the minerals agreement appears to satisfy the requirements of §225.22, or whether additions or corrections may be required in order to obtain Secretarial approval.

(d) The executed minerals agreement, together with a copy of a tribal resolution authorizing tribal officers to enter into the minerals agreement, shall be forwarded by the tribal representative to the appropriate Superintendent, or in the absence of a Superintendent to the Area Director, for approval.

#### **§ 225.22 Approval of minerals agreements.**



(a) A minerals agreement submitted for approval pursuant to §225.21(d) shall be approved or disapproved within:

(1) One hundred and eighty (180) days after submission, or

(2) Sixty (60) days after compliance, if required, with section 102(2)(C) of the National Environmental Policy Act of 1969 (42 U.S.C. 4332(2)(C)) or any other requirement of Federal law, whichever is later.

(b) At least thirty (30) days prior to approval or disapproval of any minerals agreement, the affected Indian mineral owners shall be provided with written findings forming the basis of the Secretary's intent to approve or disapprove the minerals agreement.

(1) The written findings shall include an environmental study which meets the requirements of §225.24 and an economic assessment, as described in §225.23.

(2) The Secretary shall include in the written findings any recommendations for changes to the minerals agreement needed to qualify it for approval.

(3) The 30-day period shall commence to run as of the date the written findings are received by the Indian mineral owner.

(4) Notwithstanding any other law, such findings and all projections, studies, data or other information (other than the environmental study required by §225.24) possessed by the Department of the Interior regarding the terms and conditions of the minerals agreement; the financial return to the Indian parties thereto; the extent, nature, value or disposition of the mineral resources; or the production, products or proceeds thereof, shall be held by the Department of the Interior as privileged and proprietary information of the affected Indian mineral owners. The letter containing the written findings should be headed with: PRIVILEGED PROPRIETARY INFORMATION OF THE (names of Indian mineral owners).

(c) A minerals agreement shall be approved if, at the Secretary's discretion, it is determined that the following conditions are met:

(1) The minerals agreement is in the best interest of the Indian mineral owner;

(2) The minerals agreement does not have adverse cultural, social, or environmental impacts sufficient to outweigh its expected benefits to the Indian mineral owners; and,

(3) The minerals agreement complies with the requirements of this part and all other applicable regulations and the provisions of applicable Federal law.

(d) The determinations required by paragraph (c) of this section shall be based on the written findings required by paragraph (b) and paragraphs (b)(1) through (b)(4), inclusive, of this section. The question of "best interest" within the meaning of paragraph (c)(1) of this section shall be determined by the Secretary based on information obtained from the parties, and any other information considered relevant by the Secretary, including, but not limited to, a review of comparable contemporary contractual arrangements or offers for the development of similar mineral resources received by Indian mineral owners, by non-Indian mineral owners, or by the Federal Government, insofar as that information is readily available.

(e) If a Superintendent or Area Director believes that a minerals agreement should not be approved, a written statement of the reasons why the minerals agreement should not be approved shall be prepared and forwarded, together with the minerals agreement, the written findings required by paragraph (b) and subparagraphs (b)(1) through (b)(4), inclusive, of this section, and all other pertinent documents, to the Secretary for a decision with a copy to the affected Indian mineral owner.

(f) The Secretary shall review any minerals agreement referred with a recommendation that it be disapproved, and the Secretary's decision to disapprove a minerals agreement shall be deemed a final Federal agency action (25 U.S.C. 2103(d)).

#### **§ 225.23 Economic assessments.**



[top](#)

The Secretary shall prepare or cause to be prepared an economic assessment that shall address, among other things:

- (a) Whether there are assurances in the minerals agreement that operations shall be conducted with appropriate diligence;
- (b) Whether the production royalties or other form of return on mineral resources is adequate; and
- (c) Whether the minerals agreement is likely to provide the Indian mineral owner with a return on the production comparable to what the owner might otherwise obtain through competitive bidding, when such a comparison can reasonably be made.

#### **§ 225.24 Environmental studies.**



[top](#)

(a) The Secretary shall ensure that all environmental studies are prepared as required by the National Environmental Policy Act of 1969 (NEPA) and the regulations promulgated by the Council on Environmental Quality (CEQ) found at 40 CFR parts 1500–1508.

(b) The Secretary shall ensure that all necessary surveys are performed and clearances obtained in accordance with 36 CFR parts 60, 63, and 800 and with the requirements of the Archaeological and Historic Preservation Act (16 U.S.C. 469 *et seq.*), the National Historic Preservation Act (16 U.S.C. 470 *et seq.*), the American Indian Religious Freedom Act (42 U.S.C. 1996), and Executive Order 11593 (3 CFR 1971–1975 Comp., p. 559, May 13, 1971). If these surveys indicate that a mineral development will have an adverse effect on a property listed on or eligible for listing on the National Register of Historic Places, the Secretary shall:

- (1) Seek the comments of the Advisory Council on Historic Preservation, in accordance with 36 CFR part 800;
- (2) Ensure that the property is avoided, that the adverse effect is mitigated, or that appropriate excavations or other related research is conducted; and
- (3) Ensure that complete data describing the historic property is preserved.

#### **§ 225.25 Resolution of disputes.**



[top](#)

A minerals agreement shall contain provisions for resolving disputes that may arise between the parties. However, no such provision shall limit the Secretary's authority or ability to ensure that the rights of an Indian mineral owner are protected in the event of a violation of the provisions of the minerals agreement by any other party to the minerals agreement.

#### **§ 225.26 Auditing and accounting.**



[top](#)

The Secretary may conduct audits relating to the scope, nature and extent of compliance with the minerals agreement and with applicable regulations and orders to lessees, operators, revenue payors, and other persons with rental, royalty, net profit share and other payment requirements arising from the provisions of a minerals agreement. Procedures and standards used for accounting and auditing of minerals agreements will be in accordance with audit standards established by the Comptroller General of the United States, in "Standards for Auditing of Governmental Organizations, Programs, Activities, and Functions, 1981," and standards established by the American Institute of Certified Public Accountants.

#### **§ 225.27 Forms and reports.**



[top](#)

Any forms required to be filed pursuant to a minerals agreement may be obtained from the Superintendent or Area Director. Prescribed forms for filing geothermal production reports required by the BLM (43 CFR part 3260, §§3264.1, 3264.2-4 and 3264.2-5) may be obtained from the Superintendent, Area Director, or the Authorized Officer. Applicable reports required by the MMS shall be filed using the forms prescribed in 30 CFR part 210, which are available from MMS. Guidance on how to prepare and submit required information, collection reports, and forms to MMS is available from: Minerals Management Service, Attention: Lessee (or Reporter) Contact Branch, P.O. Box 5760, Denver, Colorado 80217. Additional reporting requirements may be required by the Secretary.

#### **§ 225.28 Approval of amendments to minerals agreements.**



[top](#)

An amendment, modification or supplement to a minerals agreement entered into pursuant to the regulations in this part, whether the minerals agreement was approved before or after the effective date of these regulations, must be approved in writing by all parties before being submitted to the Secretary for approval. The provisions of §225.22 apply to approvals of amendments, modifications, or supplements to minerals agreements entered into under the regulations in this part. However, amendments, modifications, or supplements that do not substantially alter or affect the factors listed in §225.22(c), may be approved by referencing materials previously submitted for the initial review and approval of the minerals agreement. The Secretary may approve an amendment, modification, or supplement if it is determined that the underlying minerals agreement, as amended, modified, or supplemented meets the criteria for approval set forth in §225.22(c).

#### **§ 225.29 Corporate qualifications and requests for information.**



[top](#)

- (a) The signing in a representative capacity of minerals agreements or assignments, bonds, or other instruments required by a minerals agreement or these regulations, constitutes certification that the individual signing (except a surety agent) is authorized to act in such a capacity. An agent for a surety shall furnish a power of attorney.
- (b) A prospective corporate operator proposing to acquire an interest in a minerals agreement shall have on file with the Superintendent a statement showing:
  - (1) The State(s) in which the corporation is incorporated, and a notarized statement that the corporation is authorized to hold such interests in the State where the land described in the minerals agreement is situated; and
  - (2) A notarized statement that it has power to conduct all business and operations as described in the minerals agreement.

(c) The Secretary may, either before or after the approval of a minerals agreement, assignment, or bond, call for any reasonable additional information necessary to carry out the regulations in this part, or other applicable laws and regulations.

#### § 225.30 Bonds.



(a) Bonds required by provisions of a minerals agreement should be in an amount sufficient to ensure compliance with all of the requirements of the minerals agreement and the statutes and regulations applicable to the minerals agreement. Surety bonds shall be issued by a qualified company approved by the Department of the Treasury (see Department of the Treasury Circular No. 570).

(b) An operator may file a \$75,000 bond for all geothermal, mining, or oil and gas minerals agreements in any one State, which may also include areas on that part of an Indian reservation extending into any contiguous State. Statewide bonds shall be filed for approval with the Secretary.

(c) An operator may file a \$150,000 bond for full nationwide coverage to cover all geothermal or oil and gas minerals agreements without geographic or acreage limitation to which the operator is or may become a party. Nationwide bonds shall be filed for approval with the Secretary.

(d) Personal bonds shall be accompanied by:

(1) Certificate of deposit issued by a financial institution, the deposits of which are Federally insured, explicitly granting the Secretary full authority to demand immediate payment in case of default in the performance of the provisions and conditions of the minerals agreement. The certificate shall explicitly indicate on its face that Secretarial approval is required prior to redemption of the certificate of deposit by any party;

(2) Cashier's check;

(3) Certified check;

(4) Negotiable Treasury securities of the United States of a value equal to the amount specified in the bond. Negotiable Treasury securities shall be accompanied by a proper conveyance to the Secretary of full authority to sell such securities in case of default in the performance of the provisions and conditions of a minerals agreement; or

(5) Letter of credit issued by a financial institution authorized to do business in the United States and whose deposits are Federally insured, and identifying the Secretary as sole payee with full authority to demand immediate payment in the case of default in the performance of the provisions and conditions of a minerals agreement.

(i) The letter of credit shall be irrevocable during its term.

(ii) The letter of credit shall be payable to the Bureau of Indian Affairs on demand, in part or in full, upon receipt from the Secretary of a notice of attachment stating the basis thereof (e.g., default in compliance with the minerals agreement provisions and conditions or failure to file a replacement in accordance with subparagraph (d)(5)(v) of this section).

(iii) The initial expiration date of the letter of credit shall be at least one (1) year following the date it is filed in the proper Bureau of Indian Affairs office.

(iv) The letter of credit shall contain a provision for automatic renewal for periods of not less than one (1) year in the absence of notice to the proper Bureau of Indian Affairs office at least ninety (90) days prior to the originally stated or any extended expiration date.

(v) A letter of credit used as security for any minerals agreement upon which operations have taken place and final approval for abandonment has not been given, or as security for a statewide or nationwide bond, shall be forfeited and shall be collected by the Secretary if not replaced by other suitable bond or letter of credit at least thirty (30) days before its expiration date.

(e) The required amount of a bond may be increased in any particular case at the discretion of the Secretary.

[59 FR 14971, Mar. 30, 1994; 60 FR 10474, Feb. 24, 1995]

#### **§ 225.31 Manner of payments.**



Unless specified otherwise in the minerals agreement, after production has been established, all payments due for royalties, bonuses, rentals and other payments under a minerals agreement shall be made to the Secretary or such other party as may be designated, and shall be made at such time as provided in 30 CFR chapter II, subchapters A and C. Prior to production, all bonus and rental payments, shall be made to the Superintendent or Area Director.

#### **§ 225.32 Permission to start operations.**



(a) No exploration, drilling, or mining operations are permitted on any Indian lands before the Secretary has granted written approval of the minerals agreement pursuant to the regulations. After a minerals agreement is approved, written permission to start operations must be secured by applying for the permits referred to in paragraph (b) of this section.

(b) Applicable permits in accordance with rules and regulations in 30 CFR part 750, 43 CFR parts 3160, 3260, 3480, 3590, and Orders or Notices to Lessees (NTL) issued thereunder shall be required before actual operations are conducted on the minerals agreement acreage.

#### **§ 225.33 Assignment of minerals agreements.**



An assignment of a minerals agreement, or any interest therein, shall not be valid without the approval of the Secretary and, if required in the minerals agreement, the Indian mineral owner. The assignee must be qualified to hold the minerals agreement and shall furnish a satisfactory bond conditioned on the faithful performance of the covenants and conditions thereof as stipulated in the minerals agreement. A fully executed copy of the assignment shall be filed with the Secretary within five (5) working days after execution by all parties. The Secretary may permit the release of any bonds executed by the assignor upon submission of satisfactory bonds to the Bureau of Indian Affairs by the assignee, and a determination that the assignor has satisfied all accrued obligations.

#### **§ 225.34 [Reserved]**



#### **§ 225.35 Inspection of premises; books and accounts.**



(a) Operators shall allow Indian mineral owners, their authorized representatives, or any authorized representatives of the Secretary to enter all parts of the minerals agreement area for the purpose of inspection. Operators shall keep a full and correct account of all operations and submit all related reports required by the minerals agreement and applicable regulations. Books and records shall be available for inspection during regular business hours.

(b) Operators shall provide records to the Minerals Management Service (MMS) in accordance with MMS regulations and guidelines. All records pertaining to a minerals agreement shall be maintained by an operator in accordance with 30 CFR part 212.

(c) Operators shall provide records to the Authorized Officer in accordance with BLM regulations and guidelines.

(d) Operators shall provide records to the Director's Representative in accordance with OSMRE regulations and guidelines.

**§ 225.36 Minerals agreement cancellation; Bureau of Indian Affairs notice of noncompliance.**



[top](#)

(a) If the Secretary determines that an operator has failed to comply with the regulations in this part; other applicable laws or regulations; the terms of the minerals agreement; the requirements of an approved exploration, drilling or mining plan; Secretarial orders; or the orders of the Authorized Officer, the Director's Representative, or the MMS Official, the Secretary may:

(1) Serve a notice of noncompliance; or

(2) Serve a notice of proposed cancellation.

(b) The notice of noncompliance shall specify in what respect the operator has failed to comply with the requirements referenced in paragraph (a), and shall specify what actions, if any, must be taken to correct the noncompliance.

(c) The notice of proposed cancellation shall set forth the reasons why cancellation is proposed.

(d) The notice of proposed cancellation or noncompliance shall be served upon the operator by delivery in person or by certified mail to the operator at the operator's last known address. When certified mail is used, the date of service shall be deemed to be when received or five (5) working days after the date it is mailed, whichever is earlier.

(e) The operator shall have thirty (30) days (or such longer time as specified in the notice) from the date that the Bureau of Indian Affairs notice of proposed cancellation or noncompliance is served to respond, in writing, to the Superintendent or Area Director actually issuing the notice.

(f) If an operator fails to take any action that may be prescribed in the notice of proposed cancellation, fails to file a timely written response to the notice, or files a written response that does not, in the discretion of the Secretary, adequately justify the operator's failure to comply, then the Secretary may cancel the minerals agreement, specifying the basis for the cancellation. Cancellation of a minerals agreement shall not relieve the operator of any continuing obligation under the minerals agreement.

(g) If an operator fails to take corrective action or to file a timely written response adequately justifying the operator's actions pursuant to a notice of noncompliance, the Secretary may issue an order of cessation. If the operator fails to comply with the order of cessation, or fails to timely file an appeal of the order of cessation pursuant to paragraph (k) of this section, the Secretary may issue an order of minerals agreement cancellation.

(h) This section does not limit any other remedies of the Indian mineral owner as set forth in the minerals agreement.

(i) Nothing in this section is intended to limit the authority of the Authorized Officer, the Director's Representative, or the MMS Official to take any enforcement action authorized pursuant to statute or regulation.

(j) The Authorized Officer, the Director's Representative, the MMS Official, and the Superintendent or Area Director should consult with one another before taking any enforcement actions.

(k) If orders of cessation or minerals agreement cancellation issued pursuant to this section are issued by a designee of the Secretary other than the Assistant Secretary for Indian Affairs, the orders may be appealed under 25 CFR part 2. If the orders are issued by the Secretary or the Assistant Secretary for Indian Affairs, and not one of their delegates or subordinates, the orders are the final orders of the Department.

**§ 225.37 Penalties.**



[top](#)

(a) In addition to or in lieu of cancellation under §225.36, violations of the terms and conditions of any minerals agreement, the regulations in this part, other applicable laws or regulations, or failure to comply with a notice of noncompliance or a cessation order issued by the Secretary may subject an operator to

a penalty of not more than \$1,000 per day for each day that such a violation or noncompliance continues beyond the time limits prescribed for corrective action.

(b) A notice of a proposed penalty shall be served on the operator either personally or by certified mail to the operator at the operator's last known address. The date of service by certified mail shall be deemed to be the date received or five (5) working days after the date mailed, whichever is earlier.

(c) The notice shall specify the nature of the violation and the proposed penalty, and shall specifically advise the operator of the operator's right to either request a hearing within thirty (30) days of receipt of the notice or pay the proposed penalty. Hearings shall be held before the Superintendent or Area Director whose findings shall be conclusive, unless an appeal is taken pursuant to 25 CFR part 2. If within thirty (30) days of receipt of the notice of proposed penalty the operator has not requested a hearing or paid the amount of the proposed penalty, a final notice of penalty shall be served.

(d) If the person served with a notice of proposed penalty requests a hearing, penalties shall accrue each day the violations or noncompliance set forth in the notice continue beyond the time limits presented for corrective action. The Secretary may issue a written suspension of the requirement to correct the violations pending completion of the hearings provided by this section only upon a determination, at the discretion of the Secretary, that such a suspension will not be detrimental to the Indian mineral owner and upon submission and acceptance of a bond deemed adequate to indemnify the Indian mineral owner from loss or damage. The amount of the bond must be sufficient to cover the cost of correcting the violations set forth in the notice or any disputed amounts plus accrued penalties and interest.

(e) Payment of penalties in full more than ten (10) days after a final decision imposing a penalty shall subject the operator to late payment charges. Late payment charges shall be calculated on the basis of a percentage assessment rate of the amount unpaid per month for each month or fraction thereof until payment is received by the Secretary. In the absence of a specific minerals agreement provision prescribing a different rate, the interest rate on late payments and underpayments shall be a rate applicable under section 6621(a)(2) of the Internal Revenue Code of 1954. Interest shall be charged only on the amount of payment not received and only for the number of days the payment is late.

(f) None of the provisions of this section shall be interpreted as:

(1) Replacing or superseding the independent authority of the Authorized Officer, the Director's Representative, or the MMS Official to impose penalties under applicable statutory or regulatory authorities;

(2) Replacing, superseding, or replicating any penalty provision in the terms and conditions of a minerals agreement approved by the Secretary pursuant to this part; or

(3) Authorizing the imposition of a penalty for violations of minerals agreement provisions for which the Authorized Officer, Director's Representative, or MMS Official has either statutory or regulatory authority to assess a penalty.

#### **§ 225.38 Appeals.**



[top](#)

Appeals from decisions of Officials of the Bureau of Indian Affairs under this part may be taken pursuant to 25 CFR part 2.

#### **§ 225.39 Fees.**



[top](#)

(a) Unless otherwise authorized by the Secretary, each minerals agreement or assignment thereof, shall be accompanied by a filing fee of \$75.00 at the time of filing.

(b) An Indian mineral owner shall not be required to pay a filing fee if the Indian mineral owner, pursuant to a provision in the existing minerals agreement, acquires an additional interest in that minerals agreement.

#### **§ 225.40 Government employees cannot acquire minerals agreements.**



U.S. Government employees are prevented from acquiring any interest(s) in minerals agreements by the provisions of 25 CFR part 140 and 43 CFR part 20 pertaining to conflicts of interest and ownership of an interest in trust land.

[Browse Previous](#) | [Browse Next](#)

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### Title 30: Mineral Resources

[Browse Previous](#) | [Browse Next](#)

#### PART 202—ROYALTIES

##### Section Contents

##### Subpart A—General Provisions [Reserved]

##### Subpart B—Oil, Gas, and OCS Sulfur, General

§ 202.51 Scope and definitions.

§ 202.52 Royalties.

§ 202.53 Minimum royalty.

##### Subpart C—Federal and Indian Oil

§ 202.100 Royalty on oil.

§ 202.101 Standards for reporting and paying royalties.

##### Subpart D—Federal Gas

§ 202.150 Royalty on gas.

§ 202.151 Royalty on processed gas.

§ 202.152 Standards for reporting and paying royalties on gas.

##### Subpart E—Solid Minerals, General [Reserved]

##### Subpart F—Coal

§ 202.250 Overriding royalty interest.

##### Subpart G—Other Solid Minerals [Reserved]

##### Subpart H—Geothermal Resources

§ 202.350 Scope and definitions.

§ 202.351 Royalties on geothermal resources.

§ 202.352 Minimum royalty.

§ 202.353 Measurement standards for reporting and paying royalties and direct use fees.

##### Subpart I—OCS Sulfur [Reserved]

##### Subpart J—Gas Production From Indian Leases

§ 202.550 How do I determine the royalty due on gas production?

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15

- § 202.551 How do I determine the volume of production for which I must pay royalty if my lease is not in an approved Federal unit or communitization agreement (AFA)?  
§ 202.552 How do I determine how much royalty I must pay if my lease is in an approved Federal unit or communitization agreement (AFA)?  
§ 202.553 How do I value my production if I take more than my entitled share?  
§ 202.554 How do I value my production that I do not take if I take less than my entitled share?  
§ 202.555 What portion of the gas that I produce is subject to royalty?  
§ 202.556 How do I determine the value of avoidably lost, wasted, or drained gas?  
§ 202.557 Must I pay royalty on insurance compensation for unavoidably lost gas?  
§ 202.558 What standards do I use to report and pay royalties on gas?
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**Authority:** 5 U.S.C. 301 *et seq.* ; 25 U.S.C. 396 *et seq.*, 396a *et seq.*, 2101 *et seq.* ; 30 U.S.C. 181 *et seq.*, 351 *et seq.*, 1001 *et seq.* ; 1701 *et seq.* ; 31 U.S.C. 9701; 43 U.S.C. 1301 *et seq.* ; 1331 *et seq.*, 1801 *et seq.*

#### **Subpart A—General Provisions [Reserved]**



#### **Subpart B—Oil, Gas, and OCS Sulfur, General**



**Source:** 53 FR 1217, Jan. 15, 1988, unless otherwise noted.

#### **§ 202.51 Scope and definitions.**



(a) This subpart is applicable to Federal and Indian (Tribal and allotted) oil and gas leases (except leases on the Osage Indian Reservation, Osage County, Oklahoma) and OCS sulfur leases.

(b) The definitions in subparts B, C, D, and E, of part 206 of this title are applicable to subparts B, C, D, and J of this part.

[53 FR 1217, Jan. 15, 1988, as amended at 64 FR 43513, Aug. 10, 1999]

#### **§ 202.52 Royalties.**



(a) Royalties on oil, gas, and OCS sulfur shall be at the royalty rate specified in the lease, unless the Secretary, pursuant to the provisions of the applicable mineral leasing laws, reduces, or in the case of OCS leases, reduces or eliminates, the royalty rate or net profit share set forth in the lease.

(b) For purposes of this subpart, the use of the term *royalty(ies)* includes the term *net profit share(s)*.

#### **§ 202.53 Minimum royalty.**



For leases that provide for minimum royalty payments, the lessee shall pay the minimum royalty as specified in the lease.

#### **Subpart C—Federal and Indian Oil**



[top](#)

## § 202.100 Royalty on oil.



[top](#)

(a) Royalties due on oil production from leases subject to the requirements of this part, including condensate separated from gas without processing, shall be at the royalty rate established by the terms of the lease. Royalty shall be paid in value unless MMS requires payment in-kind. When paid in value, the royalty due shall be the value, for royalty purposes, determined pursuant to part 206 of this title multiplied by the royalty rate in the lease.

(b)(1) All oil (except oil unavoidably lost or used on, or for the benefit of, the lease, including that oil used off-lease for the benefit of the lease when such off-lease use is permitted by the MMS or BLM, as appropriate) produced from a Federal or Indian lease to which this part applies is subject to royalty.

(2) When oil is used on, or for the benefit of, the lease at a production facility handling production from more than one lease with the approval of the MMS or BLM, as appropriate, or at a production facility handling unitized or communitized production, only that proportionate share of each lease's production (actual or allocated) necessary to operate the production facility may be used royalty-free.

(3) Where the terms of any lease are inconsistent with this section, the lease terms shall govern to the extent of that inconsistency.

(c) If BLM determines that oil was avoidably lost or wasted from an onshore lease, or that oil was drained from an onshore lease for which compensatory royalty is due, or if MMS determines that oil was avoidably lost or wasted from an offshore lease, then the value of that oil shall be determined in accordance with 30 CFR part 206.

(d) If a lessee receives insurance compensation for unavoidably lost oil, royalties are due on the amount of that compensation. This paragraph shall not apply to compensation through self-insurance.

(e)(1) In those instances where the lessee of any lease committed to a federally approved unitization or communitization agreement does not actually take the proportionate share of the agreement production attributable to its lease under the terms of the agreement, the full share of production attributable to the lease under the terms of the agreement nonetheless is subject to the royalty payment and reporting requirements of this title. Except as provided in paragraph (e)(2) of this section, the value, for royalty purposes, of production attributable to unitized or communitized leases will be determined in accordance with 30 CFR part 206. In applying the requirements of 30 CFR part 206, the circumstances involved in the actual disposition of the portion of the production to which the lessee was entitled but did not take shall be considered as controlling in arriving at the value, for royalty purposes, of that portion as though the person actually selling or disposing of the production were the lessee of the Federal or Indian lease.

(2) If a Federal or Indian lessee takes less than its proportionate share of agreement production, upon request of the lessee MMS may authorize a royalty valuation method different from that required by paragraph (e)(1) of this section, but consistent with the purposes of these regulations, for any volumes not taken by the lessee but for which royalties are due.

(3) For purposes of this subchapter, all persons actually taking volumes in excess of their proportionate share of production in any month under a unitization or communitization agreement shall be deemed to have taken ratably from all persons actually taking less than their proportionate share of the agreement production for that month.

(4) If a lessee takes less than its proportionate share of agreement production for any month but royalties are paid on the full volume of its proportionate share in accordance with the provisions of this section, no additional royalty will be owed for that lease for prior periods when the lessee subsequently takes more than its proportionate share to balance its account or when the lessee is paid a sum of money by the other agreement participants to balance its account.

(f) For production from Federal and Indian leases which are committed to federally-approved unitization or communitization agreements, upon request of a lessee MMS may establish the value of production pursuant to a method other than the method required by the regulations in this title if: (1) The proposed method for establishing value is consistent with the requirements of the applicable statutes, lease terms, and agreement terms; (2) persons with an interest in the agreement, including, to the extent practical, royalty interests, are given notice and an opportunity to comment on the proposed valuation method before it is authorized; and (3) to the extent practical, persons with an interest in a Federal or Indian

lease committed to the agreement, including royalty interests, must agree to use the proposed method for valuing production from the agreement for royalty purposes.

[53 FR 1217, Jan. 15, 1988]

#### **§ 202.101 Standards for reporting and paying royalties.**



Oil volumes are to be reported in barrels of clean oil of 42 standard U.S. gallons (231 cubic inches each) at 60 °F. When reporting oil volumes for royalty purposes, corrections must have been made for Basic Sediment and Water (BS&W) and other impurities. Reported American Petroleum Institute (API) oil gravities are to be those determined in accordance with standard industry procedures after correction to 60 °F.

[53 FR 1217, Jan. 15, 1988]

#### **Subpart D—Federal Gas**



**Source:** 53 FR 1271, Jan. 15, 1988, unless otherwise noted.

#### **§ 202.150 Royalty on gas.**



(a) Royalties due on gas production from leases subject to the requirements of this subpart, except helium produced from Federal leases, shall be at the rate established by the terms of the lease. Royalty shall be paid in value unless MMS requires payment in kind. When paid in value, the royalty due shall be the value, for royalty purposes, determined pursuant to 30 CFR part 206 of this title multiplied by the royalty rate in the lease.

(b)(1) All gas (except gas unavoidably lost or used on, or for the benefit of, the lease, including that gas used off-lease for the benefit of the lease when such off-lease use is permitted by the MMS or BLM, as appropriate) produced from a Federal lease to which this subpart applies is subject to royalty.

(2) When gas is used on, or for the benefit of, the lease at a production facility handling production from more than one lease with the approval of MMS or BLM, as appropriate, or at a production facility handling unitized or communitized production, only that proportionate share of each lease's production (actual or allocated) necessary to operate the production facility may be used royalty free.

(3) Where the terms of any lease are inconsistent with this subpart, the lease terms shall govern to the extent of that inconsistency.

(c) If BLM determines that gas was avoidably lost or wasted from an onshore lease, or that gas was drained from an onshore lease for which compensatory royalty is due, or if MMS determines that gas was avoidably lost or wasted from an OCS lease, then the value of that gas shall be determined in accordance with 30 CFR part 206.

(d) If a lessee receives insurance compensation for unavoidably lost gas, royalties are due on the amount of that compensation. This paragraph shall not apply to compensation through self-insurance.

(e)(1) In those instances where the lessee of any lease committed to a Federally approved unitization or communitization agreement does not actually take the proportionate share of the production attributable to its Federal lease under the terms of the agreement, the full share of production attributable to the lease under the terms of the agreement nonetheless is subject to the royalty payment and reporting requirements of this title. Except as provided in paragraph (e)(2) of this section, the value for royalty purposes of production attributable to unitized or communitized leases will be determined in accordance with 30 CFR part 206. In applying the requirements of 30 CFR part 206, the circumstances involved in the actual disposition of the portion of the production to which the lessee was entitled but did not take shall be considered as controlling in arriving at the value for royalty purposes of that portion, as if the person actually selling or disposing of the production were the lessee of the Federal lease.

(2) If a Federal lessee takes less than its proportionate share of agreement production, upon request of the lessee MMS may authorize a royalty valuation method different from that required by paragraph (e) (1) of this section, but consistent with the purpose of these regulations, for any volumes not taken by the lessee but for which royalties are due.

(3) For purposes of this subchapter, all persons actually taking volumes in excess of their proportionate share of production in any month under a unitization or communitization agreement shall be deemed to have taken ratably from all persons actually taking less than their proportionate share of the agreement production for that month.

(4) If a lessee takes less than its proportionate share of agreement production for any month but royalties are paid on the full volume of its proportionate share in accordance with the provisions of this section, no additional royalty will be owed for that lease for prior periods at the time the lessee subsequently takes more than its proportionate share to balance its account or when the lessee is paid a sum of money by the other agreement participants to balance its account.

(f) For production from Federal leases which are committed to federally-approved unitization or communitization agreements, upon request of a lessee MMS may establish the value of production pursuant to a method other than the method required by the regulations in this title if: (1) The proposed method for establishing value is consistent with the requirements of the applicable statutes, lease terms and agreement terms; (2) to the extent practical, persons with an interest in the agreement, including royalty interests, are given notice and an opportunity to comment on the proposed valuation method before it is authorized; and (3) to the extent practical, persons with an interest in a Federal lease committed to the agreement, including royalty interests, must agree to use the proposed method for valuing production from the agreement for royalty purposes.

[53 FR 1271, Jan. 15, 1988, as amended at 64 FR 43513, Aug. 10, 1999]

#### **§ 202.151 Royalty on processed gas.**



(a)(1) A royalty, as provided in the lease, shall be paid on the value of:

(i) Any condensate recovered downstream of the point of royalty settlement without resorting to processing; and

(ii) Residue gas and all gas plant products resulting from processing the gas produced from a lease subject to this subpart.

(2) MMS shall authorize a processing allowance for the reasonable, actual costs of processing the gas produced from Federal leases. Processing allowances shall be determined in accordance with 30 CFR part 206 subpart D for gas production from Federal leases and 30 CFR part 206 subpart E for gas production from Indian leases.

(b) A reasonable amount of residue gas shall be allowed royalty free for operation of the processing plant, but no allowance shall be made for boosting residue gas or other expenses incidental to marketing, except as provided in 30 CFR part 206. In those situations where a processing plant processes gas from more than one lease, only that proportionate share of each lease's residue gas necessary for the operation of the processing plant shall be allowed royalty free.

(c) No royalty is due on residue gas, or any gas plant product resulting from processing gas, which is reinjected into a reservoir within the same lease, unit area, or communitized area, when the reinjection is included in a plan of development or operations and the plan has received BLM or MMS approval for onshore or offshore operations, respectively, until such time as they are finally produced from the reservoir for sale or other disposition off-lease.

[53 FR 1217, Jan. 15, 1988, as amended at 61 FR 5490, Feb. 12, 1996; 64 FR 43513, Aug. 10, 1999]

#### **§ 202.152 Standards for reporting and paying royalties on gas.**



(a)(1) If you are responsible for reporting production or royalties, you must:

(i) Report gas volumes and British thermal unit (Btu) heating values, if applicable, under the same degree of water saturation;

(ii) Report gas volumes in units of 1,000 cubic feet (mcf); and

(iii) Report gas volumes and Btu heating value at a standard pressure base of 14.73 pounds per square inch absolute (psia) and a standard temperature base of 60 °F.

(2) The frequency and method of Btu measurement as set forth in the lessee's contract shall be used to determine Btu heating values for reporting purposes. However, the lessee shall measure the Btu value at least semiannually by recognized standard industry testing methods even if the lessee's contract provides for less frequent measurement.

(b)(1) Residue gas and gas plant product volumes shall be reported as specified in this paragraph.

(2) Carbon dioxide (CO<sub>2</sub>), nitrogen (N<sub>2</sub>), helium (He), residue gas, and any other gas marketed as a separate product shall be reported by using the same standards specified in paragraph (a) of this section.

(3) Natural gas liquids (NGL) volumes shall be reported in standard U.S. gallons (231 cubic inches) at 60 °F.

(4) Sulfur (S) volumes shall be reported in long tons (2,240 pounds).

[53 FR 1271, Jan. 15, 1988, as amended at 63 FR 26367, May 12, 1998]

#### **Subpart E—Solid Minerals, General [Reserved]**



[top](#)

#### **Subpart F—Coal**



[top](#)

#### **§ 202.250 Overriding royalty interest.**



[top](#)

The regulations governing overriding royalty interests, production payments, or similar interests created under Federal coal leases are in 43 CFR group 3400.

[54 FR 1522, Jan. 13, 1989]

#### **Subpart G—Other Solid Minerals [Reserved]**



[top](#)

#### **Subpart H—Geothermal Resources**



[top](#)

**Source:** 56 FR 57275, Nov. 8, 1991, unless otherwise noted.

#### **§ 202.350 Scope and definitions.**



[top](#)

(a) This subpart is applicable to all geothermal resources produced from Federal geothermal leases

issued pursuant to the Geothermal Steam Act of 1970, as amended (30 U.S.C. 1001 *et seq.*).

(b) The definitions in 30 CFR 206.351 are applicable to this subpart.

#### **§ 202.351 Royalties on geothermal resources.**



(a)(1) Royalties on geothermal resources, including byproducts, or on electricity produced using geothermal resources, will be at the royalty rate(s) specified in the lease, unless the Secretary of the Interior temporarily waives, suspends, or reduces that rate(s). Royalties are determined under 30 CFR part 206, subpart H.

(2) Fees in lieu of royalties on geothermal resources are prescribed in 30 CFR part 206, subpart H.

(3) Except for the amount credited against royalties for in-kind deliveries of electricity to a State or county under §218.306, you must pay royalties and direct use fees in money.

(b)(1) Except as specified in paragraph (b)(2) of this section, royalties or fees are due on—

(i) All geothermal resources produced from a lease and that are sold or used by the lessee or are reasonably susceptible to sale or use by the lessee, or

(ii) All proceeds derived from the sale of electricity produced using geothermal resources produced from a lease.

(2) For purposes of this subparagraph, the terms "Class I lease," "Class II lease," and "Class III lease" have the same meanings prescribed in 30 CFR 206.351.

(i) For Class I leases, MMS will allow free of royalty—

(A) Geothermal resources that are unavoidably lost or reinjected before use on or off the lease, as determined by the Bureau of Land Management (BLM), or that are reasonably necessary to generate plant parasitic electricity or electricity for Federal lease operations; and

(B) A reasonable amount of commercially demineralized water necessary for power plant operations or otherwise used on or for the benefit of the lease.

(ii) For Class II and Class III leases where the lessee uses geothermal resources for commercial production or generation of electricity, or where geothermal resources are sold at arm's length for the commercial production or generation of electricity, MMS will allow free of royalty or direct use fees geothermal resources that are:

(A) Unavoidably lost or reinjected before use on or off the lease, as determined by BLM;

(B) Reasonably necessary for the lessee to generate plant parasitic electricity or electricity for Federal lease operations, as approved by BLM; or

(C) Otherwise used for Federal lease operations related to commercial production or generation of electricity, as approved by BLM.

(iii) For Class II and Class III leases where the lessee uses the geothermal resources for a direct use or in a direct use facility, as defined in 30 CFR 206.351, resources that are used to generate electricity for Federal lease operations or that are otherwise used for Federal lease operations are subject to direct use fees, except for geothermal resources that are unavoidably lost or reinjected before use on or off the lease, as determined by BLM.

(3) Royalties on byproducts are due at the time the recovered byproduct is used, sold, or otherwise finally disposed of. Byproducts produced and added to stockpiles or inventory do not require payment of royalty until the byproducts are sold, utilized, or otherwise finally disposed of. The MMS may ask BLM to increase the lease bond to protect the lessor's interest when BLM determines that stockpiles or inventories become excessive.

(c) If BLM determines that geothermal resources (including byproducts) were avoidably lost or wasted

from the lease, or that geothermal resources (including byproducts) were drained from the lease for which compensatory royalty (or compensatory fees in lieu of compensatory royalty) are due, the value of those geothermal resources, or the royalty or fees owed, will be determined under 30 CFR part 206, subpart H.

(d) If a lessee receives insurance or other compensation for unavoidably lost geothermal resources (including byproducts), royalties at the rates specified in the lease (or fees in lieu of royalties) are due on the amount of, or as a result of, that compensation. This paragraph will not apply to compensation through self-insurance.

[72 FR 24458, May 2, 2007]

#### **§ 202.352 Minimum royalty.**



[top](#)

In no event shall the lessee's annual royalty payments for any producing lease be less than the minimum royalty established by the lease.

#### **§ 202.353 Measurement standards for reporting and paying royalties and direct use fees.**



[top](#)

(a) For geothermal resources used to generate electricity, you must report the quantity on which royalty is due on Form MMS-2014 (Report of Sales and Royalty Remittance) as follows:

(1) For geothermal resources for which royalty is calculated under §206.352(a), you must report quantities in:

(i) Thousands of pounds to the nearest whole thousand pounds if the contract for the geothermal resources specifies delivery in terms of weight; or

(ii) Millions of Btu to the nearest whole million Btu if the sales contract for the geothermal resources specifies delivery in terms of heat or thermal energy.

(2) For geothermal resources for which royalty is calculated under §206.352(b), you must report the quantities in kilowatt-hours to the nearest whole kilowatt-hour.

(b) For geothermal resources used in direct use processes, you must report the quantity on which a royalty or direct use fee is due on Form MMS-2014 in:

(1) Millions of Btu to the nearest whole million Btu if valuation is in terms of heat or thermal energy used or displaced;

(2) Millions of gallons to the nearest million gallons of geothermal fluid produced if valuation or fee calculation is in terms of volume;

(3) Millions of pounds to the nearest million pounds of geothermal fluid produced if valuation or fee calculation is in terms of mass; or

(4) Any other measurement unit MMS approves for valuation and reporting purposes.

(c) For byproducts, you must report the quantity on which royalty is due on Form MMS-2014 consistent with MMS-established reporting standards.

(d) For commercially demineralized water, you must report the quantity on which royalty is due on Form MMS-2014 in hundreds of gallons to the nearest hundred gallons.

(e) You need not report the quality of geothermal resources, including byproducts, to MMS. However, you must maintain quality measurements for audit purposes. Quality measurements include, but are not limited to:

- (1) Temperatures and chemical analyses for fluid geothermal resources; and
- (2) Chemical analyses, weight percent, or other purity measurements for byproducts.

[72 FR 24458, May 2, 2007]

#### **Subpart I—OCS Sulfur [Reserved]**



[top](#)

#### **Subpart J—Gas Production From Indian Leases**



[top](#)

**Source:** 64 FR 43514, Aug. 10, 1999, unless otherwise noted.

#### **§ 202.550 How do I determine the royalty due on gas production?**



[top](#)

If you produce gas from an Indian lease subject to this subpart, you must determine and pay royalties on gas production as specified in this section.

- (a) *Royalty rate.* You must calculate your royalty using the royalty rate in the lease.
- (b) *Payment in value or in kind.* You must pay royalty in value unless:
  - (1) The Tribal lessor requires payment in kind; or
  - (2) You have a lease on allotted lands and MMS requires payment in kind.
- (c) *Royalty calculation.* You must use the following calculations to determine royalty due on the production from or attributable to your lease.
  - (1) When paid in value, the royalty due is the unit value of production for royalty purposes, determined under 30 CFR part 206, multiplied by the volume of production multiplied by the royalty rate in the lease.
  - (2) When paid in kind, the royalty due is the volume of production multiplied by the royalty rate.
- (d) *Reduced royalty rate.* The Indian lessor and the Secretary may approve a request for a royalty rate reduction. In your request you must demonstrate economic hardship.
- (e) *Reporting and paying.* You must report and pay royalties as provided in part 218 of this title.

#### **§ 202.551 How do I determine the volume of production for which I must pay royalty if my lease is not in an approved Federal unit or communitization agreement (AFA)?**



[top](#)

- (a) You are liable for royalty on your entitled share of gas production from your Indian lease, except as provided in §§202.555, 202.556, and 202.557.
- (b) You and all other persons paying royalties on the lease must report and pay royalties based on your takes. If another person takes some of your entitled share but does not pay the royalties owed, you are liable for those royalties.
- (c) You and all other persons paying royalties on the lease may ask MMS for permission to report and pay royalties based on your entitlements. In that event, MMS will provide valuation instructions consistent with this part and part 206 of this title.

**§ 202.552 How do I determine how much royalty I must pay if my lease is in an approved Federal unit or communitization agreement (AFA)?**



You must pay royalties each month on production allocated to your lease under the terms of an AFA. To determine the volume and the value of your production, you must follow these three steps:

(a) You must determine the volume of your entitled share of production allocated to your lease under the terms of an AFA. This may include production from more than one AFA.

(b) You must value the production you take using 30 CFR part 206. If you take more than your entitled share of production, see §202.553 for information on how to value this production. If you take less than your entitled share of production, see §202.554 for information on how to value production you are entitled to but do not take.

**§ 202.553 How do I value my production if I take more than my entitled share?**



If you take more than your entitled share of production from a lease in an AFA for any month, you must determine the weighted-average value of all of the production that you take using the procedures in 30 CFR part 206, and use that value for your entitled share of production.

**§ 202.554 How do I value my production that I do not take if I take less than my entitled share?**



If you take none or only part of your entitled production from a lease in an AFA for any month, use this section to value the production that you are entitled to but do not take.

(a) If you take a significant volume of production from your lease during the month, you must determine the weighted average value of the production that you take using 30 CFR part 206, and use that value for the production that you do not take.

(b) If you do not take a significant volume of production from your lease during the month, you must use paragraph (c) or (d) of this section, whichever applies.

(c) In a month where you do not take production or take an insignificant volume, and if you would have used §206.172(b) to value the production if you had taken it, you must determine the value of production not taken for that month under §206.172(b) as if you had taken it.

(d) If you take none of your entitled share of production from a lease in an AFA, and if that production cannot be valued under §206.172(b), then you must determine the value of the production that you do not take using the first of the following methods that applies:

(1) The weighted average of the value of your production (under 30 CFR part 206) in that month from other leases in the same AFA.

(2) The weighted average of the value of your production (under 30 CFR part 206) in that month from other leases in the same field or area.

(3) The weighted average of the value of your production (under 30 CFR part 206) during the previous month for production from leases in the same AFA.

(4) The weighted average of the value of your production (under 30 CFR part 206) during the previous month for production from other leases in the same field or area.

(5) The latest major portion value that you received from MMS calculated under 30 CFR 206.174 for the same MMS-designated area.

(e) You may take less than your entitled share of AFA production for any month, but pay royalties on the full volume of your entitled share under this section. If you do, you will owe no additional royalty for that lease for that month when you later take more than your entitled share to balance your account. The provisions of this paragraph (e) also apply when the other AFA participants pay you money to balance your account.

**§ 202.555 What portion of the gas that I produce is subject to royalty?**



[top](#)

(a) All gas produced from or allocated to your Indian lease is subject to royalty except the following:

(1) Gas that is unavoidably lost.

(2) Gas that is used on, or for the benefit of, the lease.

(3) Gas that is used off-lease for the benefit of the lease when the Bureau of Land Management (BLM) approves such off-lease use.

(4) Gas used as plant fuel as provided in 30 CFR 206.179(e).

(b) You may use royalty-free only that proportionate share of each lease's production (actual or allocated) necessary to operate the production facility when you use gas for one of the following purposes:

(1) On, or for the benefit of, the lease at a production facility handling production from more than one lease with BLM's approval.

(2) At a production facility handling unitized or communitized production.

(c) If the terms of your lease are inconsistent with this subpart, your lease terms will govern to the extent of that inconsistency.

**§ 202.556 How do I determine the value of avoidably lost, wasted, or drained gas?**



[top](#)

If BLM determines that a volume of gas was avoidably lost or wasted, or a volume of gas was drained from your Indian lease for which compensatory royalty is due, then you must determine the value of that volume of gas under 30 CFR part 206.

**§ 202.557 Must I pay royalty on insurance compensation for unavoidably lost gas?**



[top](#)

If you receive insurance compensation for unavoidably lost gas, you must pay royalties on the amount of that compensation. This paragraph does not apply to compensation through self-insurance.

**§ 202.558 What standards do I use to report and pay royalties on gas?**



[top](#)

(a) You must report gas volumes as follows:

(1) Report gas volumes and Btu heating values, if applicable, under the same degree of water saturation. Report gas volumes and Btu heating value at a standard pressure base of 14.73 psia and a standard temperature of 60 degrees Fahrenheit. Report gas volumes in units of 1,000 cubic feet (Mcf).

(2) You must use the frequency and method of Btu measurement stated in your contract to determine Btu heating values for reporting purposes. However, you must measure the Btu value at least semi-annually by recognized standard industry testing methods even if your contract provides for less

frequent measurement.

(b) You must report residue gas and gas plant product volumes as follows:

- (1) Report carbon dioxide (CO<sub>2</sub>), nitrogen (N<sub>2</sub>), helium (He), residue gas, and any gas marketed as a separate product by using the same standards specified in paragraph (a) of this section.
- (2) Report natural gas liquid (NGL) volumes in standard U.S. gallons (231 cubic inches) at 60 degrees F.
- (3) Report sulfur (S) volumes in long tons (2,240 pounds).

[Browse Previous](#) | [Browse Next](#)

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### Title 30: Mineral Resources

[Browse Previous](#) | [Browse Next](#)

#### PART 206—PRODUCT VALUATION

##### Section Contents

##### Subpart A—General Provisions

[§ 206.10 Information collection.](#)

##### Subpart B—Indian Oil

[§ 206.50 What is the purpose of this subpart?](#)

[§ 206.51 What definitions apply to this subpart?](#)

[§ 206.52 How do I calculate royalty value for oil that I or my affiliate sell\(s\) or exchange\(s\) under an arm's-length contract?](#)

[§ 206.53 How do I determine value for oil that I or my affiliate do\(es\) not sell under an arm's-length contract?](#)

[§ 206.54 How do I fulfill the lease provision regarding valuing production on the basis of the major portion of like-quality oil?](#)

[§ 206.55 What are my responsibilities to place production into marketable condition and to market the production?](#)

[§ 206.56 Transportation allowances—general.](#)

[§ 206.57 Determination of transportation allowances.](#)

[§ 206.58 What must I do if MMS finds that I have not properly determined value?](#)

[§ 206.59 May I ask MMS for valuation guidance?](#)

[§ 206.60 What are the quantity and quality bases for royalty settlement?](#)

[§ 206.61 What records must I keep and produce?](#)

[§ 206.62 Does MMS protect information I provide?](#)

##### Subpart C—Federal Oil

[§ 206.100 What is the purpose of this subpart?](#)

[§ 206.101 What definitions apply to this subpart?](#)

[§ 206.102 How do I calculate royalty value for oil that I or my affiliate sell\(s\) under an arm's-length contract?](#)

[§ 206.103 How do I value oil that is not sold under an arm's-length contract?](#)

[§ 206.104 What publications are acceptable to MMS?](#)

[§ 206.105 What records must I keep to support my calculations of value under this subpart?](#)

[§ 206.106 What are my responsibilities to place production into marketable condition and to market production?](#)

[§ 206.107 How do I request a value determination?](#)

[§ 206.108 Does MMS protect information I provide?](#)

[§ 206.109 When may I take a transportation allowance in determining value?](#)

[§ 206.110 How do I determine a transportation allowance under an arm's-length transportation contract?](#)

[§ 206.111 How do I determine a transportation allowance if I do not have an arm's-length transportation contract or arm's-length tariff?](#)

[§ 206.112 What adjustments and transportation allowances apply when I value oil](#)

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16

- production from my lease using NYMEX prices or ANS spot prices?  
§ 206.113 How will MMS identify market centers?  
§ 206.114 What are my reporting requirements under an arm's-length transportation contract?  
§ 206.115 What are my reporting requirements under a non-arm's-length transportation arrangement?  
§ 206.116 What interest applies if I improperly report a transportation allowance?  
§ 206.117 What reporting adjustments must I make for transportation allowances?  
§ 206.119 How are royalty quantity and quality determined?  
§ 206.120 How are operating allowances determined?

#### **Subpart D—Federal Gas**

- § 206.150 Purpose and scope.  
§ 206.151 Definitions.  
§ 206.152 Valuation standards—unprocessed gas.  
§ 206.153 Valuation standards—processed gas.  
§ 206.154 Determination of quantities and qualities for computing royalties.  
§ 206.155 Accounting for comparison.  
§ 206.156 Transportation allowances—general.  
§ 206.157 Determination of transportation allowances.  
§ 206.158 Processing allowances—general.  
§ 206.159 Determination of processing allowances.  
§ 206.160 Operating allowances.

#### **Subpart E—Indian Gas**

- § 206.170 What does this subpart contain?  
§ 206.171 What definitions apply to this subpart?  
§ 206.172 How do I value gas produced from leases in an index zone?  
§ 206.173 How do I calculate the alternative methodology for dual accounting?  
§ 206.174 How do I value gas production when an index-based method cannot be used?  
§ 206.175 How do I determine quantities and qualities of production for computing royalties?  
§ 206.176 How do I perform accounting for comparison?

#### **Transportation Allowances**

- § 206.177 What general requirements regarding transportation allowances apply to me?  
§ 206.178 How do I determine a transportation allowance?

#### **Processing Allowances**

- § 206.179 What general requirements regarding processing allowances apply to me?  
§ 206.180 How do I determine an actual processing allowance?  
§ 206.181 How do I establish processing costs for dual accounting purposes when I do not process the gas?

#### **Subpart F—Federal Coal**

- § 206.250 Purpose and scope.  
§ 206.251 Definitions.  
§ 206.252 Information collection.  
§ 206.253 Coal subject to royalties—general provisions.  
§ 206.254 Quality and quantity measurement standards for reporting and paying royalties.  
§ 206.255 Point of royalty determination.  
§ 206.256 Valuation standards for cents-per-ton leases.  
§ 206.257 Valuation standards for ad valorem leases.  
§ 206.258 Washing allowances—general.  
§ 206.259 Determination of washing allowances.  
§ 206.260 Allocation of washed coal.  
§ 206.261 Transportation allowances—general.  
§ 206.262 Determination of transportation allowances.  
§ 206.263 [Reserved]  
§ 206.264 In-situ and surface gasification and liquefaction operations.  
§ 206.265 Value enhancement of marketable coal.

#### **Subpart G—Other Solid Minerals**

§ 206.301 Value basis for royalty computation.

#### **Subpart H—Geothermal Resources**

§ 206.350 What is the purpose of this subpart?

§ 206.351 What definitions apply to this subpart?

§ 206.352 How do I calculate the royalty due on geothermal resources used for commercial production or generation of electricity?

§ 206.353 How do I determine transmission deductions?

§ 206.354 How do I determine generating deductions?

§ 206.355 How do I calculate royalty due on geothermal resources I sell at arm's length to a purchaser for direct use?

§ 206.356 How do I calculate royalty or fees due on geothermal resources I use for direct use purposes?

§ 206.357 How do I calculate royalty due on byproducts?

§ 206.358 What are byproduct transportation allowances?

§ 206.359 How do I determine byproduct transportation allowances?

§ 206.360 What records must I keep to support my calculations of royalty or fees under this subpart?

§ 206.361 How will MMS determine whether my royalty or direct use fee payments are correct?

§ 206.362 What are my responsibilities to place production into marketable condition and to market production?

§ 206.363 When is an MMS audit, review, reconciliation, monitoring, or other like process considered final?

§ 206.364 How do I request a value or gross proceeds determination?

§ 206.365 Does MMS protect information I provide?

§ 206.366 What is the nominal fee that a State, tribal, or local government lessee must pay for the use of geothermal resources?

#### **Subpart I—OCS Sulfur [Reserved]**

#### **Subpart J—Indian Coal**

§ 206.450 Purpose and scope.

§ 206.451 Definitions.

§ 206.452 Coal subject to royalties—general provisions.

§ 206.453 Quality and quantity measurement standards for reporting and paying royalties.

§ 206.454 Point of royalty determination.

§ 206.455 Valuation standards for cents-per-ton leases.

§ 206.456 Valuation standards for ad valorem leases.

§ 206.457 Washing allowances—general.

§ 206.458 Determination of washing allowances.

§ 206.459 Allocation of washed coal.

§ 206.460 Transportation allowances—general.

§ 206.461 Determination of transportation allowances.

§ 206.462 [Reserved]

§ 206.463 In-situ and surface gasification and liquefaction operations.

§ 206.464 Value enhancement of marketable coal.

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**Authority:** 5 U.S.C. 301 *et seq.*; 25 U.S.C. 396 *et seq.*, 396a *et seq.*, 2101 *et seq.*; 30 U.S.C. 181 *et seq.*, 351 *et seq.*, 1001 *et seq.*, 1701 *et seq.*; 31 U.S.C. 9701.; 43 U.S.C. 1301 *et seq.*, 1331 *et seq.*, and 1801 *et seq.*

**Editorial Note:** Nomenclature changes to part 206 appear at 67 FR 19111, Apr. 18, 2002.

#### **Subpart A—General Provisions**



top

**§ 206.10 Information collection.**



[top](#)

The information collection requirements contained in this part have been approved by the Office of Management and Budget (OMB) under 44 U.S.C. 3501 *et seq.* The forms, filing date, and approved OMB clearance numbers are identified in 30 CFR 210.10.

[57 FR 41863, Sept. 14, 1992]

## Subpart B—Indian Oil



[top](#)

**Source:** 61 FR 5455, Feb. 12, 1996, unless otherwise noted.

### § 206.50 What is the purpose of this subpart?



[top](#)

(a) This subpart applies to all oil produced from Indian (tribal and allotted) oil and gas leases (except leases on the Osage Indian Reservation, Osage County, Oklahoma). This subpart does not apply to Federal leases, including Federal leases for which revenues are shared with Alaska Native Corporations. This subpart:

- (1) Establishes the value of production for royalty purposes consistent with the Indian mineral leasing laws, other applicable laws, and lease terms;
  - (2) Explains how you as a lessee must calculate the value of production for royalty purposes consistent with applicable statutes and lease terms; and
  - (3) Is intended to ensure that the United States discharges its trust responsibilities for administering Indian oil and gas leases under the governing Indian mineral leasing laws, treaties, and lease terms.
- (b) If the regulations in this subpart are inconsistent with a Federal statute, a settlement agreement or written agreement as these terms are defined in this paragraph, or an express provision of an oil and gas lease subject to this subpart, then the statute, settlement agreement, written agreement, or lease provision will govern to the extent of the inconsistency. For purposes of this paragraph:

- (1) *Settlement agreement* means a settlement agreement that is between the United States and a lessee, or between an individual Indian mineral owner and a lessee and is approved by the United States, resulting from administrative or judicial litigation; and
  - (2) *Written agreement* means a written agreement between the lessee and the MMS Director (and approved by the tribal lessor for tribal leases) establishing a method to determine the value of production from any lease that MMS expects at least would approximate the value established under this subpart.
- (c) The MMS or Indian tribes may audit, or perform other compliance reviews, and require a lessee to adjust royalty payments and reports.

[72 FR 71241, Dec. 17, 2007]

### § 206.51 What definitions apply to this subpart?



[top](#)

For purposes of this subpart:

*Affiliate* means a person who controls, is controlled by, or is under common control with another person.

- (1) Ownership or common ownership of more than 50 percent of the voting securities, or instruments of ownership, or other forms of ownership, of another person constitutes control. Ownership of less than 10 percent constitutes a presumption of noncontrol that MMS may rebut.

(2) If there is ownership or common ownership of 10 through 50 percent of the voting securities or instruments of ownership, or other forms of ownership, of another person, MMS will consider the following factors in determining whether there is control in a particular case:

- (i) The extent to which there are common officers or directors;
  - (ii) With respect to the voting securities, or instruments of ownership, or other forms of ownership:
    - (A) The percentage of ownership or common ownership;
    - (B) The relative percentage of ownership or common ownership compared to the percentage(s) of ownership by other persons;
    - (C) Whether a person is the greatest single owner; and
    - (D) Whether there is an opposing voting bloc of greater ownership;
  - (iii) Operation of a lease, plant, or other facility;
  - (iv) The extent of participation by other owners in operations and day-to-day management of a lease, plant, or other facility; and
  - (v) Other evidence of power to exercise control over or common control with another person.
- (3) Regardless of any percentage of ownership or common ownership, relatives, either by blood or marriage, are affiliates.

*Area* means a geographic region at least as large as the defined limits of an oil and/or gas field in which oil and/or gas lease products have similar quality, economic, and legal characteristics.

*Arm's-length contract* means a contract or agreement between independent persons who are not affiliates and who have opposing economic interests regarding that contract. To be considered arm's length for any production month, a contract must satisfy this definition for that month, as well as when the contract was executed.

*Audit* means a review, conducted in accordance with generally accepted accounting and auditing standards, of royalty payment compliance activities of lessees or other interest holders who pay royalties, rents, or bonuses on Indian leases.

*BLM* means the Bureau of Land Management of the Department of the Interior.

*Condensate* means liquid hydrocarbons (generally exceeding 40 degrees of API gravity) recovered at the surface without resorting to processing. Condensate is the mixture of liquid hydrocarbons that results from condensation of petroleum hydrocarbons existing initially in a gaseous phase in an underground reservoir.

*Contract* means any oral or written agreement, including amendments or revisions thereto, between two or more persons and enforceable by law that with due consideration creates an obligation.

*Exchange agreement* means an agreement where one person agrees to deliver oil to another person at a specified location in exchange for oil deliveries at another location, and other consideration. Exchange agreements:

- (1) May or may not specify prices for the oil involved;
- (2) Frequently specify dollar amounts reflecting location, quality, or other differentials;
- (3) Include buy/sell agreements, which specify prices to be paid at each exchange point and may appear to be two separate sales within the same agreement, or in separate agreements; and
- (4) May include, but are not limited to, exchanges of produced oil for specific types of oil (e.g., WTI); exchanges of produced oil for other oil at other locations (location trades); exchanges of produced oil for other grades of oil (grade trades); and multi-party exchanges.

*Field* means a geographic region situated over one or more subsurface oil and gas reservoirs encompassing at least the outermost boundaries of all oil and gas accumulations known to be within those reservoirs vertically projected to the land surface. Onshore fields usually are given names, and their official boundaries are often designated by oil and gas regulatory agencies in the respective states in which the fields are located.

*Gathering* means the movement of lease production to a central accumulation or treatment point on the lease, unit, or communitized area, or to a central accumulation or treatment point off the lease, unit, or communitized area as approved by BLM operations personnel.

*Gross proceeds* means the total monies and other consideration accruing for the disposition of oil produced. Gross proceeds also include, but are not limited to, the following examples:

- (1) Payments for services, such as dehydration, marketing, measurement, or gathering that the lessee must perform at no cost to the lessor in order to put the production into marketable condition;
- (2) The value of services to put the production into marketable condition, such as salt water disposal, that the lessee normally performs but that the buyer performs on the lessee's behalf;
- (3) Reimbursements for harboring or terminaling fees;
- (4) Tax reimbursements, even though the Indian royalty interest may be exempt from taxation;
- (5) Payments made to reduce or buy down the purchase price of oil to be produced in later periods, by allocating those payments over the production whose price the payment reduces and including the allocated amounts as proceeds for the production as it occurs; and
- (6) Monies and all other consideration to which a seller is contractually or legally entitled, but does not seek to collect through reasonable efforts.

*Indian tribe* means any Indian tribe, band, nation, pueblo, community, rancheria, colony, or other group of Indians for which any minerals or interest in minerals is held in trust by the United States or that is subject to Federal restriction against alienation.

*Individual Indian mineral owner* means any Indian for whom minerals or an interest in minerals is held in trust by the United States or who holds title subject to Federal restriction against alienation.

*Lease* means any contract, profit-share arrangement, joint venture, or other agreement issued or approved by the United States under an Indian mineral leasing law that authorizes exploration for, development or extraction of, or removal of lease products. Depending on the context, lease may also refer to the land area covered by that authorization.

*Lease products* means any leased minerals attributable to, originating from, or allocated to Indian leases.

*Lessee* means any person to whom the United States, a tribe, or individual Indian mineral owner issues a lease, and any person who has been assigned an obligation to make royalty or other payments required by the lease. Lessee includes:

- (1) Any person who has an interest in a lease (including operating rights owners); and
- (2) An operator, purchaser, or other person with no lease interest who makes royalty payments to MMS or the lessor on the lessee's behalf

*Lessor* means an Indian tribe or individual Indian mineral owner who has entered into a lease.

*Like-quality oil* means oil that has similar chemical and physical characteristics.

*Location differential* means an amount paid or received (whether in money or in barrels of oil) under an exchange agreement that results from differences in location between oil delivered in exchange and oil received in the exchange. A location differential may represent all or part of the difference between the price received for oil delivered and the price paid for oil received under a buy/sell exchange agreement.

*Marketable condition* means lease products that are sufficiently free from impurities and otherwise in a condition that they will be accepted by a purchaser under a sales contract typical for the field or area.

*MMS* means the Minerals Management Service of the Department of the Interior.

*Net* means to reduce the reported sales value to account for transportation instead of reporting a transportation allowance as a separate entry on Form MMS-2014.

*NYMEX price* means the average of the New York Mercantile Exchange (NYMEX) settlement prices for light sweet oil delivered at Cushing, Oklahoma, calculated as follows:

- (1) Sum the prices published for each day during the calendar month of production (excluding weekends and holidays) for oil to be delivered in the nearest month of delivery for which NYMEX futures prices are published corresponding to each such day; and
- (2) Divide the sum by the number of days on which those prices are published (excluding weekends and holidays).

*Oil* means a mixture of hydrocarbons that existed in the liquid phase in natural underground reservoirs and remains liquid at atmospheric pressure after passing through surface separating facilities and is marketed or used as such. Condensate recovered in lease separators or field facilities is considered to be oil.

*Operating rights owner*, also known as a working interest owner, means any person who owns operating rights in a lease subject to this subpart. A record title owner is the owner of operating rights under a lease until the operating rights have been transferred from record title (see Bureau of Land Management regulations at 43 CFR 3100.0-5(d)).

*Person* means any individual, firm, corporation, association, partnership, consortium, or joint venture (when established as a separate entity).

*Processing* means 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.

*Quality differential* means an amount paid or received under an exchange agreement (whether in money or in barrels of oil) that results from differences in API gravity, sulfur content, viscosity, metals content, and other quality factors between oil delivered and oil received in the exchange. A quality differential may represent all or part of the difference between the price received for oil delivered and the price paid for oil received under a buy/sell agreement.

*Sale* means a contract between two persons where:

- (1) The seller unconditionally transfers title to the oil to the buyer and does not retain any related rights such as the right to buy back similar quantities of oil from the buyer elsewhere;
- (2) The buyer pays money or other consideration for the oil; and
- (3) The parties' intent is for a sale of the oil to occur.

*Sales type code* means the contract type or general disposition (e.g., arm's-length or non-arm's-length) of production from the lease. The sales type code applies to the sales contract, or other disposition, and not to the arm's-length or non-arm's-length nature of a transportation allowance.

*Transportation allowance* means a deduction in determining royalty value for the reasonable, actual costs of moving oil to a point of sale or delivery off the lease, unit area, or communitized area. The transportation allowance does not include gathering costs.

*WTI* means West Texas Intermediate.

*You* means a lessee, operator, or other person who pays royalties under this subpart.

[72 FR 71241, Dec. 17, 2007, as amended at 73 FR 15890, Mar. 26, 2008]

**§ 206.52 How do I calculate royalty value for oil that I or my affiliate sell(s) or exchange(s) under an arm's-length contract?**



[top](#)

(a) The value of oil under this section is the gross proceeds accruing to the seller under the arm's-length contract, less applicable allowances determined under §§206.56 and 206.57. If the arm's-length sales contract does not reflect the total consideration actually transferred either directly or indirectly from the buyer to the seller, you must value the oil sold as the total consideration accruing to the seller. Use this section to value oil that:

(1) You sell under an arm's-length sales contract; or

(2) You sell or transfer to your affiliate or another person under a non-arm's-length contract and that affiliate or person, or another affiliate of either of them, then sells the oil under an arm's-length contract.

(b) If you have multiple arm's-length contracts to sell oil produced from a lease that is valued under paragraph (a) of this section, the value of the oil is the volume-weighted average of the total consideration established under this section for all contracts for the sale of oil produced from that lease.

(c) If MMS determines that the value under paragraph (a) of this section does not reflect the reasonable value of the production due to either:

(1) Misconduct by or between the parties to the arm's-length contract; or

(2) Breach of your duty to market the oil for the mutual benefit of yourself and the lessor, MMS will establish a value based on other relevant matters.

(i) The MMS will not use this provision to simply substitute its judgment of the market value of the oil for the proceeds received by the seller under an arm's-length sales contract.

(ii) The fact that the price received by the seller under an arm's-length contract is less than other measures of market price is insufficient to establish breach of the duty to market unless MMS finds additional evidence that the seller acted unreasonably or in bad faith in the sale of oil produced from the lease.

(d) You must base value on the highest price that the seller can receive through legally enforceable claims under the oil sales contract. If the seller fails to take proper or timely action to receive prices or benefits to which it is entitled, you must base value on that obtainable price or benefit.

(1) In some cases the seller may apply timely for a price increase or benefit allowed under the oil sales contract, but the purchaser refuses the seller's request. If this occurs, and the seller takes reasonable documented measures to force purchaser compliance, you will owe no additional royalties unless or until the seller receives monies or consideration resulting from the price increase or additional benefits. This paragraph (d)(1) does not permit you to avoid your royalty payment obligation if a purchaser fails to pay, pays only in part, or pays late.

(2) Any contract revisions or amendments that reduce prices or benefits to which the seller is entitled must be in writing and signed by all parties to the arm's-length contract.

(e) If you or your affiliate enter(s) into an arm's-length exchange agreement, or multiple sequential arm's-length exchange agreements, then you must value your oil under this paragraph.

(1) If you or your affiliate exchange(s) oil at arm's length for WTI or equivalent oil at Cushing, Oklahoma, you must value the oil using the NYMEX price, adjusted for applicable location and quality differentials under paragraph (e)(3) of this section and any transportation costs under paragraph (e)(4) of this section and §§206.56 and 206.57.

(2) If you do not exchange oil for WTI or equivalent oil at Cushing, but exchange it at arm's length for oil at another location and following the arm's-length exchange(s) you or your affiliate sell(s) the oil received in the exchange(s) under an arm's-length contract, then you must use the gross proceeds under your or your affiliate's arm's-length sales contract after the exchange(s) occur(s), adjusted for applicable location and quality differentials under paragraph (e)(3) of this section and any transportation costs under paragraph (e)(4) of this section and §§206.56 and 206.57.

(3) You must adjust your gross proceeds for any location or quality differential, or other adjustments, you received or paid under the arm's-length exchange agreement(s). If MMS determines that any exchange agreement does not reflect reasonable location or quality differentials, MMS may adjust the differentials you used based on relevant information. You may not otherwise use the price or differential specified in

an arm's-length exchange agreement to value your production.

(4) If you value oil under this paragraph, MMS will allow a deduction, under §§206.56 and 206.57, for the reasonable, actual costs to transport the oil:

(i) From the lease to a point where oil is given in exchange; and

(ii) If oil is not exchanged to Cushing, Oklahoma, from the point where oil is received in exchange to the point where the oil received in exchange is sold.

(5) If you or your affiliate exchange(s) your oil at arm's length, and neither paragraph (e)(1) nor (e)(2) of this section applies, MMS will establish a value for the oil based on relevant matters. After MMS establishes the value, you must report and pay royalties and any late payment interest owed based on that value.

(f) You may not deduct any costs of gathering as part of a transportation deduction or allowance.

(g) You must also comply with §206.54.

[72 FR 71241, Dec. 17, 2007]

### § 206.53 How do I determine value for oil that I or my affiliate do(es) not sell under an arm's-length contract?



[top](#)

(a) The unit value of your oil not sold under an arm's-length contract is the volume-weighted average of the gross proceeds paid or received by you or your affiliate, including your refining affiliate, for purchases or sales under arm's-length contracts.

(1) When calculating that unit value, use only purchases or sales of other like-quality oil produced from the field (or the same area if you do not have sufficient arm's-length purchases or sales of oil produced from the field) during the production month.

(2) You may adjust the gross proceeds determined under paragraph (a) of this section for transportation costs under paragraph (c) of this section and §§206.56 and 206.57 before including those proceeds in the volume-weighted average calculation.

(3) If you have purchases away from the field(s) and cannot calculate a price in the field because you cannot determine the seller's cost of transportation that would be allowed under paragraph (c) of this section and §§206.56 and 206.57, you must not include those purchases in your weighted-average calculation.

(b) Before calculating the volume-weighted average, you must normalize the quality of the oil in your or your affiliate's arm's-length purchases or sales to the same gravity as that of the oil produced from the lease. Use applicable gravity adjustment tables for the field (or the same general area for like-quality oil if you do not have gravity adjustment tables for the specific field) to normalize for gravity.

*Example to paragraph(b):* 1. Assume that a lessee, who owns a refinery and refines the oil produced from the lease at that refinery, purchases like-quality oil from other producers in the same field at arm's length for use as feedstock in its refinery. Further assume that the oil produced from the lease that is being valued under this section is Wyoming general sour with an API gravity of 23.5°. Assume that the refinery purchases at arm's length oil (all of which must be Wyoming general sour) in the following volumes of the API gravities stated at the prices and locations indicated:

10,000 bbl	24.5°	\$34.70/bbl	Purchased in the field.
8,000 bbl	24.0°	34.00/bbl	Purchased at the refinery after the third-party producer transported it to the refinery, and the lessee does not know the transportation costs.
9,000 bbl	23.0°	33.25/bbl	Purchased in the field.

4,000 bbl	22.0°	33.00/bbl	Purchased in the field.
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2. Because the lessee does not know the costs that the seller of the 8,000 bbl incurred to transport that volume to the refinery, that volume will not be included in the volume-weighted average price calculation. Further assume that the gravity adjustment scale provides for a deduction of \$0.02 per 1/10 degree API gravity below 34°. Normalized to 23.5° (the gravity of the oil being valued under this section), the prices of each of the volumes that the refiner purchased that are included in the volume-weighted average calculation are as follows:

10,000 bbl	24.5°	\$34.50	(1.0° difference over 23.5° = \$0.20 deducted).
9,000 bbl	23.0°	33.35	(0.5° difference under 23.5° = \$0.10 added).
4,000 bbl	22.0°	33.30	(1.5° difference under 23.5° = \$0.30 added).

3. The volume-weighted average price is  $((10,000 \text{ bbl} \times \$34.50/\text{bbl}) + (9,000 \text{ bbl} \times \$33.35/\text{bbl}) + (4,000 \text{ bbl} \times \$33.30/\text{bbl})) / 23,000 \text{ bbl} = \$33.84/\text{bbl}$ . That price will be the value of the oil produced from the lease and refined prior to an arm's-length sale, under this section.

(c) If you value oil under this section, MMS will allow a deduction, under §§206.56 and 206.57, for the reasonable, actual costs:

(1) That you incur to transport oil that you or your affiliate sell(s), which is included in the weighted-average price calculation, from the lease to the point where the oil is sold; and

(2) That the seller incurs to transport oil that you or your affiliate purchase(s), which is included in the weighted-average cost calculation, from the property where it is produced to the point where you or your affiliate purchase(s) it. You may not deduct any costs of gathering as part of a transportation deduction or allowance.

(d) If paragraphs (a) and (b) of this section result in an unreasonable value for your production as a result of circumstances regarding that production, the MMS Director may establish an alternative valuation method.

(e) You must also comply with §206.54.

[72 FR 71241, Dec. 17, 2007]

#### § 206.54 How do I fulfill the lease provision regarding valuing production on the basis of the major portion of like-quality oil?



(a) For any Indian leases that provide that the Secretary may consider the highest price paid or offered for a major portion of production (major portion) in determining value for royalty purposes, if data are available to compute a major portion, MMS will, where practicable, compare the value determined in accordance with this section with the major portion. The value to be used in determining the value of production, for royalty purposes, will be the higher of those two values.

(b) For purposes of this paragraph, major portion means the highest price paid or offered at the time of production for the major portion of oil production from the same field. The major portion will be calculated using like-quality oil sold under arm's-length contracts from the same field (or, if necessary to obtain a reasonable sample, from the same area) for each month. All such oil production will be arrayed from highest price to lowest price (at the bottom). The major portion is that price at which 50 percent by volume plus one barrel of oil (starting from the bottom) is sold.

[72 FR 71241, Dec. 17, 2007]

#### § 206.55 What are my responsibilities to place production into marketable condition and to market the production?



You must place oil in marketable condition and market the oil for the mutual benefit of yourself and the Indian lessor at no cost to the lessor, unless the lease agreement provides otherwise. If, in the process

of marketing the oil or placing it in marketable condition, your gross proceeds are reduced because services are performed on your behalf that would be your responsibility, and if you valued the oil using your or your affiliate's gross proceeds (or gross proceeds received in the sale of oil received in exchange) under §206.52, you must increase value to the extent that your gross proceeds are reduced.

[72 FR 71241, Dec. 17, 2007]

#### § 206.56 Transportation allowances—general.



[top](#)

(a) Where the value of oil has been determined under §206.52 or §206.53 of this subpart at a point (e.g., sales point or point of value determination) off the lease, MMS shall allow a deduction for the reasonable, actual costs incurred by the lessee to transport oil to a point off the lease; provided, however, that no transportation allowance will be granted for transporting oil taken as Royalty-In-Kind (RIK); or

(b)(1) Except as provided in paragraph (b)(2) of this section, the transportation allowance deduction on the basis of a sales type code may not exceed 50 percent of the value of the oil at the point of sale as determined under §206.52 of this subpart. Transportation costs cannot be transferred between sales type codes or to other products.

(2) Upon request of a lessee, MMS may approve a transportation allowance deduction in excess of the limitation prescribed by paragraph (b)(1) of this section. The lessee must demonstrate that the transportation costs incurred in excess of the limitation prescribed in paragraph (b)(1) of this section were reasonable, actual, and necessary. An application for exception (using Form MMS-4393, Request to Exceed Regulatory Allowance Limitation) must contain all relevant and supporting documentation necessary for MMS to make a determination. Under no circumstances may the value, for royalty purposes, under any sales type code, be reduced to zero.

(c) Transportation costs must be allocated among all products produced and transported as provided in §206.57. Transportation allowances for oil shall be expressed as dollars per barrel.

(d) If, after a review or audit, MMS determines that a lessee has improperly determined a transportation allowance authorized by this subpart, then the lessee will pay any additional royalties, plus interest determined in accordance with 30 CFR 218.54, or will be entitled to a credit without interest.

[61 FR 5455, Feb. 12, 1996. Redesignated and amended at 72 FR 71241, Dec. 17, 2007; 73 FR 15890, Mar. 26, 2008]

#### § 206.57 Determination of transportation allowances.



[top](#)

(a) *Arm's-length transportation contracts.* (1)(i) For transportation costs incurred by a lessee under an arm's-length contract, the transportation allowance shall be the reasonable, actual costs incurred by the lessee for transporting oil under that contract, except as provided in paragraphs (a)(1)(ii) and (a)(1)(iii) of this section, subject to monitoring, review, audit, and adjustment. The lessee shall have the burden of demonstrating that its contract is arm's-length. Such allowances shall be subject to the provisions of paragraph (f) of this section. Before any deduction may be taken, the lessee must submit a completed page one of Form MMS-4110 (and Schedule 1), Oil Transportation Allowance Report, in accordance with paragraph (c)(1) of this section. A transportation 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-4110 is filed with MMS, unless MMS approves a longer period upon a showing of good cause by the lessee.

(ii) In conducting reviews and audits, MMS will examine whether the contract reflects more than the consideration actually transferred either directly or indirectly from the lessee to the transporter for the transportation. If the contract reflects more than the total consideration, then MMS may require that the transportation allowance be determined in accordance with paragraph (b) of this section.

(iii) If MMS determines that the consideration paid under an arm's-length transportation contract does not reflect the reasonable value of the transportation because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then MMS shall require that the transportation allowance be determined in accordance with paragraph (b) of this section. When MMS determines that the value of the transportation may be unreasonable, MMS will notify the lessee and

give the lessee an opportunity to provide written information justifying the lessee's transportation costs.

(2)(i) If an arm's-length transportation contract includes more than one liquid product, and the transportation costs attributable to each product cannot be determined from the contract, then the total transportation costs shall be allocated in a consistent and equitable manner to each of the liquid products transported in the same proportion as the ratio of the volume of each product (excluding waste products which have no value) to the volume of all liquid products (excluding waste products which have no value). Except as provided in this paragraph, no allowance may be taken for the costs of transporting lease production which is not royalty-bearing without MMS approval.

(ii) Notwithstanding the requirements of paragraph (i), the lessee may propose to MMS a cost allocation method on the basis of the values of the products transported. MMS shall approve the method unless it determines that it is not consistent with the purposes of the regulations in this part.

(3) If an arm's-length transportation contract includes both gaseous and liquid products, and the transportation costs attributable to each product cannot be determined from the contract, the lessee shall propose an allocation procedure to MMS. The lessee may use the oil transportation allowance determined in accordance with its proposed allocation procedure until MMS issues its determination on the acceptability of the cost allocation. The lessee shall submit all available data to support its proposal. The initial proposal must be submitted by June 30, 1988 or within 3 months after the last day of the month for which the lessee requests a transportation allowance, whichever is later (unless MMS approves a longer period). MMS shall then determine the oil transportation allowance based upon the lessee's proposal and any additional information MMS deems necessary.

(4) Where the lessee's payments for transportation under an arm's-length contract are not on a dollar-per-unit basis, the lessee shall convert whatever consideration is paid to a dollar value equivalent for the purposes of this section.

(5) Where an arm's-length sales contract price, or a posted price, includes a provision whereby the listed price is reduced by a transportation factor, MMS will not consider the transportation factor to be a transportation allowance. The transportation factor may be used in determining the lessee's gross proceeds for the sale of the product. The transportation factor may not exceed 50 percent of the base price of the product without MMS approval.

(b) *Non-arm's-length or no contract.* (1) If a lessee has a non-arm's-length transportation contract or has no contract, including those situations where the lessee performs transportation services for itself, the transportation allowance will be based upon the lessee's reasonable, actual costs as provided in this paragraph. All transportation allowances deducted under a non-arm's-length or no-contract situation are subject to monitoring, review, audit, and adjustment. Before any estimated or actual deduction may be taken, the lessee must submit a completed Form MMS-4110 in its entirety in accordance with paragraph (c)(2) of this section. A transportation 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-4110 is filed with MMS, unless MMS approves a longer period upon a showing of good cause by the lessee. MMS will monitor the allowance deductions to determine whether lessees are taking deductions that are reasonable and allowable. When necessary or appropriate, MMS may direct a lessee to modify its actual transportation allowance deduction.

(2) The transportation allowance for non-arm's-length or no-contract situations shall be based upon the lessee's actual costs for transportation during the reporting period, including operating and maintenance expenses, overhead, and either depreciation and a return on undepreciated capital investment in accordance with paragraph (b)(2)(iv)(A) of this section, or a cost equal to the initial capital investment in the transportation system multiplied by a rate of return in accordance with paragraph (b)(2)(iv)(B) of this section. Allowable capital costs are generally those for depreciable fixed assets (including costs of delivery and installation of capital equipment) which are an integral part of the transportation system.

(i) Allowable operating expenses include: Operations supervision and engineering; operations labor; fuel; utilities; materials; ad valorem property taxes; rent; supplies; and any other directly allocable and attributable operating expense which the lessee can document.

(ii) Allowable maintenance expenses include: Maintenance of the transportation system; maintenance of equipment; maintenance labor; and other directly allocable and attributable maintenance expenses which the lessee can document.

(iii) Overhead directly attributable and allocable to the operation and maintenance of the transportation system is an allowable expense. State and Federal income taxes and severance taxes and other fees, including royalties, are not allowable expenses.

(iv) A lessee may use either depreciation or a return on depreciable capital investment. After a lessee has elected to use either method for a transportation system, the lessee may not later elect to change to

the other alternative without approval of MMS.

(A) To compute depreciation, the lessee may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves which the transportation system services or on a unit-of-production method. After an election is made, the lessee may not change methods without MMS approval. A change in ownership of a transportation system shall not alter the depreciation schedule established by the original transporter/lessee for purposes of the allowance calculation. With or without a change in ownership, a transportation system shall be depreciated only once. Equipment shall not be depreciated below a reasonable salvage value.

(B) MMS shall allow as a cost an amount equal to the initial capital investment in the transportation system multiplied by the rate of return determined under paragraph (b)(2)(v) of this section. No allowance shall be provided for depreciation. This alternative shall apply only to transportation facilities first placed in service after March 1, 1988.

(v) The rate of return shall be the industrial rate associated with Standard and Poor's BBB rating. The rate of return shall be the monthly average rate as published in Standard and Poor's Bond Guide for the first month of the reporting period for which the allowance is applicable and shall be effective during the reporting period. The rate shall be redetermined at the beginning of each subsequent transportation allowance reporting period (which is determined under paragraph (c) of this section).

(3)(i) The deduction for transportation costs shall be determined on the basis of the lessee's cost of transporting each product through each individual transportation system. Where more than one liquid product is transported, allocation of costs to each of the liquid products transported shall be in the same proportion as the ratio of the volume of each liquid product (excluding waste products which have no value) to the volume of all liquid products (excluding waste products which have no value) and such allocation shall be made in a consistent and equitable manner. Except as provided in this paragraph, the lessee may not take an allowance for transporting lease production which is not royalty-bearing without MMS approval.

(ii) Notwithstanding the requirements of paragraph (i), the lessee may propose to MMS a cost allocation method on the basis of the values of the products transported. MMS shall approve the method unless it determines that it is not consistent with the purposes of the regulations in this part.

(4) Where both gaseous and liquid products are transported through the same transportation system, the lessee shall propose a cost allocation procedure to MMS. The lessee may use the oil transportation allowance determined in accordance with its proposed allocation procedure until MMS issues its determination on the acceptability of the cost allocation. The lessee shall submit all available data to support its proposal. The initial proposal must be submitted by June 30, 1988 or within 3 months after the last day of the month for which the lessee requests a transportation allowance, whichever is later (unless MMS approves a longer period). MMS shall then determine the oil transportation allowance on the basis of the lessee's proposal and any additional information MMS deems necessary.

(5) A lessee may apply to MMS for an exception from the requirement that it compute actual costs in accordance with paragraphs (b)(1) through (b)(4) of this section. MMS will grant the exception only if the lessee has a tariff for the transportation system approved by the Federal Energy Regulatory Commission (FERC) for Indian leases. MMS shall deny the exception request if it determines that the tariff is excessive as compared to arm's-length transportation charges by pipelines, owned by the lessee or others, providing similar transportation services in that area. If there are no arm's-length transportation charges, MMS shall deny the exception request if:

(i) No FERC cost analysis exists and the FERC has declined to investigate under MMS timely objections upon filing; and

(ii) the tariff significantly exceeds the lessee's actual costs for transportation as determined under this section.

(c) *Reporting requirements* —(1) *Arm's-length contracts.* (i) With the exception of those transportation allowances specified in paragraphs (c)(1)(v) and (c)(1)(vi) of this section, the lessee shall submit page one of the initial Form MMS-4110 (and Schedule 1), Oil Transportation Allowance Report, prior to, or at the same time as, the transportation allowance determined, under an arm's-length contract, is reported on Form MMS-2014, Report of Sales and Royalty Remittance. A Form MMS-4110 received by the end of the month that the Form MMS-2014 is due shall be considered to be timely received.

(ii) The initial Form MMS-4110 shall be effective for a reporting period beginning the month that the lessee is first authorized to deduct a transportation allowance and shall continue until the end of the calendar year, or until the applicable contract or rate terminates or is modified or amended, whichever is earlier.

(iii) After the initial reporting period and for succeeding reporting periods, lessees must submit page one of Form MMS-4110 (and Schedule 1) within 3 months after the end of the calendar year, or after the applicable contract or rate terminates or is modified or amended, whichever is earlier, unless MMS approves a longer period (during which period the lessee shall continue to use the allowance from the previous reporting period).

(iv) MMS may require that a lessee submit arm's-length transportation contracts, production agreements, operating agreements, and related documents. Documents shall be submitted within a reasonable time, as determined by MMS.

(v) Transportation allowances which are based on arm's-length contracts and which are in effect at the time these regulations become effective will be allowed to continue until such allowances terminate. For the purposes of this section, only those allowances that have been approved by MMS in writing shall qualify as being in effect at the time these regulations become effective.

(vi) MMS may establish, in appropriate circumstances, reporting requirements which are different from the requirements of this section.

(2) *Non-arm's-length or no contract.* (i) With the exception of those transportation allowances specified in paragraphs (c)(2)(v), (c)(2)(vii) and (c)(2)(viii) of this section, the lessee shall submit an initial Form MMS-4110 prior to, or at the same time as, the transportation allowance determined under a non-arm's-length contract or no-contract situation is reported on Form MMS-2014. A Form MMS-4110 received by the end of the month that the Form MMS-2014 is due shall be considered to be timely received. The initial report may be based upon estimated costs.

(ii) The initial Form MMS-4110 shall be effective for a reporting period beginning the month that the lessee first is authorized to deduct a transportation allowance and shall continue until the end of the calendar year, or until transportation under the non-arm's-length contract or the no-contract situation terminates, whichever is earlier.

(iii) For calendar-year reporting periods succeeding the initial reporting period, the lessee shall submit a completed Form MMS-4110 containing the actual costs for the previous reporting period. If oil transportation is continuing, the lessee shall include on Form MMS-4110 its estimated costs for the next calendar year. The estimated oil transportation allowance shall be based on the actual costs for the previous reporting period plus or minus any adjustments which are based on the lessee's knowledge of decreases or increases that will affect the allowance. MMS must receive the Form MMS-4110 within 3 months after the end of the previous reporting period, unless MMS approves a longer period (during which period the lessee shall continue to use the allowance from the previous reporting period).

(iv) For new transportation facilities or arrangements, the lessee's initial Form MMS-4110 shall include estimates of the allowable oil transportation costs for the applicable period. Cost estimates shall be based upon the most recently available operations data for the transportation system or, if such data are not available, the lessee shall use estimates based upon industry data for similar transportation systems.

(v) Non-arm's-length contract or no-contract transportation allowances which are in effect at the time these regulations become effective will be allowed to continue until such allowances terminate. For the purposes of this section, only those allowances that have been approved by MMS in writing shall qualify as being in effect at the time these regulations become effective.

(vi) Upon request by MMS, the lessee shall submit all data used to prepare its Form MMS-4110. The data shall be provided within a reasonable period of time, as determined by MMS.

(vii) MMS may establish, in appropriate circumstances, reporting requirements which are different from the requirements of this section.

(viii) If the lessee is authorized to use its FERC-approved tariff as its transportation cost in accordance with paragraph (b)(5) of this section, it shall follow the reporting requirements of paragraph (c)(1) of this section.

(3) MMS may establish reporting dates for individual lessees different from those specified in this subpart in order to provide more effective administration. Lessees will be notified of any change in their reporting period.

(4) Transportation allowances must be reported as a separate entry on Form MMS-2014, unless MMS approves a different reporting procedure.

(d) *Interest assessments for incorrect or late reports and for failure to report.* (1) If a lessee deducts a

transportation allowance on its Form MMS-2014 without complying with the requirements of this section, the lessee shall pay interest only on the amount of such deduction until the requirements of this section are complied with. The lessee also shall repay the amount of any allowance which is disallowed by this section.

(2) If a lessee erroneously reports a transportation allowance which results in an underpayment of royalties, interest shall be paid on the amount of that underpayment.

(3) Interest required to be paid by this section shall be determined in accordance with 30 CFR 218.54.

(e) *Adjustments.* (1) If the actual transportation allowance is less than the amount the lessee has taken on Form MMS-2014 for each month during the allowance form reporting period, the lessee must pay additional royalties due plus interest computed under 30 CFR 218.54, retroactive to the first day of the first month the lessee is authorized to deduct a transportation allowance. If the actual transportation allowance is greater than the amount the lessee has taken on Form MMS-2014 for each month during the allowance form reporting period, the lessee will be entitled to a credit without interest.

(2) For lessees transporting production from Indian leases, the lessee must submit a corrected Form MMS-2014 to reflect actual costs, together with any payment, in accordance with instructions provided by MMS.

(f) *Actual or theoretical losses.* Notwithstanding any other provisions of this subpart, for other than arm's-length contracts, no cost shall be allowed for oil transportation which results from payments (either volumetric or for value) for actual or theoretical losses. This section does not apply when the transportation allowance is based upon a FERC or State regulatory agency approved tariff.

(g) *Other transportation cost determinations.* The provisions of this section shall apply to determine transportation costs when establishing value using a netback valuation procedure or any other procedure that requires deduction of transportation costs.

[61 FR 5455, Feb. 12, 1996. Redesignated at 72 FR 71241, Dec. 17, 2007, as amended at 73 FR 15890, Mar. 26, 2008]

#### § 206.58 What must I do if MMS finds that I have not properly determined value?



[top](#)

(a) If MMS finds that you have not properly determined value, you must:

(1) Pay the difference, if any, between the royalty payments you made and those that are due, based upon the value MMS establishes; and

(2) Pay interest on the difference computed under §218.54 of this chapter.

(b) If you are entitled to a credit due to overpayment on Indian leases, see §218.53 of this chapter. The credit will be without interest.

[72 FR 71244, Dec. 17, 2007]

#### § 206.59 May I ask MMS for valuation guidance?



[top](#)

You may ask MMS for guidance in determining value. You may propose a value method to MMS. Submit all available data related to your proposal and any additional information MMS deems necessary. We will promptly review your proposal and provide you with non-binding guidance.

[72 FR 71244, Dec. 17, 2007]

#### § 206.60 What are the quantity and quality bases for royalty settlement?



[top](#)

(a) You must compute royalties on the quantity and quality of oil as measured at the point of settlement approved by BLM for the lease.

(b) If you determine the value of oil under §§206.52, 206.53, or 206.54 of this subpart based on a quantity or quality different from the quantity or quality at the point of royalty settlement approved by BLM for the lease, you must adjust the value for those quantity or quality differences.

(c) You may not deduct from the royalty volume or royalty value actual or theoretical losses incurred before the royalty settlement point unless BLM determines that any actual loss was unavoidable.

[72 FR 71244, Dec. 17, 2007]

#### **§ 206.61 What records must I keep and produce?**



[top](#)

(a) On request, you must make available sales, volume, and transportation data for production you sold, purchased, or obtained from the field or area. You must make this data available to MMS, Indian representatives, or other authorized persons.

(b) You must retain all data relevant to the determination of royalty value. Document retention and recordkeeping requirements are found at §§207.5, 212.50, and 212.51 of this chapter. The MMS, Indian representatives, or other authorized persons may review and audit such data you possess, and MMS will direct you to use a different value if it determines that the reported value is inconsistent with the requirements of this subpart or the lease.

[72 FR 71244, Dec. 17, 2007]

#### **§ 206.62 Does MMS protect information I provide?**



[top](#)

The MMS will keep confidential, to the extent allowed under applicable laws and regulations, any data or other information you submit that is privileged, confidential, or otherwise exempt from disclosure. All requests for information must be submitted under the Freedom of Information Act regulations of the Department of the Interior, 43 CFR part 2.

[72 FR 71244, Dec. 17, 2007]

### **Subpart C—Federal Oil**



[top](#)

**Source:** 65 FR 14088, Mar. 15, 2000, unless otherwise noted.

#### **§ 206.100 What is the purpose of this subpart?**



[top](#)

(a) This subpart applies to all oil produced from Federal oil and gas leases onshore and on the Outer Continental Shelf (OCS). It explains how you as a lessee must calculate the value of production for royalty purposes consistent with the mineral leasing laws, other applicable laws, and lease terms.

(b) If you are a designee and if you dispose of production on behalf of a lessee, the terms "you" and "your" in this subpart refer to you and not to the lessee. In this circumstance, you must determine and report royalty value for the lessee's oil by applying the rules in this subpart to your disposition of the lessee's oil.

(c) If you are a designee and only report for a lessee, and do not dispose of the lessee's production, references to "you" and "your" in this subpart refer to the lessee and not the designee. In this circumstance, you as a designee must determine and report royalty value for the lessee's oil by applying the rules in this subpart to the lessee's disposition of its oil.

(d) If the regulations in this subpart are inconsistent with:

(1) A Federal statute;

(2) A settlement agreement between the United States and a lessee resulting from administrative or judicial litigation;

(3) A written agreement between the lessee and the MMS Director establishing a method to determine the value of production from any lease that MMS expects at least would approximate the value established under this subpart; or

(4) An express provision of an oil and gas lease subject to this subpart, then the statute, settlement agreement, written agreement, or lease provision will govern to the extent of the inconsistency.

(e) MMS may audit and adjust all royalty payments.

#### **§ 206.101 What definitions apply to this subpart?**



[top](#)

The following definitions apply to this subpart:

*Affiliate* means a person who controls, is controlled by, or is under common control with another person. For purposes of this subpart:

(1) Ownership or common ownership of more than 50 percent of the voting securities, or instruments of ownership, or other forms of ownership, of another person constitutes control. Ownership of less than 10 percent constitutes a presumption of noncontrol that MMS may rebut.

(2) If there is ownership or common ownership of 10 through 50 percent of the voting securities or instruments of ownership, or other forms of ownership, of another person, MMS will consider the following factors in determining whether there is control under the circumstances of a particular case:

(i) The extent to which there are common officers or directors;

(ii) With respect to the voting securities, or instruments of ownership, or other forms of ownership: the percentage of ownership or common ownership, the relative percentage of ownership or common ownership compared to the percentage(s) of ownership by other persons, whether a person is the greatest single owner, or whether there is an opposing voting bloc of greater ownership;

(iii) Operation of a lease, plant, or other facility;

(iv) The extent of participation by other owners in operations and day-to-day management of a lease, plant, or other facility; and

(v) Other evidence of power to exercise control over or common control with another person.

(3) Regardless of any percentage of ownership or common ownership, relatives, either by blood or marriage, are affiliates.

*ANS* means Alaska North Slope (ANS).

*Area* means a geographic region at least as large as the limits of an oil field, in which oil has similar quality, economic, and legal characteristics.

*Arm's-length contract* means a contract or agreement between independent persons who are not affiliates and who have opposing economic interests regarding that contract. To be considered arm's length for any production month, a contract must satisfy this definition for that month, as well as when the contract was executed.

*Audit* means a review, conducted under generally accepted accounting and auditing standards, of royalty payment compliance activities of lessees, designees or other persons who pay royalties, rents, or bonuses on Federal leases.

*BLM* means the Bureau of Land Management of the Department of the Interior.

*Condensate* means liquid hydrocarbons (normally exceeding 40 degrees of API gravity) recovered at the surface without processing. Condensate is the mixture of liquid hydrocarbons resulting from condensation of petroleum hydrocarbons existing initially in a gaseous phase in an underground reservoir.

*Contract* means any oral or written agreement, including amendments or revisions, between two or more persons, that is enforceable by law and that with due consideration creates an obligation.

*Designee* means the person the lessee designates to report and pay the lessee's royalties for a lease.

*Exchange agreement* means an agreement where one person agrees to deliver oil to another person at a specified location in exchange for oil deliveries at another location. Exchange agreements may or may not specify prices for the oil involved. They frequently specify dollar amounts reflecting location, quality, or other differentials. Exchange agreements include buy/sell agreements, which specify prices to be paid at each exchange point and may appear to be two separate sales within the same agreement. Examples of other types of exchange agreements include, but are not limited to, exchanges of produced oil for specific types of crude oil (e.g., West Texas Intermediate); exchanges of produced oil for other crude oil at other locations (Location Trades); exchanges of produced oil for other grades of oil (Grade Trades); and multi-party exchanges.

*Field* means a geographic region situated over one or more subsurface oil and gas reservoirs and encompassing at least the outermost boundaries of all oil and gas accumulations known within those reservoirs, vertically projected to the land surface. State oil and gas regulatory agencies usually name onshore fields and designate their official boundaries. MMS names and designates boundaries of OCS fields.

*Gathering* means the movement of lease production to a central accumulation or treatment point on the lease, unit, or communitized area, or to a central accumulation or treatment point off the lease, unit, or communitized area that BLM or MMS approves for onshore and offshore leases, respectively.

*Gross proceeds* means the total monies and other consideration accruing for the disposition of oil produced. Gross proceeds also include, but are not limited to, the following examples:

- (1) Payments for services such as dehydration, marketing, measurement, or gathering which the lessee must perform at no cost to the Federal Government;
- (2) The value of services, such as salt water disposal, that the producer normally performs but that the buyer performs on the producer's behalf;
- (3) Reimbursements for harboring or terminaling fees;
- (4) Tax reimbursements, even though the Federal royalty interest may be exempt from taxation;
- (5) Payments made to reduce or buy down the purchase price of oil to be produced in later periods, by allocating such payments over the production whose price the payment reduces and including the allocated amounts as proceeds for the production as it occurs; and
- (6) Monies and all other consideration to which a seller is contractually or legally entitled, but does not seek to collect through reasonable efforts.

*Lease* means any 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 oil or gas—or the land area covered by that authorization, whichever the context requires.

*Lessee* means any person to whom the United States issues an oil and gas lease, an assignee of all or a part of the record title interest, or any person to whom operating rights in a lease have been assigned.

*Location differential* means an amount paid or received (whether in money or in barrels of oil) under an exchange agreement that results from differences in location between oil delivered in exchange and oil received in the exchange. A location differential may represent all or part of the difference between the price received for oil delivered and the price paid for oil received under a buy/sell exchange agreement.

*Market center* means a major point MMS recognizes for oil sales, refining, or transshipment. Market

centers generally are locations where MMS-approved publications publish oil spot prices.

*Marketable condition* means oil sufficiently free from impurities and otherwise in a condition a purchaser will accept under a sales contract typical for the field or area.

*MMS-approved publication* means a publication MMS approves for determining ANS spot prices or WTI differentials.

*Netting* means reducing the reported sales value to account for transportation instead of reporting a transportation allowance as a separate entry on Form MMS-2014.

*NYMEX price* means the average of the New York Mercantile Exchange (NYMEX) settlement prices for light sweet crude oil delivered at Cushing, Oklahoma, calculated as follows:

(1) Sum the prices published for each day during the calendar month of production (excluding weekends and holidays) for oil to be delivered in the prompt month corresponding to each such day; and

(2) Divide the sum by the number of days on which those prices are published (excluding weekends and holidays).

*Oil* means a mixture of hydrocarbons that existed in the liquid phase in natural underground reservoirs, remains liquid at atmospheric pressure after passing through surface separating facilities, and is marketed or used as a liquid. Condensate recovered in lease separators or field facilities is oil.

*Outer Continental Shelf (OCS)* means all submerged lands lying seaward and outside of the area of lands beneath navigable waters as defined in Section 2 of the Submerged Lands Act (43 U.S.C. 1301) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

*Person* means any individual, firm, corporation, association, partnership, consortium, or joint venture (when established as a separate entity).

*Prompt month* means the nearest month of delivery for which NYMEX futures prices are published during the trading month.

*Quality differential* means an amount paid or received under an exchange agreement (whether in money or in barrels of oil) that results from differences in API gravity, sulfur content, viscosity, metals content, and other quality factors between oil delivered and oil received in the exchange. A quality differential may represent all or part of the difference between the price received for oil delivered and the price paid for oil received under a buy/sell agreement.

*Rocky Mountain Region* means the States of Colorado, Montana, North Dakota, South Dakota, Utah, and Wyoming, except for those portions of the San Juan Basin and other oil-producing fields in the "Four Corners" area that lie within Colorado and Utah.

*Roll* means an adjustment to the NYMEX price that is calculated as follows:

$$\text{Roll} = .6667 \times (P_0 - P_1) + .3333 \times (P_0 - P_2)$$
where:  $P_0$  = the average of the daily NYMEX settlement prices for deliveries during the prompt month that is the same as the month of production, as published for each day during the trading month for which the month of production is the prompt month;  $P_1$  = the average of the daily NYMEX settlement prices for deliveries during the month following the month of production, published for each day during the trading month for which the month of production is the prompt month; and  $P_2$  = the average of the daily NYMEX settlement prices for deliveries during the second month following the month of production, as published for each day during the trading month for which the month of production is the prompt month. Calculate the average of the daily NYMEX settlement prices using only the days on which such prices are published (excluding weekends and holidays).

(1) *Example 1. Prices in Out Months are Lower Going Forward:* The month of production for which you must determine royalty value is March. March was the prompt month (for year 2003) from January 22 through February 20. April was the first month following the month of production, and May was the second month following the month of production.  $P_0$  therefore is the average of the daily NYMEX settlement prices for deliveries during March published for each business day between January 22 and February 20.  $P_1$  is the average of the daily NYMEX settlement prices for deliveries during April published for each business day between January 22 and February 20.  $P_2$  is the average of the daily NYMEX

settlement prices for deliveries during May published for each business day between January 22 and February 20. In this example, assume that  $P_0 = \$28.00$  per bbl,  $P_1 = \$27.70$  per bbl, and  $P_2 = \$27.10$  per bbl. In this example (a declining market),  $\text{Roll} = .6667 \times (\$28.00 - \$27.70) + .3333 \times (\$28.00 - \$27.10) = \$.20 + \$.30 = \$.50$ . You add this number to the NYMEX price.

(2) *Example 2. Prices in Out Months are Higher Going Forward:* The month of production for which you must determine royalty value is July. July 2003 was the prompt month from May 21 through June 20. August was the first month following the month of production, and September was the second month following the month of production.  $P_0$  therefore is the average of the daily NYMEX settlement prices for deliveries during July published for each business day between May 21 and June 20.  $P_1$  is the average of the daily NYMEX settlement prices for deliveries during August published for each business day between May 21 and June 20.  $P_2$  is the average of the daily NYMEX settlement prices for deliveries during September published for each business day between May 21 and June 20. In this example, assume that  $P_0 = \$28.00$  per bbl,  $P_1 = \$28.90$  per bbl, and  $P_2 = \$29.50$  per bbl. In this example (a rising market),  $\text{Roll} = .6667 \times (\$28.00 - \$28.90) + .3333 \times (\$28.00 - \$29.50) = (-\$ .60) + (-\$ .50) = -\$1.10$ . You add this negative number to the NYMEX price (effectively a subtraction from the NYMEX price).

*Sale* means a contract between two persons where:

- (1) The seller unconditionally transfers title to the oil to the buyer and does not retain any related rights such as the right to buy back similar quantities of oil from the buyer elsewhere;
- (2) The buyer pays money or other consideration for the oil; and
- (3) The parties' intent is for a sale of the oil to occur.

*Spot price* means the price under a spot sales contract where:

- (1) A seller agrees to sell to a buyer a specified amount of oil at a specified price over a specified period of short duration;
- (2) No cancellation notice is required to terminate the sales agreement; and
- (3) There is no obligation or implied intent to continue to sell in subsequent periods.

*Tendering program* means a producer's offer of a portion of its crude oil produced from a field or area for competitive bidding, regardless of whether the production is offered or sold at or near the lease or unit or away from the lease or unit.

*Trading month* means the period extending from the second business day before the 25th day of the second calendar month preceding the delivery month (or, if the 25th day of that month is a non-business day, the second business day before the last business day preceding the 25th day of that month) through the third business day before the 25th day of the calendar month preceding the delivery month (or, if the 25th day of that month is a non-business day, the third business day before the last business day preceding the 25th day of that month), unless the NYMEX publishes a different definition or different dates on its official Web site, [www.nymex.com](http://www.nymex.com), in which case the NYMEX definition will apply.

*Transportation allowance* means a deduction in determining royalty value for the reasonable, actual costs of moving oil to a point of sale or delivery off the lease, unit area, or communitized area. The transportation allowance does not include gathering costs.

*WTI differential* means the average of the daily mean differentials for location and quality between a grade of crude oil at a market center and West Texas Intermediate (WTI) crude oil at Cushing published for each day for which price publications perform surveys for deliveries during the production month, calculated over the number of days on which those differentials are published (excluding weekends and holidays). Calculate the daily mean differentials by averaging the daily high and low differentials for the month in the selected publication. Use only the days and corresponding differentials for which such differentials are published.

- (1) *Example.* Assume the production month was March 2003. Industry trade publications performed their price surveys and determined differentials during January 26 through February 25 for oil delivered in March. The WTI differential (for example, the West Texas Sour crude at Midland, Texas, spread versus WTI) applicable to valuing oil produced in the March 2003 production month would be determined using all the business days for which differentials were published during the period January 26 through February 25 excluding weekends and holidays (22 days). To calculate the WTI differential, add together all of the daily mean differentials published for January 26 through February 25 and divide that sum by

22.

(2) [Reserved]

[65 FR 14088, Mar. 15, 2000, as amended at 69 FR 24975, May 5, 2004]

**§ 206.102 How do I calculate royalty value for oil that I or my affiliate sell(s) under an arm's-length contract?**[top](#)

(a) The value of oil under this section is the gross proceeds accruing to the seller under the arm's-length contract, less applicable allowances determined under §§206.110 or 206.111. This value does not apply if you exercise an option to use a different value provided in paragraph (d)(1) or (d)(2)(i) of this section, or if one of the exceptions in paragraph (c) of this section applies. Use this paragraph (a) to value oil that:

(1) You sell under an arm's-length sales contract; or

(2) You sell or transfer to your affiliate or another person under a non-arm's-length contract and that affiliate or person, or another affiliate of either of them, then sells the oil under an arm's-length contract, unless you exercise the option provided in paragraph (d)(2)(i) of this section.

(b) If you have multiple arm's-length contracts to sell oil produced from a lease that is valued under paragraph (a) of this section, the value of the oil is the volume-weighted average of the values established under this section for each contract for the sale of oil produced from that lease.

(c) This paragraph contains exceptions to the valuation rule in paragraph (a) of this section. Apply these exceptions on an individual contract basis.

(1) In conducting reviews and audits, if MMS determines that any arm's-length sales contract does not reflect the total consideration actually transferred either directly or indirectly from the buyer to the seller, MMS may require that you value the oil sold under that contract either under §206.103 or at the total consideration received.

(2) You must value the oil under §206.103 if MMS determines that the value under paragraph (a) of this section does not reflect the reasonable value of the production due to either:

(i) Misconduct by or between the parties to the arm's-length contract; or

(ii) Breach of your duty to market the oil for the mutual benefit of yourself and the lessor.

(A) MMS will not use this provision to simply substitute its judgment of the market value of the oil for the proceeds received by the seller under an arm's-length sales contract.

(B) The fact that the price received by the seller under an arm's length contract is less than other measures of market price, such as index prices, is insufficient to establish breach of the duty to market unless MMS finds additional evidence that the seller acted unreasonably or in bad faith in the sale of oil from the lease.

(d)(1) If you enter into an arm's-length exchange agreement, or multiple sequential arm's-length exchange agreements, and following the exchange(s) you or your affiliate sell(s) the oil received in the exchange(s) under an arm's-length contract, then you may use either §206.102(a) or §206.103 to value your production for royalty purposes.

(i) If you use §206.102(a), your gross proceeds are the gross proceeds under your or your affiliate's arm's-length sales contract after the exchange(s) occur(s). You must adjust your gross proceeds for any location or quality differential, or other adjustments, you received or paid under the arm's-length exchange agreement(s). If MMS determines that any arm's-length exchange agreement does not reflect reasonable location or quality differentials, MMS may require you to value the oil under §206.103. You may not otherwise use the price or differential specified in an arm's-length exchange agreement to value your production.

(ii) When you elect under §206.102(d)(1) to use §206.102(a) or §206.103, you must make the same election for all of your production from the same unit, communitization agreement, or lease (if the lease

is not part of a unit or communitization agreement) sold under arm's-length contracts following arm's-length exchange agreements. You may not change your election more often than once every 2 years.

(2)(i) If you sell or transfer your oil production to your affiliate and that affiliate or another affiliate then sells the oil under an arm's-length contract, you may use either §206.102(a) or §206.103 to value your production for royalty purposes.

(ii) When you elect under §206.102(d)(2)(i) to use §206.102(a) or §206.103, you must make the same election for all of your production from the same unit, communitization agreement, or lease (if the lease is not part of a unit or communitization agreement) that your affiliates resell at arm's length. You may not change your election more often than once every 2 years.

(e) If you value oil under paragraph (a) of this section:

(1) MMS may require you to certify that your or your affiliate's arm's-length contract provisions include all of the consideration the buyer must pay, either directly or indirectly, for the oil.

(2) You must base value on the highest price the seller can receive through legally enforceable claims under the contract.

(i) If the seller fails to take proper or timely action to receive prices or benefits it is entitled to, you must pay royalty at a value based upon that obtainable price or benefit. But you will owe no additional royalties unless or until the seller receives monies or consideration resulting from the price increase or additional benefits, if:

(A) The seller makes timely application for a price increase or benefit allowed under the contract;

(B) The purchaser refuses to comply; and

(C) The seller takes reasonable documented measures to force purchaser compliance.

(ii) Paragraph (e)(2)(i) of this section will not permit you to avoid your royalty payment obligation where a purchaser fails to pay, pays only in part, or pays late. Any contract revisions or amendments that reduce prices or benefits to which the seller is entitled must be in writing and signed by all parties to the arm's-length contract.

### § 206.103 How do I value oil that is not sold under an arm's-length contract?



[top](#)

This section explains how to value oil that you may not value under §206.102 or that you elect under §206.102(d) to value under this section. First determine whether paragraph (a), (b), or (c) of this section applies to production from your lease, or whether you may apply paragraph (d) or (e) with MMS approval.

(a) *Production from leases in California or Alaska.* Value is the average of the daily mean ANS spot prices published in any MMS-approved publication during the trading month most concurrent with the production month. (For example, if the production month is June, compute the average of the daily mean prices using the daily ANS spot prices published in the MMS-approved publication for all the business days in June.)

(1) To calculate the daily mean spot price, average the daily high and low prices for the month in the selected publication.

(2) Use only the days and corresponding spot prices for which such prices are published.

(3) You must adjust the value for applicable location and quality differentials, and you may adjust it for transportation costs, under §206.112.

(4) After you select an MMS-approved publication, you may not select a different publication more often than once every 2 years, unless the publication you use is no longer published or MMS revokes its approval of the publication. If you are required to change publications, you must begin a new 2-year period.

(b) *Production from leases in the Rocky Mountain Region.* This paragraph provides methods and options

for valuing your production under different factual situations. You must consistently apply paragraph (b)(1), (b)(2), or (b)(3) of this section to value all of your production from the same unit, communitization agreement, or lease (if the lease or a portion of the lease is not part of a unit or communitization agreement) that you cannot value under §206.102 or that you elect under §206.102(d) to value under this section.

(1) If you have an MMS-approved tendering program, you must value oil produced from leases in the area the tendering program covers at the highest winning bid price for tendered volumes.

(i) The minimum requirements for MMS to approve your tendering program are:

(A) You must offer and sell at least 30 percent of your or your affiliates' production from both Federal and non-Federal leases in the area under your tendering program; and

(B) You must receive at least three bids for the tendered volumes from bidders who do not have their own tendering programs that cover some or all of the same area.

(ii) If you do not have an MMS-approved tendering program, you may elect to value your oil under either paragraph (b)(2) or (b)(3) of this section. After you select either paragraph (b)(2) or (b)(3) of this section, you may not change to the other method more often than once every 2 years, unless the method you have been using is no longer applicable and you must apply the other paragraph. If you change methods, you must begin a new 2-year period.

(2) Value is the volume-weighted average of the gross proceeds accruing to the seller under your or your affiliates' arm's-length contracts for the purchase or sale of production from the field or area during the production month.

(i) The total volume purchased or sold under those contracts must exceed 50 percent of your and your affiliates' production from both Federal and non-Federal leases in the same field or area during that month.

(ii) Before calculating the volume-weighted average, you must normalize the quality of the oil in your or your affiliates' arm's-length purchases or sales to the same gravity as that of the oil produced from the lease.

(3) Value is the NYMEX price (without the roll), adjusted for applicable location and quality differentials and transportation costs under §206.112.

(4) If you demonstrate to MMS's satisfaction that paragraphs (b)(1) through (b)(3) of this section result in an unreasonable value for your production as a result of circumstances regarding that production, the MMS Director may establish an alternative valuation method.

(c) *Production from leases not located in California, Alaska, or the Rocky Mountain Region.* (1) Value is the NYMEX price, plus the roll, adjusted for applicable location and quality differentials and transportation costs under §206.112.

(2) If the MMS Director determines that use of the roll no longer reflects prevailing industry practice in crude oil sales contracts or that the most common formula used by industry to calculate the roll changes, MMS may terminate or modify use of the roll under paragraph (c)(1) of this section at the end of each 2-year period following July 6, 2004, through notice published in the Federal Register not later than 60 days before the end of the 2-year period. MMS will explain the rationale for terminating or modifying the use of the roll in this notice.

(d) *Unreasonable value.* If MMS determines that the NYMEX price or ANS spot price does not represent a reasonable royalty value in any particular case, MMS may establish reasonable royalty value based on other relevant matters.

(e) *Production delivered to your refinery and the NYMEX price or ANS spot price is an unreasonable value.* (1) Instead of valuing your production under paragraph (a), (b), or (c) of this section, you may apply to the MMS Director to establish a value representing the market at the refinery if:

(i) You transport your oil directly to your or your affiliate's refinery, or exchange your oil for oil delivered to your or your affiliate's refinery; and

(ii) You must value your oil under this section at the NYMEX price or ANS spot price; and

(iii) You believe that use of the NYMEX price or ANS spot price results in an unreasonable royalty value.

(2) You must provide adequate documentation and evidence demonstrating the market value at the refinery. That evidence may include, but is not limited to:

(i) Costs of acquiring other crude oil at or for the refinery;

(ii) How adjustments for quality, location, and transportation were factored into the price paid for other oil;

(iii) Volumes acquired for and refined at the refinery; and

(iv) Any other appropriate evidence or documentation that MMS requires.

(3) If the MMS Director establishes a value representing market value at the refinery, you may not take an allowance against that value under §206.112(b) unless it is included in the Director's approval.

[65 FR 14088, Mar. 15, 2002, as amended at 67 FR 19111, Apr. 18, 2002; 69 FR 24976, May 5, 2004]

#### **§ 206.104 What publications are acceptable to MMS?**



[top](#)

(a) MMS periodically will publish in the Federal Register a list of acceptable publications for the NYMEX price and ANS spot price based on certain criteria, including, but not limited to:

(1) Publications buyers and sellers frequently use;

(2) Publications frequently mentioned in purchase or sales contracts;

(3) Publications that use adequate survey techniques, including development of estimates based on daily surveys of buyers and sellers of crude oil, and, for ANS spot prices, buyers and sellers of ANS crude oil; and

(4) Publications independent from MMS, other lessors, and lessees.

(b) Any publication may petition MMS to be added to the list of acceptable publications.

(c) MMS will specify the tables you must use in the acceptable publications.

(d) MMS may revoke its approval of a particular publication if it determines that the prices or differentials published in the publication do not accurately represent NYMEX prices or differentials or ANS spot market prices or differentials.

[65 FR 14088, Mar. 15, 2000, as amended at 69 FR 24976, May 5, 2004]

#### **§ 206.105 What records must I keep to support my calculations of value under this subpart?**



[top](#)

If you determine the value of your oil under this subpart, you must retain all data relevant to the determination of royalty value.

(a) You must be able to show:

(1) How you calculated the value you reported, including all adjustments for location, quality, and transportation, and

(2) How you complied with these rules.

(b) Recordkeeping requirements are found at part 207 of this chapter.

(c) MMS may review and audit your data, and MMS will direct you to use a different value if it determines that the reported value is inconsistent with the requirements of this subpart.

#### **§ 206.106 What are my responsibilities to place production into marketable condition and to market production?**



[top](#)

You must place oil in marketable condition and market the oil for the mutual benefit of the lessee and the lessor at no cost to the Federal Government. If you use gross proceeds under an arm's-length contract in determining value, you must increase those gross proceeds to the extent that the purchaser, or any other person, provides certain services that the seller normally would be responsible to perform to place the oil in marketable condition or to market the oil.

#### **§ 206.107 How do I request a value determination?**



[top](#)

(a) You may request a value determination from MMS regarding any Federal lease oil production. Your request must:

(1) Be in writing;

(2) Identify specifically all leases involved, the record title or operating rights owners of those leases, and the designees for those leases;

(3) Completely explain all relevant facts. You must inform MMS of any changes to relevant facts that occur before we respond to your request;

(4) Include copies of all relevant documents;

(5) Provide your analysis of the issue(s), including citations to all relevant precedents (including adverse precedents); and

(6) Suggest your proposed valuation method.

(b) MMS will reply to requests expeditiously. MMS may either:

(1) Issue a value determination signed by the Assistant Secretary, Land and Minerals Management; or

(2) Issue a value determination by MMS; or

(3) Inform you in writing that MMS will not provide a value determination. Situations in which MMS typically will not provide any value determination include, but are not limited to:

(i) Requests for guidance on hypothetical situations; and

(ii) Matters that are the subject of pending litigation or administrative appeals.

(c)(1) A value determination signed by the Assistant Secretary, Land and Minerals Management, is binding on both you and MMS until the Assistant Secretary modifies or rescinds it.

(2) After the Assistant Secretary issues a value determination, you must make any adjustments in royalty payments that follow from the determination and, if you owe additional royalties, pay late payment interest under 30 CFR 218.54.

(3) A value determination signed by the Assistant Secretary is the final action of the Department and is subject to judicial review under 5 U.S.C. 701-706.

(d) A value determination issued by MMS is binding on MMS and delegated States with respect to the

specific situation addressed in the determination unless the MMS (for MMS-issued value determinations) or the Assistant Secretary modifies or rescinds it.

(1) A value determination by MMS is not an appealable decision or order under 30 CFR part 290 subpart B.

(2) If you receive an order requiring you to pay royalty on the same basis as the value determination, you may appeal that order under 30 CFR part 290 subpart B.

(e) In making a value determination, MMS or the Assistant Secretary may use any of the applicable valuation criteria in this subpart.

(f) A change in an applicable statute or regulation on which any value determination is based takes precedence over the value determination, regardless of whether the MMS or the Assistant Secretary modifies or rescinds the value determination.

(g) The MMS or the Assistant Secretary generally will not retroactively modify or rescind a value determination issued under paragraph (d) of this section, unless:

(1) There was a misstatement or omission of material facts; or

(2) The facts subsequently developed are materially different from the facts on which the guidance was based.

(h) MMS may make requests and replies under this section available to the public, subject to the confidentiality requirements under §206.108.

#### **§ 206.108 Does MMS protect information I provide?**



Certain information you submit to MMS regarding valuation of oil, including transportation allowances, may be exempt from disclosure. To the extent applicable laws and regulations permit, MMS will keep confidential any data you submit that is privileged, confidential, or otherwise exempt from disclosure. All requests for information must be submitted under the Freedom of Information Act regulations of the Department of the Interior at 43 CFR part 2.

#### **§ 206.109 When may I take a transportation allowance in determining value?**



(a) *Transportation allowances permitted when value is based on gross proceeds.* MMS will allow a deduction for the reasonable, actual costs to transport oil from the lease to the point off the lease under §§206.110 or 206.111, as applicable. This paragraph applies when:

(1) You value oil under §206.102 based on gross proceeds from a sale at a point off the lease, unit, or communitized area where the oil is produced, and

(2) The movement to the sales point is not gathering.

(b) *Transportation allowances and other adjustments that apply when value is based on NYMEX prices or ANS spot prices.* If you value oil using NYMEX prices or ANS spot prices under §206.103, MMS will allow an adjustment for certain location and quality differentials and certain costs associated with transporting oil as provided under §206.112.

(c) *Limits on transportation allowances.* (1) Except as provided in paragraph (c)(2) of this section, your transportation allowance may not exceed 50 percent of the value of the oil as determined under §206.102 or §206.103 of this subpart. You may not use transportation costs incurred to move a particular volume of production to reduce royalties owed on production for which those costs were not incurred.

(2) You may ask MMS to approve a transportation allowance in excess of the limitation in paragraph (c) (1) of this section. You must demonstrate that the transportation costs incurred were reasonable, actual, and necessary. Your application for exception (using Form MMS-4393, Request to Exceed Regulatory

Allowance Limitation) must contain all relevant and supporting documentation necessary for MMS to make a determination. You may never reduce the royalty value of any production to zero.

(d) *Allocation of transportation costs.* You must allocate transportation costs among all products produced and transported as provided in §§206.110 and 206.111. You must express transportation allowances for oil as dollars per barrel.

(e) *Liability for additional payments.* If MMS determines that you took an excessive transportation allowance, then you must pay any additional royalties due, plus interest under 30 CFR 218.54. You also could be entitled to a credit with interest under applicable rules if you understated your transportation allowance. If you take a deduction for transportation on Form MMS-2014 by improperly netting the allowance against the sales value of the oil instead of reporting the allowance as a separate entry, MMS may assess you an amount under §206.116.

[65 FR 14088, Mar. 15, 2000, as amended at 69 FR 24976, May 5, 2004]

## **§ 206.110 How do I determine a transportation allowance under an arm's-length transportation contract?**



[top](#)

(a) If you or your affiliate incur transportation costs under an arm's-length transportation contract, you may claim a transportation allowance for the reasonable, actual costs incurred as more fully explained in paragraph (b) of this section, except as provided in paragraphs (a)(1) and (a)(2) of this section and subject to the limitation in §206.109(c). You must be able to demonstrate that your or your affiliate's contract is at arm's length. You do not need MMS approval before reporting a transportation allowance for costs incurred under an arm's-length transportation contract.

(1) If MMS determines that the contract reflects more than the consideration actually transferred either directly or indirectly from you or your affiliate to the transporter for the transportation, MMS may require that you calculate the transportation allowance under §206.111.

(2) You must calculate the transportation allowance under §206.111 if MMS determines that the consideration paid under an arm's-length transportation contract does not reflect the reasonable value of the transportation due to either:

(i) Misconduct by or between the parties to the arm's-length contract; or

(ii) Breach of your duty to market the oil for the mutual benefit of yourself and the lessor.

(A) MMS will not use this provision to simply substitute its judgment of the reasonable oil transportation costs incurred by you or your affiliate under an arm's-length transportation contract.

(B) The fact that the cost you or your affiliate incur in an arm's length transaction is higher than other measures of transportation costs, such as rates paid by others in the field or area, is insufficient to establish breach of the duty to market unless MMS finds additional evidence that you or your affiliate acted unreasonably or in bad faith in transporting oil from the lease.

(b) You may deduct any of the following actual costs you (including your affiliates) incur for transporting oil. You may not use as a deduction any cost that duplicates all or part of any other cost that you use under this paragraph.

(1) The amount that you pay under your arm's-length transportation contract or tariff.

(2) Fees paid (either in volume or in value) for actual or theoretical line losses.

(3) Fees paid for administration of a quality bank.

(4) The cost of carrying on your books as inventory a volume of oil that the pipeline operator requires you to maintain, and that you do maintain, in the line as line fill. You must calculate this cost as follows:

(i) Multiply the volume that the pipeline requires you to maintain, and that you do maintain, in the pipeline by the value of that volume for the current month calculated under §206.102 or §206.103, as applicable; and

(ii) Multiply the value calculated under paragraph (b)(4)(i) of this section by the monthly rate of return, calculated by dividing the rate of return specified in §206.111(i)(2) by 12.

(5) Fees paid to a terminal operator for loading and unloading of crude oil into or from a vessel, vehicle, pipeline, or other conveyance.

(6) Fees paid for short-term storage (30 days or less) incidental to transportation as required by a transporter.

(7) Fees paid to pump oil to another carrier's system or vehicles as required under a tariff.

(8) Transfer fees paid to a hub operator associated with physical movement of crude oil through the hub when you do not sell the oil at the hub. These fees do not include title transfer fees.

(9) Payments for a volumetric deduction to cover shrinkage when high-gravity petroleum (generally in excess of 51 degrees API) is mixed with lower-gravity crude oil for transportation.

(10) Costs of securing a letter of credit, or other surety, that the pipeline requires you as a shipper to maintain.

(c) You may not deduct any costs that are not actual costs of transporting oil, including but not limited to the following:

(1) Fees paid for long-term storage (more than 30 days).

(2) Administrative, handling, and accounting fees associated with terminalling.

(3) Title and terminal transfer fees.

(4) Fees paid to track and match receipts and deliveries at a market center or to avoid paying title transfer fees.

(5) Fees paid to brokers.

(6) Fees paid to a scheduling service provider.

(7) Internal costs, including salaries and related costs, rent/space costs, office equipment costs, legal fees, and other costs to schedule, nominate, and account for sale or movement of production.

(8) Gauging fees.

(d) If your arm's-length transportation contract includes more than one liquid product, and the transportation costs attributable to each product cannot be determined from the contract, then you must allocate the total transportation costs to each of the liquid products transported.

(1) Your allocation must use the same proportion as the ratio of the volume of each product (excluding waste products with no value) to the volume of all liquid products (excluding waste products with no value).

(2) You may not claim an allowance for the costs of transporting lease production that is not royalty-bearing.

(3) You may propose to MMS a cost allocation method on the basis of the values of the products transported. MMS will approve the method unless it is not consistent with the purposes of the regulations in this subpart.

(e) If your arm's-length transportation contract includes both gaseous and liquid products, and the transportation costs attributable to each product cannot be determined from the contract, then you must propose an allocation procedure to MMS.

(1) You may use your proposed procedure to calculate a transportation allowance until MMS accepts or rejects your cost allocation. If MMS rejects your cost allocation, you must amend your Form MMS-2014 for the months that you used the rejected method and pay any additional royalty and interest due.

(2) You must submit your initial proposal, including all available data, within 3 months after first claiming the allocated deductions on Form MMS-2014.

(f) If your payments for transportation under an arm's-length contract are not on a dollar-per-unit basis, you must convert whatever consideration is paid to a dollar-value equivalent.

(g) If your arm's-length sales contract includes a provision reducing the contract price by a transportation factor, do not separately report the transportation factor as a transportation allowance on Form MMS-2014.

(1) You may use the transportation factor in determining your gross proceeds for the sale of the product.

(2) You must obtain MMS approval before claiming a transportation factor in excess of 50 percent of the base price of the product.

[65 FR 14088, Mar. 15, 2000, as amended at 69 FR 24976, May 5, 2004]

**§ 206.111 How do I determine a transportation allowance if I do not have an arm's-length transportation contract or arm's-length tariff?**



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(a) This section applies if you or your affiliate do not have an arm's-length transportation contract, including situations where you or your affiliate provide your own transportation services. Calculate your transportation allowance based on your or your affiliate's reasonable, actual costs for transportation during the reporting period using the procedures prescribed in this section.

(b) Your or your affiliate's actual costs include the following:

(1) Operating and maintenance expenses under paragraphs (d) and (e) of this section;

(2) Overhead under paragraph (f) of this section;

(3) Depreciation under paragraphs (g) and (h) of this section;

(4) A return on undepreciated capital investment under paragraph (i) of this section; and

(5) Once the transportation system has been depreciated below ten percent of total capital investment, a return on ten percent of total capital investment under paragraph (j) of this section.

(6) To the extent not included in costs identified in paragraphs (d) through (j) of this section, you may also deduct the following actual costs. You may not use any cost as a deduction that duplicates all or part of any other cost that you use under this section:

(i) Volumetric adjustments for actual (not theoretical) line losses.

(ii) The cost of carrying on your books as inventory a volume of oil that the pipeline operator requires you as a shipper to maintain, and that you do maintain, in the line as line fill. You must calculate this cost as follows:

(A) Multiply the volume that the pipeline requires you to maintain, and that you do maintain, in the pipeline by the value of that volume for the current month calculated under §206.102 or §206.103, as applicable; and

(B) Multiply the value calculated under paragraph (b)(6)(ii)(A) of this section by the monthly rate of return, calculated by dividing the rate of return specified in §206.111(i)(2) by 12.

(iii) Fees paid to a non-affiliated terminal operator for loading and unloading of crude oil into or from a vessel, vehicle, pipeline, or other conveyance.

(iv) Transfer fees paid to a hub operator associated with physical movement of crude oil through the hub when you do not sell the oil at the hub. These fees do not include title transfer fees.

(v) A volumetric deduction to cover shrinkage when high-gravity petroleum (generally in excess of 51 degrees API) is mixed with lower-gravity crude oil for transportation.

(vi) Fees paid to a non-affiliated quality bank administrator for administration of a quality bank.

(7) You may not deduct any costs that are not actual costs of transporting oil, including but not limited to the following:

(i) Fees paid for long-term storage (more than 30 days).

(ii) Administrative, handling, and accounting fees associated with terminalling.

(iii) Title and terminal transfer fees.

(iv) Fees paid to track and match receipts and deliveries at a market center or to avoid paying title transfer fees.

(v) Fees paid to brokers.

(vi) Fees paid to a scheduling service provider.

(vii) Internal costs, including salaries and related costs, rent/space costs, office equipment costs, legal fees, and other costs to schedule, nominate, and account for sale or movement of production.

(viii) Theoretical line losses.

(ix) Gauging fees.

(c) Allowable capital costs are generally those for depreciable fixed assets (including costs of delivery and installation of capital equipment) which are an integral part of the transportation system.

(d) Allowable operating expenses include:

(i) Operations supervision and engineering;

(ii) Operations labor;

(iii) Fuel;

(iv) Utilities;

(v) Materials;

(vi) Ad valorem property taxes;

(vii) Rent;

(viii) Supplies; and

(ix) Any other directly allocable and attributable operating expense which you can document.

(e) Allowable maintenance expenses include:

(i) Maintenance of the transportation system;

(ii) Maintenance of equipment;

(iii) Maintenance labor; and

(iv) Other directly allocable and attributable maintenance expenses which you can document.

(f) Overhead directly attributable and allocable to the operation and maintenance of the transportation

system is an allowable expense. State and Federal income taxes and severance taxes and other fees, including royalties, are not allowable expenses.

(g) To compute depreciation, you may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves which the transportation system services, or a unit-of-production method. After you make an election, you may not change methods without MMS approval. You may not depreciate equipment below a reasonable salvage value.

(h) This paragraph describes the basis for your depreciation schedule.

(1) If you or your affiliate own a transportation system on June 1, 2000, you must base your depreciation schedule used in calculating actual transportation costs for production after June 1, 2000, on your total capital investment in the system (including your original purchase price or construction cost and subsequent reinvestment).

(2) If you or your affiliate purchased the transportation system at arm's length before June 1, 2000, you must incorporate depreciation on the schedule based on your purchase price (and subsequent reinvestment) into your transportation allowance calculations for production after June 1, 2000, beginning at the point on the depreciation schedule corresponding to that date. You must prorate your depreciation for calendar year 2000 by claiming part-year depreciation for the period from June 1, 2000 until December 31, 2000. You may not adjust your transportation costs for production before June 1, 2000, using the depreciation schedule based on your purchase price.

(3) If you are the original owner of the transportation system on June 1, 2000, or if you purchased your transportation system before March 1, 1988, you must continue to use your existing depreciation schedule in calculating actual transportation costs for production in periods after June 1, 2000.

(4) If you or your affiliate purchase a transportation system at arm's length from the original owner after June 1, 2000, you must base your depreciation schedule used in calculating actual transportation costs on your total capital investment in the system (including your original purchase price and subsequent reinvestment). You must prorate your depreciation for the year in which you or your affiliate purchased the system to reflect the portion of that year for which you or your affiliate own the system.

(5) If you or your affiliate purchase a transportation system at arm's length after June 1, 2000, from anyone other than the original owner, you must assume the depreciation schedule of the person from whom you bought the system. Include in the depreciation schedule any subsequent reinvestment.

(i)(1) To calculate a return on undepreciated capital investment, multiply the remaining undepreciated capital balance as of the beginning of the period for which you are calculating the transportation allowance by the rate of return provided in paragraph (i)(2) of this section.

(2) The rate of return is 1.3 times the industrial bond yield index for Standard & Poor's BBB bond rating. Use the monthly average rate published in "Standard & Poor's Bond Guide" for the first month of the reporting period for which the allowance applies. Calculate the rate at the beginning of each subsequent transportation allowance reporting period.

(j)(1) After a transportation system has been depreciated at or below a value equal to ten percent of your total capital investment, you may continue to include in the allowance calculation a cost equal to ten percent of your total capital investment in the transportation system multiplied by a rate of return under paragraph (i)(2) of this section.

(2) You may apply this paragraph to a transportation system that before June 1, 2000, was depreciated at or below a value equal to ten percent of your total capital investment.

(k) Calculate the deduction for transportation costs based on your or your affiliate's cost of transporting each product through each individual transportation system. Where more than one liquid product is transported, allocate costs consistently and equitably to each of the liquid products transported. Your allocation must use the same proportion as the ratio of the volume of each liquid product (excluding waste products with no value) to the volume of all liquid products (excluding waste products with no value).

(1) You may not take an allowance for transporting lease production that is not royalty-bearing.

(2) You may propose to MMS a cost allocation method on the basis of the values of the products transported. MMS will approve the method if it is consistent with the purposes of the regulations in this subpart.

- (1)(1) Where you transport both gaseous and liquid products through the same transportation system, you must propose a cost allocation procedure to MMS.
- (2) You may use your proposed procedure to calculate a transportation allowance until MMS accepts or rejects your cost allocation. If MMS rejects your cost allocation, you must amend your Form MMS-2014 for the months that you used the rejected method and pay any additional royalty and interest due.
- (3) You must submit your initial proposal, including all available data, within 3 months after first claiming the allocated deductions on Form MMS-2014.

[65 FR 14088, Mar. 15, 2000, as amended at 69 FR 24977, May 5, 2004]

**§ 206.112 What adjustments and transportation allowances apply when I value oil production from my lease using NYMEX prices or ANS spot prices?**



This section applies when you use NYMEX prices or ANS spot prices to calculate the value of production under §206.103. As specified in this section, adjust the NYMEX price to reflect the difference in value between your lease and Cushing, Oklahoma, or adjust the ANS spot price to reflect the difference in value between your lease and the appropriate MMS-recognized market center at which the ANS spot price is published (for example, Long Beach, California, or San Francisco, California). Paragraph (a) of this section explains how you adjust the value between the lease and the market center, and paragraph (b) of this section explains how you adjust the value between the market center and Cushing when you use NYMEX prices. Paragraph (c) of this section explains how adjustments may be made for quality differentials that are not accounted for through exchange agreements. Paragraph (d) of this section gives some examples. References in this section to "you" include your affiliates as applicable.

(a) To adjust the value between the lease and the market center:

- (1)(i) For oil that you exchange at arm's length between your lease and the market center (or between any intermediate points between those locations), you must calculate a lease-to-market center differential by the applicable location and quality differentials derived from your arm's-length exchange agreement applicable to production during the production month.
- (ii) For oil that you exchange between your lease and the market center (or between any intermediate points between those locations) under an exchange agreement that is not at arm's length, you must obtain approval from MMS for a location and quality differential. Until you obtain such approval, you may use the location and quality differential derived from that exchange agreement applicable to production during the production month. If MMS prescribes a different differential, you must apply MMS's differential to all periods for which you used your proposed differential. You must pay any additional royalties owed resulting from using MMS's differential plus late payment interest from the original royalty due date, or you may report a credit for any overpaid royalties plus interest under 30 U.S.C. 1721(h).
- (2) For oil that you transport between your lease and the market center (or between any intermediate points between those locations), you may take an allowance for the cost of transporting that oil between the relevant points as determined under §206.110 or §206.111, as applicable.
- (3) If you transport or exchange at arm's length (or both transport and exchange) at least 20 percent, but not all, of your oil produced from the lease to a market center, determine the adjustment between the lease and the market center for the oil that is not transported or exchanged (or both transported and exchanged) to or through a market center as follows:
- (i) Determine the volume-weighted average of the lease-to-market center adjustment calculated under paragraphs (a)(1) and (a)(2) of this section for the oil that you do transport or exchange (or both transport and exchange) from your lease to a market center.
- (ii) Use that volume-weighted average lease-to-market center adjustment as the adjustment for the oil that you do not transport or exchange (or both transport and exchange) from your lease to a market center.
- (4) If you transport or exchange (or both transport and exchange) less than 20 percent of the crude oil produced from your lease between the lease and a market center, you must propose to MMS an adjustment between the lease and the market center for the portion of the oil that you do not transport or exchange (or both transport and exchange) to a market center. Until you obtain such approval, you may use your proposed adjustment. If MMS prescribes a different adjustment, you must apply MMS's

adjustment to all periods for which you used your proposed adjustment. You must pay any additional royalties owed resulting from using MMS's adjustment plus late payment interest from the original royalty due date, or you may report a credit for any overpaid royalties plus interest under 30 U.S.C. 1721(h).

(5) You may not both take a transportation allowance and use a location and quality adjustment or exchange differential for the same oil between the same points.

(b) For oil that you value using NYMEX prices, adjust the value between the market center and Cushing, Oklahoma, as follows:

(1) If you have arm's-length exchange agreements between the market center and Cushing under which you exchange to Cushing at least 20 percent of all the oil you own at the market center during the production month, you must use the volume-weighted average of the location and quality differentials from those agreements as the adjustment between the market center and Cushing for all the oil that you produce from the leases during that production month for which that market center is used.

(2) If paragraph (b)(1) of this section does not apply, you must use the WTI differential published in an MMS-approved publication for the market center nearest your lease, for crude oil most similar in quality to your production, as the adjustment between the market center and Cushing. (For example, for light sweet crude oil produced offshore of Louisiana, use the WTI differential for Light Louisiana Sweet crude oil at St. James, Louisiana.) After you select an MMS-approved publication, you may not select a different publication more often than once every 2 years, unless the publication you use is no longer published or MMS revokes its approval of the publication. If you are required to change publications, you must begin a new 2-year period.

(3) If neither paragraph (b)(1) nor (b)(2) of this section applies, you may propose an alternative differential to MMS. Until you obtain such approval, you may use your proposed differential. If MMS prescribes a different differential, you must apply MMS's differential to all periods for which you used your proposed differential. You must pay any additional royalties owed resulting from using MMS's differential plus late payment interest from the original royalty due date, or you may report a credit for any overpaid royalties plus interest under 30 U.S.C. 1721(h).

(c)(1) If you adjust for location and quality differentials or for transportation costs under paragraphs (a) and (b) of this section, also adjust the NYMEX price or ANS spot price for quality based on premiums or penalties determined by pipeline quality bank specifications at intermediate commingling points or at the market center if those points are downstream of the royalty measurement point approved by MMS or BLM, as applicable. Make this adjustment only if and to the extent that such adjustments were not already included in the location and quality differentials determined from your arm's-length exchange agreements.

(2) If the quality of your oil as adjusted is still different from the quality of the representative crude oil at the market center after making the quality adjustments described in paragraphs (a), (b) and (c)(1) of this section, you may make further gravity adjustments using posted price gravity tables. If quality bank adjustments do not incorporate or provide for adjustments for sulfur content, you may make sulfur adjustments, based on the quality of the representative crude oil at the market center, of 5.0 cents per one-tenth percent difference in sulfur content, unless MMS approves a higher adjustment.

(d) The examples in this paragraph illustrate how to apply the requirement of this section.

(1) *Example.* Assume that a Federal lessee produces crude oil from a lease near Artesia, New Mexico. Further, assume that the lessee transports the oil to Roswell, New Mexico, and then exchanges the oil to Midland, Texas. Assume the lessee refines the oil received in exchange at Midland. Assume that the NYMEX price is \$30.00/bbl, adjusted for the roll; that the WTI differential (Cushing to Midland) is  $-\$.10/\text{bbl}$ ; that the lessee's exchange agreement between Roswell and Midland results in a location and quality differential of  $-\$.08/\text{bbl}$ ; and that the lessee's actual cost of transporting the oil from Artesia to Roswell is  $\$.40/\text{bbl}$ . In this example, the royalty value of the oil is  $\$30.00 - \$.10 - \$.08 - \$.40 = \$29.42/\text{bbl}$ .

(2) *Example.* Assume the same facts as in the example in paragraph (1), except that the lessee transports and exchanges to Midland 40 percent of the production from the lease near Artesia, and transports the remaining 60 percent directly to its own refinery in Ohio. In this example, the 40 percent of the production would be valued at  $\$29.42/\text{bbl}$ , as explained in the previous example. In this example, the other 60 percent also would be valued at  $\$29.42/\text{bbl}$ .

(3) *Example.* Assume that a Federal lessee produces crude oil from a lease near Bakersfield, California. Further, assume that the lessee transports the oil to Hynes Station, and then exchanges the oil to Cushing which it further exchanges with oil it refines. Assume that the ANS spot price is  $\$20.00/\text{bbl}$ , and that the lessee's actual cost of transporting the oil from Bakersfield to Hynes Station is  $\$.28/\text{bbl}$ . The lessee must request approval from MMS for a location and quality adjustment between Hynes Station and Long Beach. For example, the lessee likely would propose using the tariff on Line 63 from Hynes

Station to Long Beach as the adjustment between those points. Assume that adjustment to be \$.72, including the sulfur and gravity bank adjustments, and that MMS approves the lessee's request. In this example, the preliminary (because the location and quality adjustment is subject to MMS review) royalty value of the oil is  $\$20.00 - \$.72 - \$.28 = \$19.00/\text{bbl}$ . The fact that oil was exchanged to Cushing does not change use of ANS spot prices for royalty valuation.

[69 FR 24978, May 5, 2004]

#### **§ 206.113 How will MMS identify market centers?**



[top](#)

MMS periodically will publish in the Federal Register a list of market centers. MMS will monitor market activity and, if necessary, add to or modify the list of market centers and will publish such modifications in the Federal Register. MMS will consider the following factors and conditions in specifying market centers:

- (a) Points where MMS-approved publications publish prices useful for index purposes;
- (b) Markets served;
- (c) Input from industry and others knowledgeable in crude oil marketing and transportation;
- (d) Simplification; and
- (e) Other relevant matters.

#### **§ 206.114 What are my reporting requirements under an arm's-length transportation contract?**



[top](#)

You or your affiliate must use a separate entry on Form MMS-2014 to notify MMS of an allowance based on transportation costs you or your affiliate incur. MMS may require you or your affiliate to submit arm's-length transportation contracts, production agreements, operating agreements, and related documents. Recordkeeping requirements are found at part 207 of this chapter.

#### **§ 206.115 What are my reporting requirements under a non-arm's-length transportation arrangement?**



[top](#)

- (a) You or your affiliate must use a separate entry on Form MMS-2014 to notify MMS of an allowance based on transportation costs you or your affiliate incur.
- (b) For new transportation facilities or arrangements, base your initial deduction on estimates of allowable oil transportation costs for the applicable period. Use the most recently available operations data for the transportation system or, if such data are not available, use estimates based on data for similar transportation systems. Section 206.117 will apply when you amend your report based on your actual costs.
- (c) MMS may require you or your affiliate to submit all data used to calculate the allowance deduction. Recordkeeping requirements are found at part 207 of this chapter.

#### **§ 206.116 What interest applies if I improperly report a transportation allowance?**



[top](#)

- (a) If you or your affiliate deducts a transportation allowance on Form MMS-2014 that exceeds 50 percent of the value of the oil transported without obtaining MMS's prior approval under §206.109, you must pay interest on the excess allowance amount taken from the date that amount is taken to the date you or your affiliate files an exception request that MMS approves. If you do not file an exception

request, or if MMS does not approve your request, you must pay interest on the excess allowance amount taken from the date that amount is taken until the date you pay the additional royalties owed.

(b) If you or your affiliate takes a deduction for transportation on Form MMS-2014 by improperly netting an allowance against the oil instead of reporting the allowance as a separate entry, MMS may assess a civil penalty under 30 CFR part 241.

[73 FR 15890, Mar. 26, 2008]

#### **§ 206.117 What reporting adjustments must I make for transportation allowances?**



[top](#)

(a) If your or your affiliate's actual transportation allowance is less than the amount you claimed on Form MMS-2014 for each month during the allowance reporting period, you must pay additional royalties plus interest computed under 30 CFR 218.54 from the date you took the deduction to the date you repay the difference.

(b) If the actual transportation allowance is greater than the amount you claimed on Form MMS-2014 for any month during the allowance form reporting period, you are entitled to a credit plus interest under applicable rules.

#### **§ 206.119 How are royalty quantity and quality determined?**



[top](#)

(a) Compute royalties based on the quantity and quality of oil as measured at the point of settlement approved by BLM for onshore leases or MMS for offshore leases.

(b) If the value of oil determined under this subpart is based upon a quantity or quality different from the quantity or quality at the point of royalty settlement approved by the BLM for onshore leases or MMS for offshore leases, adjust the value for those differences in quantity or quality.

(c) Any actual loss that you may incur before the royalty settlement metering or measurement point is not subject to royalty if BLM or MMS, as appropriate, determines that the loss is unavoidable.

(d) Except as provided in paragraph (b) of this section, royalties are due on 100 percent of the volume measured at the approved point of royalty settlement. You may not claim a reduction in that measured volume for actual losses beyond the approved point of royalty settlement or for theoretical losses that are claimed to have taken place either before or after the approved point of royalty settlement.

[65 FR 14088, Mar. 15, 2000, as amended at 69 FR 24979, May 5, 2004]

#### **§ 206.120 How are operating allowances determined?**



[top](#)

MMS may use an operating allowance for the purpose of computing payment obligations when specified in the notice of sale and the lease. MMS will specify the allowance amount or formula in the notice of sale and in the lease agreement.

#### **Subpart D—Federal Gas**



[top](#)

**Source:** 53 FR 1272, Jan. 15, 1988, unless otherwise noted.

#### **§ 206.150 Purpose and scope.**



[top](#)

(a) This subpart is applicable to all gas production from Federal oil and gas leases. The purpose of this subpart is to establish the value of production for royalty purposes consistent with the mineral leasing laws, other applicable laws and lease terms.

(b) If the regulations in this subpart are inconsistent with:

(1) A Federal statute;

(2) A settlement agreement between the United States and a lessee resulting from administrative or judicial litigation;

(3) A written agreement between the lessee and the MMS Director establishing a method to determine the value of production from any lease that MMS expects at least would approximate the value established under this subpart; or

(4) An express provision of an oil and gas lease subject to this subpart; then the statute, settlement agreement, written agreement, or lease provision will govern to the extent of the inconsistency.

(c) All royalty payments made to MMS are subject to audit and adjustment.

(d) The regulations in this subpart are intended to ensure that the administration of oil and gas leases is discharged in accordance with the requirements of the governing mineral leasing laws and lease terms.

[61 FR 5464, Feb. 12, 1996, as amended at 70 FR 11877, Mar. 10, 2005]

## § 206.151 Definitions.



[top](#)

For purposes of this subpart:

*Affiliate* means a person who controls, is controlled by, or is under common control with another person. For purposes of this subpart:

(1) Ownership or common ownership of more than 50 percent of the voting securities, or instruments of ownership, or other forms of ownership, of another person constitutes control. Ownership of less than 10 percent constitutes a presumption of noncontrol that MMS may rebut.

(2) If there is ownership or common ownership of 10 through 50 percent of the voting securities or instruments of ownership, or other forms of ownership, of another person, MMS will consider the following factors in determining whether there is control under the circumstances of a particular case:

(i) The extent to which there are common officers or directors;

(ii) With respect to the voting securities, or instruments of ownership, or other forms of ownership: The percentage of ownership or common ownership, the relative percentage of ownership or common ownership compared to the percentage(s) of ownership by other persons, whether a person is the greatest single owner, or whether there is an opposing voting bloc of greater ownership;

(iii) Operation of a lease, plant, pipeline, or other facility;

(iv) The extent of participation by other owners in operations and day-to-day management of a lease, plant, pipeline, or other facility; and

(v) Other evidence of power to exercise control over or common control with another person.

(3) Regardless of any percentage of ownership or common ownership, relatives, either by blood or marriage, are affiliates.

*Allowance* means a deduction in determining value for royalty purposes. *Processing allowance* means an allowance for the reasonable, actual costs of processing gas determined under this subpart. *Transportation allowance* means an allowance for the reasonable, actual costs of moving unprocessed gas, residue gas, or gas plant products to a point of sale or delivery off the lease, unit area, or communitized area, or away from a processing plant. The transportation allowance does not include

gathering costs.

*Area* means a geographic region at least as large as the defined limits of an oil and/or gas field, in which oil and/or gas lease products have similar quality, economic, and legal characteristics.

*Arm's-length contract* means a contract or agreement between independent persons who are not affiliates and who have opposing economic interests regarding that contract. To be considered arm's length for any production month, a contract must satisfy this definition for that month, as well as when the contract was executed.

*Audit* means a review, conducted in accordance with generally accepted accounting and auditing standards, of royalty payment compliance activities of lessees or other interest holders who pay royalties, rents, or bonuses on Federal leases.

*BLM* means the Bureau of Land Management of the Department of the Interior.

*Compression* means the process of raising the pressure of gas.

*Condensate* means liquid hydrocarbons (normally exceeding 40 degrees of API gravity) recovered at the surface without resorting to processing. Condensate is the mixture of liquid hydrocarbons that results from condensation of petroleum hydrocarbons existing initially in a gaseous phase in an underground reservoir.

*Contract* means any oral or written agreement, including amendments or revisions thereto, between two or more persons and enforceable by law that with due consideration creates an obligation.

*Field* means a geographic region situated over one or more subsurface oil and gas reservoirs encompassing at least the outermost boundaries of all oil and gas accumulations known to be within those reservoirs vertically projected to the land surface. Onshore fields are usually given names and their official boundaries are often designated by oil and gas regulatory agencies in the respective States in which the fields are located. Outer Continental Shelf (OCS) fields are named and their boundaries are designated by MMS.

*Gas* means any fluid, either combustible or noncombustible, hydrocarbon or nonhydrocarbon, which is extracted from a reservoir and which has neither independent shape nor volume, but tends to expand indefinitely. It is a substance that exists in a gaseous or rarefied state under standard temperature and pressure conditions.

*Gas plant products* means separate marketable elements, compounds, or mixtures, whether in liquid, gaseous, or solid form, resulting from processing gas, excluding residue gas.

*Gathering* means the movement of lease production to a central accumulation and/or treatment point on the lease, unit or communitized area, or to a central accumulation or treatment point off the lease, unit or communitized area as approved by BLM or MMS OCS operations personnel for onshore and OCS leases, respectively.

*Gross proceeds* (for royalty payment purposes) means the total monies and other consideration accruing to an oil and gas lessee for the disposition of the gas, residue gas, and gas plant products produced. Gross proceeds includes, but is not limited to, payments to the lessee for certain services such as dehydration, measurement, and/or gathering to the extent that the lessee is obligated to perform them at no cost to the Federal Government. Tax reimbursements are part of the gross proceeds accruing to a lessee even though the Federal royalty interest may be exempt from taxation. Monies and other consideration, including the forms of consideration identified in this paragraph, to which a lessee is contractually or legally entitled but which it does not seek to collect through reasonable efforts are also part of gross proceeds.

*Lease* means any 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 lease products—or the land area covered by that authorization, whichever is required by the context.

*Lease products* means any leased minerals attributable to, originating from, or allocated to Outer Continental Shelf or onshore Federal leases.

*Lessee* means any person to whom the United States issues a lease, and any person who has been assigned an obligation to make royalty or other payments required by the lease. This includes any person who has an interest in a lease as well as an operator or payor who has no interest in the lease

but who has assumed the royalty payment responsibility.

*Like-quality lease products* means lease products which have similar chemical, physical, and legal characteristics.

*Marketable condition* means lease products which are sufficiently free from impurities and otherwise in a condition that they will be accepted by a purchaser under a sales contract typical for the field or area.

*Marketing affiliate* means an affiliate of the lessee whose function is to acquire only the lessee's production and to market that production.

*Minimum royalty* means that minimum amount of annual royalty that the lessee must pay as specified in the lease or in applicable leasing regulations.

*Net-back method* (or work-back method) means a method for calculating market value of gas at the lease. Under this method, costs of transportation, processing, or manufacturing are deducted from the proceeds received for the gas, residue gas or gas plant products, and any extracted, processed, or manufactured products, or from the value of the gas, residue gas or gas plant products, and any extracted, processed, or manufactured products, at the first point at which reasonable values for any such products may be determined by a sale pursuant to an arm's-length contract or comparison to other sales of such products, to ascertain value at the lease.

*Net output* means the quantity of residue gas and each gas plant product that a processing plant produces.

*Net profit share* (for applicable Federal leases) means the specified share of the net profit from production of oil and gas as provided in the agreement.

*Netting* means the deduction of an allowance from the sales value by reporting a net sales value, instead of correctly reporting the deduction as a separate entry on Form MMS-2014.

*Outer Continental Shelf (OCS)* means all submerged lands lying seaward and outside of the area of land beneath navigable waters as defined in section 2 of the Submerged Lands Act (43 U.S.C. 1301) and of which the subsoil and seabed appertain to the United States and are subject to its jurisdiction and control.

*Person* means any individual, firm, corporation, association, partnership, consortium, or joint venture (when established as a separate entity).

*Posted price* means the price, net of all adjustments for quality and location, specified in publicly available price bulletins or other price notices available as part of normal business operations for quantities of unprocessed gas, residue gas, or gas plant products in marketable condition.

*Processing* means any process designed to remove elements or compounds (hydrocarbon and nonhydrocarbon) from gas, including absorption, adsorption, or refrigeration. Field processes which 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.

*Residue gas* means that hydrocarbon gas consisting principally of methane resulting from processing gas.

*Sales type code* means the contract type or general disposition (e.g., arm's-length or non-arm's-length) of production from the lease. The sales type code applies to the sales contract, or other disposition, and not to the arm's-length or non-arm's-length nature of a transportation or processing allowance.

*Section 6 lease* means an OCS lease subject to section 6 of the Outer Continental Shelf Lands Act, as amended, 43 U.S.C. 1335.

*Spot sales agreement* means a contract wherein a seller agrees to sell to a buyer a specified amount of unprocessed gas, residue gas, or gas plant products at a specified price over a fixed period, usually of short duration, which does not normally require a cancellation notice to terminate, and which does not contain an obligation, nor imply an intent, to continue in subsequent periods.

*Warranty contract* means a long-term contract entered into prior to 1970, including any amendments thereto, for the sale of gas wherein the producer agrees to sell a specific amount of gas and the gas

delivered in satisfaction of this obligation may come from fields or sources outside of the designated fields.

[53 FR 1272, Jan. 15, 1988, as amended at 53 FR 45084, Nov. 8, 1988; 61 FR 5464, Feb. 12, 1996; 64 FR 43288, Aug. 10, 1999; 70 FR 11878, Mar. 10, 2005; 73 FR 15890, Mar. 26, 2008]

#### § 206.152 Valuation standards—unprocessed gas.



[top](#)

(a)(1) This section applies to the valuation of all gas that is not processed and all gas that is processed but is sold or otherwise disposed of by the lessee pursuant to an arm's-length contract prior to processing (including all gas where the lessee's arm's-length contract for the sale of that gas prior to processing provides for the value to be determined on the basis of a percentage of the purchaser's proceeds resulting from processing the gas). This section also applies to processed gas that must be valued prior to processing in accordance with §206.155 of this part. Where the lessee's contract includes a reservation of the right to process the gas and the lessee exercises that right, §206.153 of this part shall apply instead of this section.

(2) The value of production, for royalty purposes, of gas subject to this subpart shall be the value of gas determined under this section less applicable allowances.

(b)(1)(i) The value of gas sold under an arm's-length contract is the gross proceeds accruing to the lessee except as provided in paragraphs (b)(1)(ii), (iii), and (iv) of this section. The lessee shall have the burden of demonstrating that its contract is arm's-length. The value which the lessee reports, for royalty purposes, is subject to monitoring, review, and audit. For purposes of this section, gas which is sold or otherwise transferred to the lessee's marketing affiliate and then sold by the marketing affiliate pursuant to an arm's-length contract shall be valued in accordance with this paragraph based upon the sale by the marketing affiliate. Also, 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, the value of production, for royalty purposes, shall never be less than a value equivalent to 100 percent of the value of the residue gas attributable to the processing of the lessee's gas.

(ii) In conducting reviews and audits, MMS will examine whether the contract reflects the total consideration actually transferred either directly or indirectly from the buyer to the seller for the gas. If the contract does not reflect the total consideration, then the MMS may require that the gas sold pursuant to that contract be valued in accordance with paragraph (c) of this section. Value may not be less than the gross proceeds accruing to the lessee, including the additional consideration.

(iii) If the MMS determines that the gross proceeds accruing to the lessee pursuant to an arm's-length contract do not reflect the reasonable value of the production because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then MMS shall require that the gas production be valued pursuant to paragraph (c)(2) or (c)(3) of this section, and in accordance with the notification requirements of paragraph (e) of this section. When MMS determines that the value may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's value.

(iv) *How to value over-delivered volumes under a cash-out program.* This paragraph applies to situations where a pipeline purchases gas from a lessee according to a cash-out program under a transportation contract. For all over-delivered volumes, the royalty value is the price the pipeline is required to pay for volumes within the tolerances for over-delivery specified in the transportation contract. Use the same value for volumes that exceed the over-delivery tolerances even if those volumes are subject to a lower price under the transportation contract. However, if MMS determines that the price specified in the transportation contract for over-delivered volumes is unreasonably low, the lessee must value all over-delivered volumes under paragraph (c)(2) or (c)(3) of this section.

(2) Notwithstanding the provisions of paragraph (b)(1) of this section, the value of gas sold pursuant to a warranty contract shall be determined by MMS, and due consideration will be given to all valuation criteria specified in this section. The lessee must request a value determination in accordance with paragraph (g) of this section for gas sold pursuant to a warranty contract; provided, however, that any value determination for a warranty contract in effect on the effective date of these regulations shall remain in effect until modified by MMS.

(3) MMS may require a lessee to certify that its arm's-length contract provisions include all of the consideration to be paid by the buyer, either directly or indirectly, for the gas.

(c) The value of gas subject to this section which is not sold pursuant to an arm's-length contract shall be the reasonable value determined in accordance with the first applicable of the following methods:

(1) The gross proceeds accruing to the lessee pursuant to a sale under its non-arm's-length contract (or other disposition other than by an arm's-length contract), provided that those gross proceeds are equivalent to the gross proceeds derived from, or paid under, comparable arm's-length contracts for purchases, sales, or other dispositions of like-quality gas in the same field (or, if necessary to obtain a reasonable sample, from the same area). In evaluating the comparability of arm's-length contracts for the purposes of these regulations, the following factors shall be considered: price, time of execution, duration, market or markets served, terms, quality of gas, volume, and such other factors as may be appropriate to reflect the value of the gas;

(2) A value determined by consideration of other information relevant in valuing like-quality gas, including gross proceeds under arm's-length contracts for like-quality gas in the same field or nearby fields or areas, posted prices for gas, prices received in arm's-length spot sales of gas, other reliable public sources of price or market information, and other information as to the particular lease operation or the saleability of the gas; or

(3) A net-back method or any other reasonable method to determine value.

(d)(1) Notwithstanding any other provisions of this section, except paragraph (h) of this section, if the maximum price permitted by Federal law at which gas may be sold is less than the value determined pursuant to this section, then MMS shall accept such maximum price as the value. For purposes of this section, price limitations set by any State or local government shall not be considered as a maximum price permitted by Federal law.

(2) The limitation prescribed in paragraph (d)(1) of this section shall not apply to gas sold pursuant to a warranty contract and valued pursuant to paragraph (b)(2) of this section.

(e)(1) Where the value is determined pursuant to paragraph (c) of this section, the lessee shall retain all data relevant to the determination of royalty value. Such data shall be subject to review and audit, and MMS will direct a lessee to use a different value if it determines that the reported value is inconsistent with the requirements of these regulations.

(2) Any Federal lessee will make available upon request to the authorized MMS or State representatives, to the Office of the Inspector General of the Department of the Interior, or other person authorized to receive such information, arm's-length sales and volume data for like-quality production sold, purchased or otherwise obtained by the lessee from the field or area or from nearby fields or areas.

(3) A lessee shall notify MMS if it has determined value pursuant to paragraph (c)(2) or (c)(3) of this section. The notification shall be by letter to the MMS Associate Director for Minerals Revenue Management or his/her designee. The letter shall identify the valuation method to be used and contain a brief description of the procedure to be followed. The notification required by this paragraph is a one-time notification due no later than the end of the month following the month the lessee first reports royalties on a Form MMS-2014 using a valuation method authorized by paragraph (c)(2) or (c)(3) of this section, and each time there is a change in a method under paragraph (c)(2) or (c)(3) of this section.

(f) If MMS determines that a lessee has not properly determined value, the lessee shall pay the difference, if any, between royalty payments made based upon the value it has used and the royalty payments that are due based upon the value established by MMS. The lessee shall also pay interest on that difference computed pursuant to 30 CFR 218.54. If the lessee is entitled to a credit, MMS will provide instructions for the taking of that credit.

(g) The lessee may request a value determination from MMS. In that event, the lessee shall propose to MMS a value determination method, and may use that method in determining value for royalty purposes until MMS issues its decision. The lessee shall submit all available data relevant to its proposal. The MMS shall expeditiously determine the value based upon the lessee's proposal and any additional information MMS deems necessary. In making a value determination MMS may use any of the valuation criteria authorized by this subpart. That determination shall remain effective for the period stated therein. After MMS issues its determination, the lessee shall make the adjustments in accordance with paragraph (f) of this section.

(h) Notwithstanding any other provision of this section, under no circumstances shall the value of production for royalty purposes be less than the gross proceeds accruing to the lessee for lease production, less applicable allowances.

(i) The lessee must place gas in marketable condition and market the gas for the mutual benefit of the lessee and the lessor at no cost to the Federal Government. Where the value established under this

section is determined by a lessee's gross proceeds, that value will be increased to the extent that the gross proceeds have been reduced because the purchaser, or any other person, is providing certain services the cost of which ordinarily is the responsibility of the lessee to place the gas in marketable condition or to market the gas.

(j) Value shall be based on the highest price a prudent lessee can receive through legally enforceable claims under its contract. If there is no contract revision or amendment, and the lessee fails to take proper or timely action to receive prices or benefits to which it is entitled, it must pay royalty at a value based upon that obtainable price or benefit. Contract revisions or amendments shall be in writing and signed by all parties to an arm's-length contract. If the lessee makes timely application for a price increase or benefit allowed under its contract but the purchaser refuses, and the lessee takes reasonable measures, which are documented, to force purchaser compliance, the lessee will owe no additional royalties unless or until monies or consideration resulting from the price increase or additional benefits are received. This paragraph shall not be construed to permit a lessee to avoid its royalty payment obligation in situations where a purchaser fails to pay, in whole or in part or timely, for a quantity of gas.

(k) Notwithstanding any provision in these regulations to the contrary, no review, reconciliation, monitoring, or other like process that results in a redetermination by MMS of value under this section shall be considered final or binding as against the Federal Government or its beneficiaries until the audit period is formally closed.

(l) Certain information submitted to MMS to support valuation proposals, including transportation or extraordinary cost allowances, is exempted from disclosure by the Freedom of Information Act, 5 U.S.C. §552, or other Federal law. Any data specified by law to be privileged, confidential, or otherwise exempt will be maintained in a confidential manner in accordance with applicable law and regulations. All requests for information about determinations made under this subpart are to be submitted in accordance with the Freedom of Information Act regulation of the Department of the Interior, 43 CFR part 2.

[53 FR 1272, Jan. 15, 1988, as amended at 56 FR 46530, Sept. 13, 1991; 61 FR 5464, Feb. 12, 1996; 62 FR 65761, 65762, Dec. 16, 1997]

#### **§ 206.153 Valuation standards—processed gas.**



[top](#)

(a)(1) This section applies to the valuation of all gas that is processed by the lessee and any other gas production to which this subpart applies and that is not subject to the valuation provisions of §206.152 of this part. This section applies where the lessee's contract includes a reservation of the right to process the gas and the lessee exercises that right.

(2) The value of production, for royalty purposes, of gas subject to this section shall be the combined value of the residue gas and all gas plant products determined pursuant to this section, plus the value of any condensate recovered downstream of the point of royalty settlement without resorting to processing determined pursuant to §206.102 of this part, less applicable transportation allowances and processing allowances determined pursuant to this subpart.

(b)(1)(i) The value of residue gas or any gas plant product sold under an arm's-length contract is the gross proceeds accruing to the lessee, except as provided in paragraphs (b)(1)(ii), (iii), and (iv) of this section. The lessee shall have the burden of demonstrating that its contract is arm's-length. The value that the lessee reports for royalty purposes is subject to monitoring, review, and audit. For purposes of this section, residue gas or any gas plant product which is sold or otherwise transferred to the lessee's marketing affiliate and then sold by the marketing affiliate pursuant to an arm's-length contract shall be valued in accordance with this paragraph based upon the sale by the marketing affiliate.

(ii) In conducting these reviews and audits, MMS will examine whether or not the contract reflects the total consideration actually transferred either directly or indirectly from the buyer to the seller for the residue gas or gas plant product. If the contract does not reflect the total consideration, then the MMS may require that the residue gas or gas plant product sold pursuant to that contract be valued in accordance with paragraph (c) of this section. Value may not be less than the gross proceeds accruing to the lessee, including the additional consideration.

(iii) If the MMS determines that the gross proceeds accruing to the lessee pursuant to an arm's-length contract do not reflect the reasonable value of the residue gas or gas plant product because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then MMS shall require that the residue gas or gas plant product be valued pursuant to paragraph (c)(2) or (c)(3) of

this section, and in accordance with the notification requirements of paragraph (e) of this section. When MMS determines that the value may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's value.

(iv) *How to value over-delivered volumes under a cash-out program.* This paragraph applies to situations where a pipeline purchases gas from a lessee according to a cash-out program under a transportation contract. For all over-delivered volumes, the royalty value is the price the pipeline is required to pay for volumes within the tolerances for over-delivery specified in the transportation contract. Use the same value for volumes that exceed the over-delivery tolerances even if those volumes are subject to a lower price under the transportation contract. However, if MMS determines that the price specified in the transportation contract for over-delivered volumes is unreasonably low, the lessee must value all over-delivered volumes under paragraph (c)(2) or (c)(3) of this section.

(2) Notwithstanding the provisions of paragraph (b)(1) of this section, the value of residue gas sold pursuant to a warranty contract shall be determined by MMS, and due consideration will be given to all valuation criteria specified in this section. The lessee must request a value determination in accordance with paragraph (g) of this section for gas sold pursuant to a warranty contract; provided, however, that any value determination for a warranty contract in effect on the effective date of these regulations shall remain in effect until modified by MMS.

(3) MMS may require a lessee to certify that its arm's-length contract provisions include all of the consideration to be paid by the buyer, either directly or indirectly, for the residue gas or gas plant product.

(c) The value of residue gas or any gas plant product which is not sold pursuant to an arm's-length contract shall be the reasonable value determined in accordance with the first applicable of the following methods:

(1) The gross proceeds accruing to the lessee pursuant to a sale under its non-arm's-length contract (or other disposition other than by an arm's-length contract), provided that those gross proceeds are equivalent to the gross proceeds derived from, or paid under, comparable arm's-length contracts for purchases, sales, or other dispositions of like quality residue gas or gas plant products from the same processing plant (or, if necessary to obtain a reasonable sample, from nearby plants). In evaluating the comparability of arm's-length contracts for the purposes of these regulations, the following factors shall be considered: price, time of execution, duration, market or markets served, terms, quality of residue gas or gas plant products, volume, and such other factors as may be appropriate to reflect the value of the residue gas or gas plant products;

(2) A value determined by consideration of other information relevant in valuing like-quality residue gas or gas plant products, including gross proceeds under arm's-length contracts for like-quality residue gas or gas plant products from the same gas plant or other nearby processing plants, posted prices for residue gas or gas plant products, prices received in spot sales of residue gas or gas plant products, other reliable public sources of price or market information, and other information as to the particular lease operation or the saleability of such residue gas or gas plant products; or

(3) A net-back method or any other reasonable method to determine value.

(d)(1) Notwithstanding any other provisions of this section, except paragraph (h) of this section, if the maximum price permitted by Federal law at which any residue gas or gas plant products may be sold is less than the value determined pursuant to this section, then MMS shall accept such maximum price as the value. For the purposes of this section, price limitations set by any State or local government shall not be considered as a maximum price permitted by Federal law.

(2) The limitation prescribed by paragraph (d)(1) of this section shall not apply to residue gas sold pursuant to a warranty contract and valued pursuant to paragraph (b)(2) of this section.

(e)(1) Where the value is determined pursuant to paragraph (c) of this section, the lessee shall retain all data relevant to the determination of royalty value. Such data shall be subject to review and audit, and MMS will direct a lessee to use a different value if it determines upon review or audit that the reported value is inconsistent with the requirements of these regulations.

(2) Any Federal lessee will make available upon request to the authorized MMS or State representatives, to the Office of the Inspector General of the Department of the Interior, or other persons authorized to receive such information, arm's-length sales and volume data for like-quality residue gas and gas plant products sold, purchased or otherwise obtained by the lessee from the same processing plant or from nearby processing plants.

(3) A lessee shall notify MMS if it has determined any value pursuant to paragraph (c)(2) or (c)(3) of this

section. The notification shall be by letter to the MMS Associate Director for Minerals Revenue Management or his/her designee. The letter shall identify the valuation method to be used and contain a brief description of the procedure to be followed. The notification required by this paragraph is a one-time notification due no later than the end of the month following the month the lessee first reports royalties on a Form MMS-2014 using a valuation method authorized by paragraph (c)(2) or (c)(3) of this section, and each time there is a change in a method under paragraph (c)(2) or (c)(3) of this section.

(f) If MMS determines that a lessee has not properly determined value, the lessee shall pay the difference, if any, between royalty payments made based upon the value it has used and the royalty payments that are due based upon the value established by MMS. The lessee shall also pay interest computed on that difference pursuant to 30 CFR 218.54. If the lessee is entitled to a credit, MMS will provide instructions for the taking of that credit.

(g) The lessee may request a value determination from MMS. In that event, the lessee shall propose to MMS a value determination method, and may use that method in determining value for royalty purposes until MMS issues its decision. The lessee shall submit all available data relevant to its proposal. The MMS shall expeditiously determine the value based upon the lessee's proposal and any additional information MMS deems necessary. In making a value determination, MMS may use any of the valuation criteria authorized by this subpart. That determination shall remain effective for the period stated therein. After MMS issues its determination, the lessee shall make the adjustments in accordance with paragraph (f) of this section.

(h) Notwithstanding any other provision of this section, under no circumstances shall the value of production for royalty purposes be less than the gross proceeds accruing to the lessee for residue gas and/or any gas plant products, less applicable transportation allowances and processing allowances determined pursuant to this subpart.

(i) The lessee must place residue gas and gas plant products in marketable condition and market the residue gas and gas plant products for the mutual benefit of the lessee and the lessor at no cost to the Federal Government. Where the value established under this section is determined by a lessee's gross proceeds, that value will be increased to the extent that the gross proceeds have been reduced because the purchaser, or any other person, is providing certain services the cost of which ordinarily is the responsibility of the lessee to place the residue gas or gas plant products in marketable condition or to market the residue gas and gas plant products.

(j) Value shall be based on the highest price a prudent lessee can receive through legally enforceable claims under its contract. Absent contract revision or amendment, if the lessee fails to take proper or timely action to receive prices or benefits to which it is entitled it must pay royalty at a value based upon that obtainable price or benefit. Contract revisions or amendments shall be in writing and signed by all parties to an arm's-length contract. If the lessee makes timely application for a price increase or benefit allowed under its contract but the purchaser refuses, and the lessee takes reasonable measures, which are documented, to force purchaser compliance, the lessee will owe no additional royalties unless or until monies or consideration resulting from the price increase or additional benefits are received. This paragraph shall not be construed to permit a lessee to avoid its royalty payment obligation in situations where a purchaser fails to pay, in whole or in part, or timely, for a quantity of residue gas or gas plant product.

(k) Notwithstanding any provision in these regulations to the contrary, no review, reconciliation, monitoring, or other like process that results in a redetermination by MMS of value under this section shall be considered final or binding against the Federal Government or its beneficiaries until the audit period is formally closed.

(l) Certain information submitted to MMS to support valuation proposals, including transportation allowances, processing allowances or extraordinary cost allowances, is exempted from disclosure by the Freedom of Information Act, 5 U.S.C. 552, or other Federal law. Any data specified by law to be privileged, confidential, or otherwise exempt, will be maintained in a confidential manner in accordance with applicable law and regulations. All requests for information about determinations made under this part are to be submitted in accordance with the Freedom of Information Act regulation of the Department of the Interior, 43 CFR part 2.

[53 FR 1272, Jan. 15, 1988, as amended at 56 FR 46530, Sept. 13, 1991; 61 FR 5465, Feb. 12, 1996; 62 FR 65762, Dec. 16, 1997]

#### **§ 206.154 Determination of quantities and qualities for computing royalties.**



top

(a)(1) Royalties shall be computed on the basis of the quantity and quality of unprocessed gas at the

point of royalty settlement approved by BLM or MMS for onshore and OCS leases, respectively.

(2) If the value of gas determined pursuant to §206.152 of this subpart is based upon a quantity and/or quality that is different from the quantity and/or quality at the point of royalty settlement, as approved by BLM or MMS, that value shall be adjusted for the differences in quantity and/or quality.

(b)(1) For residue gas and gas plant products, the quantity basis for computing royalties due is the monthly net output of the plant even though residue gas and/or gas plant products may be in temporary storage.

(2) If the value of residue gas and/or gas plant products determined pursuant to §206.153 of this subpart is based upon a quantity and/or quality of residue gas and/or gas plant products that is different from that which is attributable to a lease, determined in accordance with paragraph (c) of this section, that value shall be adjusted for the differences in quantity and/or quality.

(c) The quantity of the residue gas and gas plant products attributable to a lease shall be determined according to the following procedure:

(1) When the net output of the processing plant is derived from gas obtained from only one lease, the quantity of the residue gas and gas plant products on which computations of royalty are based is the net output of the plant.

(2) When the net output of a processing plant is derived from gas obtained from more than one lease producing gas of uniform content, the quantity of the residue gas and gas plant products allocable to each lease shall be in the same proportions as the ratios obtained by dividing the amount of gas delivered to the plant from each lease by the total amount of gas delivered from all leases.

(3) When the net output of a processing plant is derived from gas obtained from more than one lease producing gas of nonuniform content, the quantity of the residue gas allocable to each lease will be determined by multiplying the amount of gas delivered to the plant from the lease by the residue gas content of the gas, and dividing the arithmetical product thus obtained by the sum of the similar arithmetical products separately obtained for all leases from which gas is delivered to the plant, and then multiplying the net output of the residue gas by the arithmetic quotient obtained. The net output of gas plant products allocable to each lease will be determined by multiplying the amount of gas delivered to the plant from the lease by the gas plant product content of the gas, and dividing the arithmetical product thus obtained by the sum of the similar arithmetical products separately obtained for all leases from which gas is delivered to the plant, and then multiplying the net output of each gas plant product by the arithmetic quotient obtained.

(4) A lessee may request MMS approval of other methods for determining the quantity of residue gas and gas plant products allocable to each lease. If approved, such method will be applicable to all gas production from Federal leases that is processed in the same plant.

(d)(1) No deductions may be made from the royalty volume or royalty value for actual or theoretical losses. Any actual loss of unprocessed gas that may be sustained prior to the royalty settlement metering or measurement point will not be subject to royalty provided that such loss is determined to have been unavoidable by BLM or MMS, as appropriate.

(2) Except as provided in paragraph (d)(1) of this section and 30 CFR 202.151(c), royalties are due on 100 percent of the volume determined in accordance with paragraphs (a) through (c) of this section. There can be no reduction in that determined volume for actual losses after the quantity basis has been determined or for theoretical losses that are claimed to have taken place. Royalties are due on 100 percent of the value of the unprocessed gas, residue gas, and/or gas plant products as provided in this subpart, less applicable allowances. There can be no deduction from the value of the unprocessed gas, residue gas, and/or gas plant products to compensate for actual losses after the quantity basis has been determined, or for theoretical losses that are claimed to have taken place.

[53 FR 1272, Jan. 15, 1988, as amended at 61 FR 5465, Feb. 12, 1996]

#### § 206.155 Accounting for comparison.



top

(a) Except as provided in paragraph (b) of this section, where the lessee (or a person to whom the lessee has transferred gas pursuant to a non-arm's-length contract or without a contract) processes the lessee's gas and after processing the gas the residue gas is not sold pursuant to an arm's-length contract, the value, for royalty purposes, shall be the greater of (1) the combined value, for royalty

purposes, of the residue gas and gas plant products resulting from processing the gas determined pursuant to §206.153 of this subpart, plus the value, for royalty purposes, of any condensate recovered downstream of the point of royalty settlement without resorting to processing determined pursuant to §206.102 of this subpart; or (2) the value, for royalty purposes, of the gas prior to processing determined in accordance with §206.152 of this subpart.

(b) The requirement for accounting for comparison contained in the terms of leases will govern as provided in §206.150(b) of this subpart. When accounting for comparison is required by the lease terms, such accounting for comparison shall be determined in accordance with paragraph (a) of this section.

[53 FR 1272, Jan. 15, 1988, as amended at 61 FR 5465, Feb. 12, 1996]

#### **§ 206.156 Transportation allowances—general.**



(a) Where the value of gas has been determined pursuant to §206.152 or §206.153 of this subpart at a point (e.g., sales point or point of value determination) off the lease, MMS shall allow a deduction for the reasonable actual costs incurred by the lessee to transport unprocessed gas, residue gas, and gas plant products from a lease to a point off the lease including, if appropriate, transportation from the lease to a gas processing plant off the lease and from the plant to a point away from the plant.

(b) Transportation costs must be allocated among all products produced and transported as provided in §206.157.

(c)(1) Except as provided in paragraph (c)(3) of this section, for unprocessed gas valued in accordance with §206.152 of this subpart, the transportation allowance deduction on the basis of a sales type code may not exceed 50 percent of the value of the unprocessed gas determined under §206.152 of this subpart.

(2) Except as provided in paragraph (c)(3) of this section, for gas production valued in accordance with §206.153 of this subpart, the transportation allowance deduction on the basis of a sales type code may not exceed 50 percent of the value of the residue gas or gas plant product determined under §206.153 of this subpart. For purposes of this section, natural gas liquids will be considered one product.

(3) Upon request of a lessee, MMS may approve a transportation allowance deduction in excess of the limitations prescribed by paragraphs (c)(1) and (c)(2) of this section. The lessee must demonstrate that the transportation costs incurred in excess of the limitations prescribed in paragraphs (c)(1) and (c)(2) of this section were reasonable, actual, and necessary. An application for exception (using Form MMS-4393, Request to Exceed Regulatory Allowance Limitation) must contain all relevant and supporting documentation necessary for MMS to make a determination. Under no circumstances may the value for royalty purposes under any sales type code be reduced to zero.

(d) If, after a review or audit, MMS determines that a lessee has improperly determined a transportation allowance authorized by this subpart, then the lessee must pay any additional royalties, plus interest, determined in accordance with 30 CFR 218.54, or will be entitled to a credit, with interest. If the lessee takes a deduction for transportation on Form MMS-2014 by improperly netting the allowance against the sales value of the unprocessed gas, residue gas, and gas plant products instead of reporting the allowance as a separate entry, MMS may assess a civil penalty under 30 CFR part 241.

[53 FR 1272, Jan. 15, 1988, as amended at 61 FR 5465, Feb. 12, 1996; 64 FR 43288, Aug. 10, 1999; 73 FR 15890, Mar. 26, 2008]

#### **§ 206.157 Determination of transportation allowances.**



(a) *Arm's-length transportation contracts.* (1)(i) For transportation costs incurred by a lessee under an arm's-length contract, the transportation allowance shall be the reasonable, actual costs incurred by the lessee for transporting the unprocessed gas, residue gas and/or gas plant products under that contract, except as provided in paragraphs (a)(1)(ii) and (a)(1)(iii) of this section, subject to monitoring, review, audit, and adjustment. The lessee shall have the burden of demonstrating that its contract is arm's-length. MMS' prior approval is not required before a lessee may deduct costs incurred under an arm's-length contract. Such allowances shall be subject to the provisions of paragraph (f) of this section. The lessee must claim a transportation allowance by reporting it as a separate entry on the Form MMS-2014.

(ii) In conducting reviews and audits, MMS will examine whether or not the contract reflects more than the consideration actually transferred either directly or indirectly from the lessee to the transporter for the transportation. If the contract reflects more than the total consideration, then the MMS may require that the transportation allowance be determined in accordance with paragraph (b) of this section.

(iii) If the MMS determines that the consideration paid pursuant to an arm's-length transportation contract does not reflect the reasonable value of the transportation because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then MMS shall require that the transportation allowance be determined in accordance with paragraph (b) of this section. When MMS determines that the value of the transportation may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's transportation costs.

(2)(i) If an arm's-length transportation contract includes more than one product in a gaseous phase and the transportation costs attributable to each product cannot be determined from the contract, the total transportation costs shall be allocated in a consistent and equitable manner to each of the products transported in the same proportion as the ratio of the volume of each product (excluding waste products which have no value) to the volume of all products in the gaseous phase (excluding waste products which have no value). Except as provided in this paragraph, no allowance may be taken for the costs of transporting lease production which is not royalty bearing without MMS approval.

(ii) Notwithstanding the requirements of paragraph (i), the lessee may propose to MMS a cost allocation method on the basis of the values of the products transported. MMS shall approve the method unless it determines that it is not consistent with the purposes of the regulations in this part.

(3) If an arm's-length transportation contract includes both gaseous and liquid products and the transportation costs attributable to each cannot be determined from the contract, the lessee shall propose an allocation procedure to MMS. The lessee may use the transportation allowance determined in accordance with its proposed allocation procedure until MMS issues its determination on the acceptability of the cost allocation. The lessee shall submit all relevant data to support its proposal. MMS shall then determine the gas transportation allowance based upon the lessee's proposal and any additional information MMS deems necessary. The lessee must submit the allocation proposal within 3 months of claiming the allocated deduction on the Form MMS-2014.

(4) Where the lessee's payments for transportation under an arm's-length contract are not based on a dollar per unit, the lessee shall convert whatever consideration is paid to a dollar value equivalent for the purposes of this section.

(5) Where an arm's-length sales contract price or a posted price includes a provision whereby the listed price is reduced by a transportation factor, MMS will not consider the transportation factor to be a transportation allowance. The transportation factor may be used in determining the lessee's gross proceeds for the sale of the product. The transportation factor may not exceed 50 percent of the base price of the product without MMS approval.

(b) *Non-arm's-length or no contract.* (1) If a lessee has a non-arm's-length transportation contract or has no contract, including those situations where the lessee performs transportation services for itself, the transportation allowance will be based upon the lessee's reasonable actual costs as provided in this paragraph. All transportation allowances deducted under a non-arm's-length or no contract situation are subject to monitoring, review, audit, and adjustment. The lessee must claim a transportation allowance by reporting it as a separate entry on the Form MMS-2014. When necessary or appropriate, MMS may direct a lessee to modify its estimated or actual transportation allowance deduction.

(2) The transportation allowance for non-arm's-length or no-contract situations shall be based upon the lessee's actual costs for transportation during the reporting period, including operating and maintenance expenses, overhead, and either depreciation and a return on undepreciated capital investment in accordance with paragraph (b)(2)(iv)(A) of this section, or a cost equal to the initial depreciable investment in the transportation system multiplied by a rate of return in accordance with paragraph (b)(2)(iv)(B) of this section. Allowable capital costs are generally those costs for depreciable fixed assets (including costs of delivery and installation of capital equipment) which are an integral part of the transportation system.

(i) Allowable operating expenses include: Operations supervision and engineering; operations labor; fuel; utilities; materials; ad valorem property taxes; rent; supplies; and any other directly allocable and attributable operating expense which the lessee can document.

(ii) Allowable maintenance expenses include: Maintenance of the transportation system; maintenance of equipment; maintenance labor; and other directly allocable and attributable maintenance expenses which the lessee can document.

(iii) Overhead directly attributable and allocable to the operation and maintenance of the transportation system is an allowable expense. State and Federal income taxes and severance taxes and other fees, including royalties, are not allowable expenses.

(iv) A lessee may use either depreciation or a return on depreciable capital investment. After a lessee has elected to use either method for a transportation system, the lessee may not later elect to change to the other alternative without approval of the MMS.

(A) To compute depreciation, the lessee may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves which the transportation system services, or a unit of production method. After an election is made, the lessee may not change methods without MMS approval. A change in ownership of a transportation system shall not alter the depreciation schedule established by the original transporter/lessee for purposes of the allowance calculation. With or without a change in ownership, a transportation system shall be depreciated only once. Equipment shall not be depreciated below a reasonable salvage value.

(B) The MMS shall allow as a cost an amount equal to the allowable initial capital investment in the transportation system multiplied by the rate of return determined pursuant to paragraph (b)(2)(v) of this section. No allowance shall be provided for depreciation. This alternative shall apply only to transportation facilities first placed in service after March 1, 1988.

(v) The rate of return must be 1.3 times the industrial rate associated with Standard & Poor's BBB rating. The BBB rate must be the monthly average rate as published in Standard & Poor's Bond Guide for the first month for which the allowance is applicable. The rate must be redetermined at the beginning of each subsequent calendar year.

(3)(i) The deduction for transportation costs shall be determined on the basis of the lessee's cost of transporting each product through each individual transportation system. Where more than one product in a gaseous phase is transported, the allocation of costs to each of the products transported shall be made in a consistent and equitable manner in the same proportion as the ratio of the volume of each product (excluding waste products which have no value) to the volume of all products in the gaseous phase (excluding waste products which have no value). Except as provided in this paragraph, the lessee may not take an allowance for transporting a product which is not royalty bearing without MMS approval.

(ii) Notwithstanding the requirements of paragraph (b)(3)(i), the lessee may propose to the MMS a cost allocation method on the basis of the values of the products transported. MMS shall approve the method unless it determines that it is not consistent with the purposes of the regulations in this part.

(4) Where both gaseous and liquid products are transported through the same transportation system, the lessee shall propose a cost allocation procedure to MMS. The lessee may use the transportation allowance determined in accordance with its proposed allocation procedure until MMS issues its determination on the acceptability of the cost allocation. The lessee shall submit all relevant data to support its proposal. MMS shall then determine the transportation allowance based upon the lessee's proposal and any additional information MMS deems necessary. The lessee must submit the allocation proposal within 3 months of claiming the allocated deduction on the Form MMS-2014.

(5) You may apply for an exception from the requirement to compute actual costs under paragraphs (b) (1) through (b)(4) of this section.

(i) The MMS will grant the exception if:

(A) The transportation system has a tariff filed with the Federal Energy Regulatory Commission (FERC) or a state regulatory agency, that FERC or the state regulatory agency has permitted to become effective, and

(B) Third parties are paying prices, including discounted prices, under the tariff to transport gas on the system under arm's-length transportation contracts.

(ii) If MMS approves the exception, you must calculate your transportation allowance for each production month based on the lesser of the volume-weighted average of the rates paid by the third parties under arm's-length transportation contracts during that production month or the non-arm's-length payment by the lessee to the pipeline.

(iii) If during any production month there are no prices paid under the tariff by third parties to transport gas on the system under arm's-length transportation contracts, you may use the volume-weighted average of the rates paid by third parties under arm's-length transportation contracts in the most recent preceding production month in which the tariff remains in effect and third parties paid such rates, for up to five successive production months. You must use the non-arm's-length payment by the lessee to the

pipeline if it is less than the volume-weighted average of the rates paid by third parties under arm's-length contracts.

(c) *Reporting requirements* —(1) *Arm's-length contracts.* (i) You must use a separate entry on Form MMS-2014 to notify MMS of a transportation allowance.

(ii) The MMS may require you to submit arm's-length transportation contracts, production agreements, operating agreements, and related documents. Recordkeeping requirements are found at part 207 of this chapter.

(iii) You may not use a transportation allowance that was in effect before March 1, 1988. You must use the provisions of this subpart to determine your transportation allowance.

(2) *Non-arm's-length or no contract.* (i) You must use a separate entry on Form MMS-2014 to notify MMS of a transportation allowance.

(ii) For new transportation facilities or arrangements, base your initial deduction on estimates of allowable gas transportation costs for the applicable period. Use the most recently available operations data for the transportation system or, if such data are not available, use estimates based on data for similar transportation systems. Paragraph (e) of this section will apply when you amend your report based on your actual costs.

(iii) The MMS may require you to submit all data used to calculate the allowance deduction. Recordkeeping requirements are found at part 207 of this chapter.

(iv) If you are authorized under paragraph (b)(5) of this section to use an exception to the requirement to calculate your actual transportation costs, you must follow the reporting requirements of paragraph (c)(1) of this section.

(v) You may not use a transportation allowance that was in effect before March 1, 1988. You must use the provisions of this subpart to determine your transportation allowance.

(d) *Interest and assessments.* (1) If a lessee deducts a transportation allowance on its Form MMS-2014 that exceeds 50 percent of the value of the gas transported without obtaining prior approval of MMS under §206.156, the lessee shall pay interest on the excess allowance amount taken from the date such amount is taken to the date the lessee files an exception request with MMS.

(2) If a lessee erroneously reports a transportation allowance which results in an underpayment of royalties, interest shall be paid on the amount of that underpayment.

(3) Interest required to be paid by this section shall be determined in accordance with 30 CFR 218.54.

(e) *Adjustments.* (1) If the actual transportation allowance is less than the amount the lessee has taken on Form MMS-2014 for each month during the allowance reporting period, the lessee shall be required to pay additional royalties due plus interest computed under 30 CFR 218.54 from the allowance reporting period when the lessee took the deduction to the date the lessee repays the difference to MMS. If the actual transportation allowance is greater than the amount the lessee has taken on Form MMS-2014 for each month during the allowance reporting period, the lessee shall be entitled to a credit without interest.

(2) For lessees transporting production from onshore Federal leases, the lessee must submit a corrected Form MMS-2014 to reflect actual costs, together with any payment, in accordance with instructions provided by MMS.

(3) For lessees transporting gas production from leases on the OCS, if the lessee's estimated transportation allowance exceeds the allowance based on actual costs, the lessee must submit a corrected Form MMS-2014 to reflect actual costs, together with its payment, in accordance with instructions provided by MMS. If the lessee's estimated transportation allowance is less than the allowance based on actual costs, the refund procedure will be specified by MMS.

(f) *Allowable costs in determining transportation allowances.* You may include, but are not limited to (subject to the requirements of paragraph (g) of this section), the following costs in determining the arm's-length transportation allowance under paragraph (a) of this section or the non-arm's-length transportation allowance under paragraph (b) of this section. You may not use any cost as a deduction that duplicates all or part of any other cost that you use under this paragraph.

(1) *Firm demand charges paid to pipelines.* You may deduct firm demand charges or capacity

reservation fees paid to a pipeline, including charges or fees for unused firm capacity that you have not sold before you report your allowance. If you receive a payment from any party for release or sale of firm capacity after reporting a transportation allowance that included the cost of that unused firm capacity, or if you receive a payment or credit from the pipeline for penalty refunds, rate case refunds, or other reasons, you must reduce the firm demand charge claimed on the Form MMS-2014 by the amount of that payment. You must modify the Form MMS-2014 by the amount received or credited for the affected reporting period, and pay any resulting royalty and late payment interest due;

(2) *Gas supply realignment (GSR) costs.* The GSR costs result from a pipeline reforming or terminating supply contracts with producers to implement the restructuring requirements of FERC Orders in 18 CFR part 284;

(3) *Commodity charges.* The commodity charge allows the pipeline to recover the costs of providing service;

(4) *Wheeling costs.* Hub operators charge a wheeling cost for transporting gas from one pipeline to either the same or another pipeline through a market center or hub. A hub is a connected manifold of pipelines through which a series of incoming pipelines are interconnected to a series of outgoing pipelines;

(5) *Gas Research Institute (GRI) fees.* The GRI conducts research, development, and commercialization programs on natural gas related topics for the benefit of the U.S. gas industry and gas customers. GRI fees are allowable provided such fees are mandatory in FERC-approved tariffs;

(6) *Annual Charge Adjustment (ACA) fees.* FERC charges these fees to pipelines to pay for its operating expenses;

(7) *Payments (either volumetric or in value) for actual or theoretical losses.* However, theoretical losses are not deductible in non-arm's-length transportation arrangements unless the transportation allowance is based on arm's-length transportation rates charged under a FERC- or state regulatory-approved tariff under paragraph (b)(5) of this section. If you receive volumes or credit for line gain, you must reduce your transportation allowance accordingly and pay any resulting royalties and late payment interest due;

(8) *Temporary storage services.* This includes short duration storage services offered by market centers or hubs (commonly referred to as "parking" or "banking"), or other temporary storage services provided by pipeline transporters, whether actual or provided as a matter of accounting. Temporary storage is limited to 30 days or less; and

(9) *Supplemental costs for compression, dehydration, and treatment of gas.* MMS allows these costs only if such services are required for transportation and exceed the services necessary to place production into marketable condition required under §§206.152(i) and 206.153(i) of this part.

(10) *Costs of surety.* You may deduct the costs of securing a letter of credit, or other surety, that the pipeline requires you as a shipper to maintain under an arm's-length transportation contract.

(g) *Nonallowable costs in determining transportation allowances.* Lessees may not include the following costs in determining the arm's-length transportation allowance under paragraph (a) of this section or the non-arm's-length transportation allowance under paragraph (b) of this section:

(1) *Fees or costs incurred for storage.* This includes storing production in a storage facility, whether on or off the lease, for more than 30 days;

(2) *Aggregator/marketer fees.* This includes fees you pay to another person (including your affiliates) to market your gas, including purchasing and reselling the gas, or finding or maintaining a market for the gas production;

(3) *Penalties you incur as shipper.* These penalties include, but are not limited to:

(i) *Over-delivery cash-out penalties.* This includes the difference between the price the pipeline pays you for over-delivered volumes outside the tolerances and the price you receive for over-delivered volumes within the tolerances;

(ii) *Scheduling penalties.* This includes penalties you incur for differences between daily volumes delivered into the pipeline and volumes scheduled or nominated at a receipt or delivery point;

(iii) *Imbalance penalties.* This includes penalties you incur (generally on a monthly basis) for differences between volumes delivered into the pipeline and volumes scheduled or nominated at a receipt or

delivery point; and

(iv) *Operational penalties.* This includes fees you incur for violation of the pipeline's curtailment or operational orders issued to protect the operational integrity of the pipeline;

(4) *Intra-hub transfer fees.* These are fees you pay to hub operators for administrative services (e.g., title transfer tracking) necessary to account for the sale of gas within a hub;

(5) *Fees paid to brokers.* This includes fees paid to parties who arrange marketing or transportation, if such fees are separately identified from aggregator/marketer fees;

(6) *Fees paid to scheduling service providers.* This includes fees paid to parties who provide scheduling services, if such fees are separately identified from aggregator/marketer fees;

(7) *Internal costs.* This includes salaries and related costs, rent/space costs, office equipment costs, legal fees, and other costs to schedule, nominate, and account for sale or movement of production; and

(8) *Other nonallowable costs.* Any cost you incur for services you are required to provide at no cost to the lessor.

(h) *Other transportation cost determinations.* Use this section when calculating transportation costs to establish value using a netback procedure or any other procedure that requires deduction of transportation costs.

[53 FR 1272, Jan. 15, 1988, as amended at 53 FR 45762, Nov. 14, 1988; 61 FR 5465, Feb. 12, 1996; 62 FR 65762, Dec. 16, 1997; 70 FR 11878, Mar. 10, 2005; 73 FR 15891, Mar. 26, 2008]

#### § 206.158 Processing allowances—general.



[top](#)

(a) Where the value of gas is determined pursuant to §206.153 of this subpart, a deduction shall be allowed for the reasonable actual costs of processing.

(b) Processing costs must be allocated among the gas plant products. A separate processing allowance must be determined for each gas plant product and processing plant relationship. Natural gas liquids (NGL's) shall be considered as one product.

(c)(1) Except as provided in paragraph (d)(2) of this section, the processing allowance shall not be applied against the value of the residue gas. Where there is no residue gas MMS may designate an appropriate gas plant product against which no allowance may be applied.

(2) Except as provided in paragraph (c)(3) of this section, the processing allowance deduction on the basis of an individual product shall not exceed 662/3percent of the value of each gas plant product determined in accordance with §206.153 of this subpart (such value to be reduced first for any transportation allowances related to postprocessing transportation authorized by §206.156 of this subpart).

(3) Upon request of a lessee, MMS may approve a processing allowance in excess of the limitation prescribed by paragraph (c)(2) of this section. The lessee must demonstrate that the processing costs incurred in excess of the limitation prescribed in paragraph (c)(2) of this section were reasonable, actual, and necessary. An application for exception (using Form MMS-4393, Request to Exceed Regulatory Allowance Limitation) shall contain all relevant and supporting documentation for MMS to make a determination. Under no circumstances shall the value for royalty purposes of any gas plant product be reduced to zero.

(d)(1) Except as provided in paragraph (d)(2) of this section, no processing cost deduction shall be allowed for the costs of placing lease products in marketable condition, including dehydration, separation, compression, or storage, even if those functions are performed off the lease or at a processing plant. Where gas is processed for the removal of acid gases, commonly referred to as "sweetening," no processing cost deduction shall be allowed for such costs unless the acid gases removed are further processed into a gas plant product. In such event, the lessee shall be eligible for a processing allowance as determined in accordance with this subpart. However, MMS will not grant any processing allowance for processing lease production which is not royalty bearing.

(2)(i) If the lessee incurs extraordinary costs for processing gas production from a gas production operation, it may apply to MMS for an allowance for those costs which shall be in addition to any other processing allowance to which the lessee is entitled pursuant to this section. Such an allowance may be granted only if the lessee can demonstrate that the costs are, by reference to standard industry conditions and practice, extraordinary, unusual, or unconventional.

(ii) Prior MMS approval to continue an extraordinary processing cost allowance is not required. However, to retain the authority to deduct the allowance the lessee must report the deduction to MMS in a form and manner prescribed by MMS.

(e) If MMS determines that a lessee has improperly determined a processing allowance authorized by this subpart, then the lessee must pay any additional royalties, plus interest determined under 30 CFR 218.54, or will be entitled to a credit with interest. If the lessee takes a deduction for processing on Form MMS-2014 by improperly netting the allowance against the sales value of the gas plant products instead of reporting the allowance as a separate entry, MMS may assess a civil penalty under 30 CFR part 241.

[53 FR 1272, Jan. 15, 1988, as amended at 61 FR 5466, Feb. 12, 1996; 64 FR 43288, Aug. 10, 1999; 73 FR 15891, Mar. 26, 2008]

#### § 206.159 Determination of processing allowances.



(a) *Arm's-length processing contracts.* (1)(i) For processing costs incurred by a lessee under an arm's-length contract, the processing allowance shall be the reasonable actual costs incurred by the lessee for processing the gas under that contract, except as provided in paragraphs (a)(1)(ii) and (a)(1)(iii) of this section, subject to monitoring, review, audit, and adjustment. The lessee shall have the burden of demonstrating that its contract is arm's-length. MMS' prior approval is not required before a lessee may deduct costs incurred under an arm's-length contract. The lessee must claim a processing allowance by reporting it as a separate entry on the Form MMS-2014.

(ii) In conducting reviews and audits, MMS will examine whether the contract reflects more than the consideration actually transferred either directly or indirectly from the lessee to the processor for the processing. If the contract reflects more than the total consideration, then the MMS may require that the processing allowance be determined in accordance with paragraph (b) of this section.

(iii) If MMS determines that the consideration paid pursuant to an arm's-length processing contract does not reflect the reasonable value of the processing because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and lessor, then MMS shall require that the processing allowance be determined in accordance with paragraph (b) of this section. When MMS determines that the value of the processing may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's processing costs.

(2) If an arm's-length processing contract includes more than one gas plant product and the processing costs attributable to each product can be determined from the contract, then the processing costs for each gas plant product shall be determined in accordance with the contract. No allowance may be taken for the costs of processing lease production which is not royalty-bearing.

(3) If an arm's-length processing contract includes more than one gas plant product and the processing costs attributable to each product cannot be determined from the contract, the lessee shall propose an allocation procedure to MMS. The lessee may use its proposed allocation procedure until MMS issues its determination. The lessee shall submit all relevant data to support its proposal. MMS shall then determine the processing allowance based upon the lessee's proposal and any additional information MMS deems necessary. No processing allowance will be granted for the costs of processing lease production which is not royalty bearing. The lessee must submit the allocation proposal within 3 months of claiming the allocated deduction on Form MMS-2014.

(4) Where the lessee's payments for processing under an arm's-length contract are not based on a dollar per unit basis, the lessee shall convert whatever consideration is paid to a dollar value equivalent for the purposes of this section.

(b) *Non-arm's-length or no contract.* (1) If a 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 will be based upon the lessee's reasonable actual costs as provided in this paragraph. All processing allowances deducted under a non-arm's-length or no-contract situation are subject to monitoring, review, audit, and adjustment. The lessee must claim a processing allowance by reflecting it

as a separate entry on the Form MMS-2014. When necessary or appropriate, MMS may direct a lessee to modify its estimated or actual processing allowance.

(2) The processing allowance for non-arm's-length or no-contract situations shall be based upon the lessee's actual costs for processing during the reporting period, including operating and maintenance expenses, overhead, and either depreciation and a return on undepreciated capital investment in accordance with paragraph (b)(2)(iv)(A) of this section, or a cost equal to the initial depreciable investment in the processing plant multiplied by a rate of return in accordance with paragraph (b)(2)(iv)(B) of this section. Allowable capital costs are generally those costs for depreciable fixed assets (including costs of delivery and installation of capital equipment) which are an integral part of the processing plant.

(i) Allowable operating expenses include: Operations supervision and engineering; operations labor; fuel; utilities; materials; ad valorem property taxes; rent; supplies; and any other directly allocable and attributable operating expense which the lessee can document.

(ii) Allowable maintenance expenses include: Maintenance of the processing plant; maintenance of equipment; maintenance labor; and other directly allocable and attributable maintenance expenses which the lessee can document.

(iii) Overhead directly attributable and allocable to the operation and maintenance of the processing plant is an allowable expense. State and Federal income taxes and severance taxes, including royalties, are not allowable expenses.

(iv) A lessee may use either depreciation or a return on depreciable capital investment. When a lessee has elected to use either method for a processing plant, the lessee may not later elect to change to the other alternative without approval of the MMS.

(A) To compute depreciation, the lessee may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves which the processing plant services, or a unit-of-production method. After an election is made, the lessee may not change methods without MMS approval. A change in ownership of a processing plant shall not alter the depreciation schedule established by the original processor/lessee for purposes of the allowance calculation. With or without a change in ownership, a processing plant shall be depreciated only once. Equipment shall not be depreciated below a reasonable salvage value.

(B) The MMS shall allow as a cost an amount equal to the allowable initial capital investment in the processing plant multiplied by the rate of return determined pursuant to paragraph (b)(2)(v) of this section. No allowance shall be provided for depreciation. This alternative shall apply only to plants first placed in service after March 1, 1988.

(v) The rate of return must be the industrial rate associated with Standard and Poor's BBB rating. The rate of return must be the monthly average rate as published in Standard and Poor's Bond Guide for the first month for which the allowance is applicable. The rate must be redetermined at the beginning of each subsequent calendar year.

(3) The processing allowance for each gas plant product shall be determined based on the lessee's reasonable and actual cost of processing the gas. Allocation of costs to each gas plant product shall be based upon generally accepted accounting principles. The lessee may not take an allowance for the costs of processing lease production which is not royalty bearing.

(4) A lessee may apply to MMS for an exception from the requirement that it compute actual costs in accordance with paragraphs (b)(1) through (b)(3) of this section. The MMS may grant the exception only if: (i) The lessee has arm's-length contracts for processing other gas production at the same processing plant; and (ii) at least 50 percent of the gas processed annually at the plant is processed pursuant to arm's-length processing contracts; if the MMS grants the exception, the lessee shall use as its processing allowance the volume weighted average prices charged other persons pursuant to arm's-length contracts for processing at the same plant.

(c) *Reporting requirements* —(1) *Arm's-length contracts.* (i) The lessee must notify MMS of an allowance based on incurred costs by using a separate entry on the Form MMS-2014.

(ii) The MMS may require that a lessee submit arm's-length processing contracts and related documents. Documents shall be submitted within a reasonable time, as determined by MMS.

(2) *Non-arm's-length or no contract.* (i) The lessee must notify MMS of an allowance based on the incurred costs by using a separate entry on the Form MMS-2014.

(ii) For new processing plants, the lessee's initial deduction shall include estimates of the allowable gas processing costs for the applicable period. Cost estimates shall be based upon the most recently available operations data for the plant or, if such data are not available, the lessee shall use estimates based upon industry data for similar gas processing plants.

(iii) Upon request by MMS, the lessee shall submit all data used to prepare the allowance deduction. The data shall be provided within a reasonable period of time, as determined by MMS.

(iv) If the lessee is authorized to use the volume weighted average prices charged other persons as its processing allowance in accordance with paragraph (b)(4) of this section, it shall follow the reporting requirements of paragraph (c)(1) of this section.

(d) *Interest.* (1) If a lessee deducts a processing allowance on its Form MMS-2014 that exceeds 66 2/3 percent of the value of the gas processed without obtaining prior approval of MMS under § 206.158, the lessee shall pay interest on the excess allowance amount taken from the date such amount is taken to the date the lessee files an exception request with MMS.

(2) If a lessee erroneously reports a processing allowance which results in an underpayment of royalties, interest shall be paid on the amount of that underpayment.

(3) Interest required to be paid by this section shall be determined in accordance with 30 CFR 218.54.

(e) *Adjustments.* (1) If the actual processing allowance is less than the amount the lessee has taken on Form MMS-2014 for each month during the allowance reporting period, the lessee shall pay additional royalties due plus interest computed under 30 CFR 218.54 from the allowance reporting period when the lessee took the deduction to the date the lessee repays the difference to MMS. If the actual processing allowance is greater than the amount the lessee has taken on Form MMS-2014 for each month during the allowance reporting period, the lessee shall be entitled to a credit with interest.

(2) For lessees processing production from onshore Federal leases, the lessee must submit a corrected Form MMS-2014 to reflect actual costs, together with any payment, in accordance with instructions provided by MMS.

(3) For lessees processing gas production from leases on the OCS, if the lessee's estimated processing allowance exceeds the allowance based on actual costs, the lessee must submit a corrected Form MMS-2014 to reflect actual costs, together with its payment, in accordance with instructions provided by MMS. If the lessee's estimated costs were less than the actual costs, the refund procedure will be specified by MMS.

(f) *Other processing cost determinations.* The provisions of this section shall apply to determine processing costs when establishing value using a net back valuation procedure or any other procedure that requires deduction of processing costs.

[53 FR 1272, Jan. 15, 1988, as amended at 53 FR 45762, Nov. 14, 1988; 61 FR 5466, Feb. 12, 1996; 64 FR 43288, Aug. 10, 1999; 73 FR 15891, Mar. 26, 2008]

## § 206.160 Operating allowances.



[top](#)

Notwithstanding any other provisions in these regulations, an operating allowance may be used for the purpose of computing payment obligations when specified in the notice of sale and the lease. The allowance amount or formula shall be specified in the notice of sale and in the lease agreement.

[61 FR 3804, Feb. 2, 1996]

## Subpart E—Indian Gas



[top](#)

Source: 64 FR 43515, Aug. 10, 1999, unless otherwise noted.

## § 206.170 What does this subpart contain?

[top](#)

This subpart contains royalty valuation provisions applicable to Indian lessees.

(a) This subpart applies to all gas production from Indian (tribal and allotted) oil and gas leases (except leases on the Osage Indian Reservation). The purpose of this subpart is to establish the value of production for royalty purposes consistent with the mineral leasing laws, other applicable laws, and lease terms. This subpart does not apply to Federal leases.

(b) If the specific provisions of any Federal statute, treaty, negotiated agreement, settlement agreement resulting from any administrative or judicial proceeding, or Indian oil and gas lease are inconsistent with any regulation in this subpart, then the Federal statute, treaty, negotiated agreement, settlement agreement, or lease will govern to the extent of that inconsistency.

(c) You may calculate the value of production for royalty purposes under methods other than those the regulations in this title require, but only if you, the tribal lessor, and MMS jointly agree to the valuation methodology. For leases on Indian allotted lands, you and MMS must agree to the valuation methodology.

(d) All royalty payments you make to MMS are subject to monitoring, review, audit, and adjustment.

(e) The regulations in this subpart are intended to ensure that the trust responsibilities of the United States with respect to the administration of Indian oil and gas leases are discharged in accordance with the requirements of the governing mineral leasing laws, treaties, and lease terms.

#### **§ 206.171 What definitions apply to this subpart?**

[top](#)

The following definitions apply to this subpart and to subpart J of part 202 of this title:

*Accounting for comparison* means the same as dual accounting.

*Active spot market* means a market where one or more MMS-acceptable publications publish bidweek prices (or if bidweek prices are not available, first of the month prices) for at least one index-pricing point in the index zone.

*Allowance* means a deduction in determining value for royalty purposes. Processing allowance means an allowance for the reasonable, actual costs of processing gas determined under this subpart. Transportation allowance means an allowance for the reasonable, actual cost of transportation determined under this subpart.

*Approved Federal Agreement (AFA)* means a unit or communitization agreement approved under departmental regulations.

*Area* means a geographic region at least as large as the defined limits of an oil or gas field, in which oil or gas lease products have similar quality, economic, or legal characteristics. An area may be all lands within the boundaries of an Indian reservation.

*Arm's-length contract* means a contract or agreement that has been arrived at in the marketplace between independent, nonaffiliated persons with opposing economic interests regarding that contract. For purposes of this subpart, two persons are affiliated if one person controls, is controlled by, or is under common control with another person. The following percentages (based on the instruments of ownership of the voting securities of an entity, or based on other forms of ownership) determine if persons are affiliated:

(1) Ownership in excess of 50 percent constitutes control.

(2) Ownership of 10 through 50 percent creates a presumption of control.

(3) Ownership of less than 10 percent creates a presumption of noncontrol which MMS may rebut if it demonstrates actual or legal control, including the existence of interlocking directorates. Notwithstanding any other provisions of this subpart, contracts between relatives, either by blood or by marriage, are not arm's-length contracts. MMS may require the lessee to certify the percentage of ownership or control of

the entity. To be considered arm's-length for any production month, a contract must meet the requirements of this definition for that production month as well as when the contract was executed.

*Audit* means a review, conducted under generally accepted accounting and auditing standards, of royalty payment compliance activities of lessees or other persons who pay royalties, rents, or bonuses on Indian leases.

*BIA* means the Bureau of Indian Affairs of the Department of the Interior.

*BLM* means the Bureau of Land Management of the Department of the Interior.

*Compression* means raising the pressure of gas.

*Condensate* means liquid hydrocarbons (normally exceeding 40 degrees of API gravity) recovered at the surface without resorting to processing. Condensate is the mixture of liquid hydrocarbons that results from condensation of petroleum hydrocarbons existing initially in a gaseous phase in an underground reservoir.

*Contract* means any oral or written agreement, including amendments or revisions thereto, between two or more persons and enforceable by law that with due consideration creates an obligation.

*Dedicated* means a contractual commitment to deliver gas production (or a specified portion of production) from a lease or well when that production is specified in a sales contract *and* that production must be sold pursuant to that contract to the extent that production occurs from that lease or well.

*Drip condensate* means any condensate recovered downstream of the facility measurement point without resorting to processing. Drip condensate includes condensate recovered as a result of its becoming a liquid during the transportation of the gas removed from the lease or recovered at the inlet of a gas processing plant by mechanical means, often referred to as scrubber condensate.

*Dual Accounting* (or *accounting for comparison*) refers to the requirement to pay royalty based on a value which is the higher of the value of gas prior to processing less any applicable allowances as compared to the combined value of drip condensate, residue gas, and gas plant products after processing, less applicable allowances.

*Entitlement* (or *entitled share*) means the gas production from a lease, or allocable to lease acreage under the terms of an AFA, multiplied by the operating rights owner's percentage of interest ownership in the lease or the acreage.

*Facility measurement point* (or *point of royalty settlement*) means the point where the BLM-approved measurement device is located for determining the volume of gas removed from the lease. The facility measurement point may be on the lease or off-lease with BLM approval.

*Field* means a geographic region situated over one or more subsurface oil and gas reservoirs encompassing at least the outermost boundaries of all oil and gas accumulations known to be within those reservoirs vertically projected to the land surface. Onshore fields are usually given names and their official boundaries are often designated by oil and gas regulatory agencies in the respective States in which the fields are located.

*Gas* means any fluid, either combustible or noncombustible, hydrocarbon or nonhydrocarbon, which is extracted from a reservoir and which has neither independent shape nor volume, but tends to expand indefinitely. It is a substance that exists in a gaseous or rarefied state under standard temperature and pressure conditions.

*Gas plant products* means separate marketable elements, compounds, or mixtures, whether in liquid, gaseous, or solid form, resulting from processing gas. However, it does not include residue gas.

*Gathering* means the movement of lease production to a central accumulation or treatment point on the lease, unit, or communitized area; or a central accumulation or treatment point off the lease, unit, or communitized area as approved by BLM operations personnel.

*Gross proceeds* (for royalty payment purposes) means the total monies and other consideration accruing to an oil and gas lessee for the disposition of unprocessed gas, residue gas, and gas plant products produced. Gross proceeds includes, but is not limited to, payments to the lessee for certain services such as compression, dehydration, measurement, or field gathering to the extent that the lessee is obligated to perform them at no cost to the Indian lessor, and payments for gas processing rights. Gross proceeds, as applied to gas, also includes but is not limited to reimbursements for

severance taxes and other reimbursements. Tax reimbursements are part of the gross proceeds accruing to a lessee even though the Indian royalty interest is exempt from taxation. Monies and other consideration, including the forms of consideration identified in this paragraph, to which a lessee is contractually or legally entitled but which it does not seek to collect through reasonable efforts are also part of gross proceeds.

*Index* means the calculated composite price (\$/MMBtu) of spot-market sales published by a publication that meets MMS-established criteria for acceptability at the index-pricing point.

*Index-pricing point (IPP)* means any point on a pipeline for which there is an index.

*Index zone* means a field or an area with an active spot market and published indices applicable to that field or area that are acceptable to MMS under §206.172(d)(2).

*Indian allottee* means any Indian for whom land or an interest in land is held in trust by the United States or who holds title subject to Federal restriction against alienation.

*Indian tribe* means any Indian tribe, band, nation, pueblo, community, rancheria, colony, or other group of Indians for which any land or interest in land is held in trust by the United States or which is subject to Federal restriction against alienation.

*Lease* means any 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 lease products—or the land area covered by that authorization, whichever is required by the context. For purposes of this subpart, this definition excludes Federal leases.

*Lease products* means any leased minerals attributable to, originating from, or allocated to a lease.

*Lessee* means any person to whom the United States, a tribe, and/or individual Indian landowner issues a lease, and any person who has been assigned an obligation to make royalty or other payments required by the lease. This includes any person who has an interest in a lease (including operating rights owners) as well as an operator or payor who has no interest in the lease but who has assumed the royalty payment responsibility.

*Like-quality lease products* means lease products which have similar chemical, physical, and legal characteristics.

*Marketable condition* means a condition in which lease products are sufficiently free from impurities and otherwise so conditioned that a purchaser will accept them under a sales contract typical for the field or area.

*MMS* means the Minerals Management Service, Department of the Interior. MMS includes, where appropriate, tribal auditors acting under agreements under the Federal Oil and Gas Royalty Management Act of 1982, 30 U.S.C. 1701 *et seq.* or other applicable agreements.

*Minimum royalty* means that minimum amount of annual royalty that the lessee must pay as specified in the lease or in applicable leasing regulations.

*Natural gas liquids (NGL's)* means those gas plant products consisting of ethane, propane, butane, or heavier liquid hydrocarbons.

*Net-back method (or work-back method)* means a method for calculating market value of gas at the lease under which costs of transportation, processing, and manufacturing are deducted from the proceeds received for, or the value of, the gas, residue gas, or gas plant products, and any extracted, processed, or manufactured products, at the first point at which reasonable values for any such products may be determined by a sale under an arm's-length contract or comparison to other sales of such products.

*Net output* means the quantity of residue gas and each gas plant product that a processing plant produces.

*Net profit share* means the specified share of the net profit from production of oil and gas as provided in the agreement.

*Operating rights owner (or working interest owner)* means any person who owns operating rights in a lease subject to this subpart. A record title owner is the owner of operating rights under a lease except to

the extent that the operating rights or a portion thereof have been transferred from record title (see BLM regulations at 43 CFR 3100.0-5(d)).

*Person* means any individual, firm, corporation, association, partnership, consortium, or joint venture (when established as a separate entity).

*Point of royalty measurement* means the same as facility measurement point.

*Processing* means any process designed to remove elements or compounds (hydrocarbon and nonhydrocarbon) from gas, including absorption, adsorption, or refrigeration. Field processes which normally take place on or near the lease, such as natural pressure reduction, mechanical separation, heating, cooling, dehydration, desulphurization (or "sweetening"), and compression, are not considered processing. The changing of pressures and/or temperatures in a reservoir is not considered processing.

*Residue gas* means that hydrocarbon gas consisting principally of methane resulting from processing gas.

*Sales type code* means the contract type or general disposition (e.g., arm's-length or non-arm's-length) of production from the lease. The sales type code applies to the sales contract, or other disposition, and not to the arm's-length or non-arm's-length nature of a transportation or processing allowance.

*Spot sales agreement* means a contract wherein a seller agrees to sell to a buyer a specified amount of unprocessed gas, residue gas, or gas plant products at a specified price over a fixed period, usually of short duration. It also does not normally require a cancellation notice to terminate, and does not contain an obligation, or imply an intent, to continue in subsequent periods.

*Takes* means when the operating rights owner sells or removes production from, or allocated to, the lease, or when such sale or removal occurs for the benefit of an operating rights owner.

*Work-back method* means the same as net-back method.

[64 FR 43515, Aug. 10, 1999, as amended at 73 FR 15891, Mar. 26, 2008]

## **§ 206.172 How do I value gas produced from leases in an index zone?**



[top](#)

(a) *What leases this section applies to.* This section explains how lessees must value, for royalty purposes, gas produced from Indian leases located in an index zone. For other leases, value must be determined under §206.174.

(1) You must use the valuation provision of this section if your lease is in an index zone and meets one of the following two requirements:

(i) Has a major portion provision;

(ii) Does not have a major portion provision, but provides for the Secretary to determine the value of production.

(2) This section does not apply to carbon dioxide, nitrogen, or other non-hydrocarbon components of the gas stream. However, if they are recovered and sold separately from the gas stream, you must determine the value of these products under §206.174.

(b) *Valuing residue gas and gas before processing.* (1) Except as provided in paragraphs (e), (f), and (g) of this section, this paragraph (b) explains how you must value the following four types of gas:

(i) Gas production before processing;

(ii) Gas production that you certify on Form MMS-4410, Certification for Not Performing Accounting for Comparison (Dual Accounting), is not processed before it flows into a pipeline with an index but which may be processed later;

(iii) Residue gas after processing; and

(iv) Gas that is never processed.

(2) The value of gas production that is not sold under an arm's-length dedicated contract is the index-based value determined under paragraph (d) of this section unless the gas was subject to a previous contract which was part of a gas contract settlement. If the previous contract was subject to a gas contract settlement and if the royalty-bearing contract settlement proceeds per MMBtu added to the 80 percent of the safety net prices calculated at §206.172(e)(4)(i) exceeds the index-based value that applies to the gas under this section (including any adjustments required under §206.176), then the value of the gas is the higher of the value determined under this section (including any adjustments required under §206.176) or §206.174.

(3) The value of gas production that is sold under an arm's-length dedicated contract is the higher of the index-based value under paragraph (d) of this section or the value of that production determined under §206.174(b).

(c) *Valuing gas that is processed before it flows into a pipeline with an index.* Except as provided in paragraphs (e), (f), and (g) of this section, this paragraph (c) explains how you must value gas that is processed before it flows into a pipeline with an index. You must value this gas production based on the higher of the following two values:

(1) The value of the gas before processing determined under paragraph (b) of this section.

(2) The value of the gas after processing, which is either the alternative dual accounting value under §206.173 or the sum of the following three values:

(i) The value of the residue gas determined under paragraph (b)(2) or (3) of this section, as applicable;

(ii) The value of the gas plant products determined under §206.174, less any applicable processing and/or transportation allowances determined under this subpart; and

(iii) The value of any drip condensate associated with the processed gas determined under subpart B of this part.

(d) *Determining the index-based value for gas production.* (1) To determine the index-based value per MMBtu for production from a lease in an index zone, you must use the following procedures:

(i) For each MMS-approved publication, calculate the average of the highest reported prices for all index-pricing points in the index zone, except for any prices excluded under paragraph (d)(6) of this section;

(ii) Sum the averages calculated in paragraph (d)(1)(i) of this section and divide by the number of publications; and

(iii) Reduce the number calculated under paragraph (d)(1)(ii) of this section by 10 percent, but not by less than 10 cents per MMBtu or more than 30 cents per MMBtu. The result is the index-based value per MMBtu for production from all leases in that index zone.

(2) MMS will publish in the Federal Register the index zones that are eligible for the index-based valuation method under this paragraph. MMS will monitor the market activity in the index zones and, if necessary, hold a technical conference to add or modify a particular index zone. Any change to the index zones will be published in the Federal Register. MMS will consider the following five factors and conditions in determining eligible index zones:

(i) Areas for which MMS-approved publications establish index prices that accurately reflect the value of production in the field or area where the production occurs;

(ii) Common markets served;

(iii) Common pipeline systems;

(iv) Simplification; and

(v) Easy identification in MMS's systems, such as counties or Indian reservations.

(3) If market conditions change so that an index-based method for determining value is no longer

appropriate for an index zone, MMS will hold a technical conference to consider disqualification of an index zone. MMS will publish notice in the Federal Register if an index zone is disqualified. If an index zone is disqualified, then production from leases in that index zone cannot be valued under this paragraph.

(4) MMS periodically will publish in the Federal Register a list of acceptable publications based on certain criteria, including, but not limited to the following five criteria:

- (i) Publications buyers and sellers frequently use;
- (ii) Publications frequently referenced in purchase or sales contracts;
- (iii) Publications that use adequate survey techniques, including the gathering of information from a substantial number of sales;
- (iv) Publications that publish the range of reported prices they use to calculate their index; and
- (v) Publications independent from DOI, lessors, and lessees.

(5) Any publication may petition MMS to be added to the list of acceptable publications.

(6) MMS may exclude an individual index price for an index zone in an MMS-approved publication if MMS determines that the index price does not accurately reflect the value of production in that index zone. MMS will publish a list of excluded indices in the Federal Register.

(7) MMS will reference which tables in the publications you must use for determining the associated index prices.

(8) The index-based values determined under this paragraph are not subject to deductions for transportation or processing allowances determined under §§206.177, 206.178, 206.179, and 206.180.

(e) *Determining the minimum value for royalty purposes of gas sold beyond the first index pricing point.*

(1) Notwithstanding any other provision of this section, the value for royalty purposes of gas production from an Indian lease that is sold beyond the first index pricing point through which it flows cannot be less than the value determined under this paragraph (e).

(2) By June 30 following any calendar year, you must calculate for each month of that calendar year your safety net price per MMBtu using the procedures in paragraph (e)(3) of this section. You must calculate a safety net price for each month and for each index zone where you have an Indian lease for which you report and pay royalties.

(3) Your safety net price (S) for an index zone is the volume-weighted average contract price per delivered MMBtu under your or your affiliate's arm's-length contracts for the disposition of residue gas or unprocessed gas produced from your Indian leases in that index zone as computed under this paragraph (e)(3).

(i) Include in your calculation only sales under those contracts that establish a delivery point beyond the first index pricing point through which the gas flows, and that include any gas produced from or allocable to one or more of your Indian leases in that index zone, even if the contract also includes gas produced from Federal, State, or fee properties. Include in your volume-weighted average calculation those volumes that are allocable to your Indian leases in that index zone.

(ii) Do not reduce the contract price for any transportation costs incurred to deliver the gas to the purchaser.

(iii) For purposes of this paragraph (e), the contract price will not include the following amounts:

(A) Any amounts you receive in compromise or settlement of a predecessor contract for that gas;

(B) Deductions for you or any other person to put gas production into marketable condition or to market the gas; and

(C) Any amounts related to marketable securities associated with the sales contract.

(4) Next, you must determine for each month the safety net differential (SND). You must perform this

calculation separately for each index zone.

(i) For each index zone, the safety net differential is equal to:  $SND = [(0.80 \times S) - (1.25 \times I)]$  where (I) is the index-based value determined under 30 CFR 206.172(d).

(ii) If the safety net differential is positive you owe additional royalties.

(5)(i) To calculate the additional royalties you owe, make the following calculation for each of your Indian leases in that index zone that produced gas that was sold beyond the first index-pricing point through which the gas flowed and that was used in the calculation in paragraph (e)(3) of this section:

Lease royalties owed =  $SND \times V \times R$ , where R = the lease royalty rate and V = the volume allocable to the lease which produced gas that was sold beyond the first index pricing point.

(ii) If gas produced from any of your Indian leases is commingled or pooled with gas produced from non-Indian properties, and if any of the combined gas is sold at a delivery point beyond the first index pricing point through which the gas flows, then the volume allocable to each Indian lease for which gas was sold beyond the first index pricing point in the calculation under paragraph (e)(5)(i) of this section is the volume produced from the lease multiplied by the proportion that the total volume of gas sold beyond the first index pricing point bears to the total volume of gas commingled or pooled from all properties.

(iii) Add the numbers calculated for each lease under paragraph (e)(5)(i) of this section. The total is the additional royalty you owe.

(6) You have the following responsibilities to comply with the minimum value for royalty purposes:

(i) You must report the safety net price for each index zone to MMS on Form MMS-4411, Safety Net Report, no later than June 30 following each calendar year;

(ii) You must pay and report on Form MMS-2014 additional royalties due no later than June 30 following each calendar year; and

(iii) MMS may order you to amend your safety net price within one year from the date your Form MMS-4411 is due or is filed, whichever is later. If MMS does not order any amendments within that one-year period, your safety net price calculation is final.

(f) *Excluding some or all tribal leases from valuation under this section.* (1) An Indian tribe may ask MMS to exclude some or all of its leases from valuation under this section. MMS will consult with BIA regarding the request.

(i) If MMS approves the request for your lease, you must value your production under §206.174 beginning with production on the first day of the second month following the date MMS publishes notice of its decision in the Federal Register.

(ii) If an Indian tribe requests exclusion from an index zone for less than all of its leases, MMS will approve the request only if the excluded leases may be segregated into one or more groups based on separate fields within the reservation.

(2) An Indian tribe may ask MMS to terminate exclusion of its leases from valuation under this section. MMS will consult with BIA regarding the request.

(i) If MMS approves the request, you must value your production under §206.172 beginning with production on the first day of the second month following the date MMS publishes notice of its decision in the Federal Register.

(ii) Termination of an exclusion under paragraph (f)(2)(i) of this section cannot take effect earlier than 1 year after the first day of the production month that the exclusion was effective.

(3) The Indian tribe's request to MMS under either paragraph (f)(1) or (2) of this section must be in the form of a tribal resolution.

(g) *Excluding Indian allotted leases from valuation under this section.* (1)(i) MMS may exclude any Indian allotted leases from valuation under this section. MMS will consult with BIA regarding the exclusion.

(ii) If MMS excludes your lease, you must value your production under §206.174 beginning with

production on the first day of the second month following the date MMS publishes notice of its decision in the Federal Register.

(iii) If MMS excludes any Indian allotted leases under this paragraph (g)(1), it will exclude all Indian allotted leases in the same field.

(2)(i) MMS may terminate the exclusion of any Indian allotted leases from valuation under this section. MMS will consult with BIA regarding the termination.

(ii) If MMS terminates the exclusion, you must value your production under §206.172 beginning with production on the first day of the second month following the date MMS publishes notice of its decision in the Federal Register.

### **§ 206.173 How do I calculate the alternative methodology for dual accounting?**



[top](#)

(a) *Electing a dual accounting method.* (1) If you are required to perform the accounting for comparison (dual accounting) under §206.176, you have two choices. You may elect to perform the dual accounting calculation according to either §206.176(a) (called actual dual accounting), or paragraph (b) of this section (called the alternative methodology for dual accounting).

(2) You must make a separate election to use the alternative methodology for dual accounting for your Indian leases in each MMS-designated area. Your election for a designated area must apply to all of your Indian leases in that area.

(i) MMS will publish in the Federal Register a list of the lease prefixes that will be associated with each designated area for purposes of this section. The MMS-designated areas are as follows:

- (A) Alabama-Coushatta;
- (B) Blackfeet Reservation;
- (C) Crow Reservation;
- (D) Fort Belknap Reservation;
- (E) Fort Berthold Reservation;
- (F) Fort Peck Reservation;
- (G) Jicarilla Apache Reservation;
- (H) MMS-designated groups of counties in the State of Oklahoma;
- (I) Navajo Reservation;
- (J) Northern Cheyenne Reservation;
- (K) Rocky Boys Reservation;
- (L) Southern Ute Reservation;
- (M) Turtle Mountain Reservation;
- (N) Ute Mountain Ute Reservation;
- (O) Uintah and Ouray Reservation;
- (P) Wind River Reservation; and
- (Q) Any other area that MMS designates. MMS will publish a new area designation in the Federal

Register.

(ii) You may elect to begin using the alternative methodology for dual accounting at the beginning of any month. The first election to use the alternative methodology will be effective from the time of election through the end of the following calendar year. Thereafter, each election to use the alternative methodology must remain in effect for 2 calendar years. You may return to the actual dual accounting method only at the beginning of the next election period or with the written approval of MMS and the tribal lessor for tribal leases, and MMS for Indian allottee leases in the designated area.

(iii) When you elect to use the alternative methodology for a designated area, you must also use the alternative methodology for any new wells commenced and any new leases acquired in the designated area during the term of the election.

(b) *Calculating value using the alternative methodology for dual accounting.* (1) The alternative methodology adjusts the value of gas before processing determined under either §206.172 or §206.174 to provide the value of the gas after processing. You must use the value of the gas after processing for royalty payment purposes. The amount of the increase depends on your relationship with the owner(s) of the plant where the gas is processed. If you have no direct or indirect ownership interest in the processing plant, then the increase is lower, as provided in the table in paragraph (b)(2)(ii) of this section. If you have a direct or indirect ownership interest in the plant where the gas is processed, the increase is higher, as provided in paragraph (b)(2)(ii) of this section.

(2) To calculate the value of the gas after processing using the alternative methodology for dual accounting, you must apply the increase to the value before processing, determined in either §206.172 or §206.174, as follows:

(i) Value of gas after processing = (value determined under either §206.172 or §206.174, as applicable) × (1 + increment for dual accounting); and

(ii) In this equation, the increment for dual accounting is the number you take from the applicable Btu range, determined under paragraph (b)(3) of this section, in the following table:

<b>BTU range</b>	<b>Increment if Lessee has no ownership interest in plant</b>	<b>Increment if lessee has an ownership interest in plant</b>
1001 to 1050	.0275	.0375
1051 to 1100	.0400	.0625
1101 to 1150	.0425	.0750
1151 to 1200	.0700	.1225
1201 to 1250	.0975	.1700
1251 to 1300	.1175	.2050
1301 to 1350	.1400	.2400
1351 to 1400	.1450	.2500
1401 to 1450	.1500	.2600
1451 to 1500	.1550	.2700
1501 to 1550	.1600	.2800
1551 to 1600	.1650	.2900

1601 to 1650	.1850	.3225
1651 to 1700	.1950	.3425
1701+	.2000	.3550

(3) The applicable Btu for purposes of this section is the volume weighted-average Btu for the lease computed from measurements at the facility measurement point(s) for gas production from the lease.

(4) If any of your gas from the lease is processed during a month, use the following two paragraphs to determine which amounts are subject to dual accounting and which dual accounting method you must use.

(i) Weighted-average Btu content determined under paragraph (b)(3) of this section is greater than 1,000 Btu's per cubic foot (Btu/cf). All gas production from the lease is subject to dual accounting and you must use the alternative method for all that gas production if you elected to use the alternative method under this section.

(ii) Weighted-average Btu content determined under paragraph (b)(3) of this section is less than or equal to 1,000 Btu/cf. Only the volumes of lease production measured at facility measurement points whose quality exceeds 1,000 Btu/cf are subject to dual accounting, and you may use the alternative methodology for these volumes. For gas measured at facility measurement points for these leases where the quality is equal to or less than 1,000 Btu/cf, you are not required to do dual accounting.

#### **§ 206.174 How do I value gas production when an index-based method cannot be used?**



(a) *Situations in which an index-based method cannot be used.* (1) Gas production must be valued under this section in the following situations.

(i) Your lease is not in an index zone (or MMS has excluded your lease from an index zone).

(ii) If your lease is in an index zone and you sell your gas under an arm's-length dedicated contract, then the value of your gas is the higher of the value received under the dedicated contract determined under §206.174(b) or the value under §206.172.

(iii) Also use this section to value any other gas production that cannot be valued under §206.172, as well as gas plant products, and to value components of the gas stream that have no Btu value (for example, carbon dioxide, nitrogen, etc.).

(2) The value for royalty purposes of gas production subject to this subpart is the value of gas determined under this section less applicable allowances determined under this subpart.

(3) You must determine the value of gas production that is processed and is subject to accounting for comparison using the procedure in §206.176.

(4) This paragraph applies if your lease has a major portion provision. It also applies if your lease does not have a major portion provision but the lease provides for the Secretary to determine value.

(i) The value of production you must initially report and pay is the value determined in accordance with the other paragraphs of this section.

(ii) MMS will determine the major portion value and notify you in the Federal Register of that value. The value of production for royalty purposes for your lease is the higher of either the value determined under this section which you initially used to report and pay royalties, or the major portion value calculated under this paragraph (a)(4). If the major portion value is higher, you must submit an amended Form MMS-2014 to MMS by the due date specified in the written notice from MMS of the major portion value. Late-payment interest under 30 CFR 218.54 on any underpayment will not begin to accrue until the date the amended Form MMS-2014 is due to MMS.

(iii) Except as provided in paragraph (a)(4)(iv) of this section, MMS will calculate the major portion value

for each designated area (which are the same designated areas as under §206.173) using values reported for unprocessed gas and residue gas on Form MMS-2014 for gas produced from leases on that Indian reservation or other designated area. MMS will array the reported prices from highest to lowest price. The major portion value is that price at which 25 percent (by volume) of the gas (starting from the highest) is sold. MMS cannot unilaterally change the major portion value after you are notified in writing of what that value is for your leases.

(iv) MMS may calculate the major portion value using different data than the data described in paragraph (a)(4)(iii) of this section or data to augment the data described in paragraph (a)(4)(iii) of this section. This may include price data reported to the State tax authority or price data from leases MMS has reviewed in the designated area. MMS may use this alternate or the augmented data source beginning with production on the first day of the month following the date MMS publishes notice in the Federal Register that it is calculating the major portion using a method in this paragraph (a)(4)(iv) of this section.

(b) *Arm's-length contracts.* (1) The value of gas, residue gas, or any gas plant product you sell under an arm's-length contract is the gross proceeds accruing to you or your affiliate, except as provided in paragraphs (b)(1)(ii)-(iv) of this section.

(i) You have the burden of demonstrating that your contract is arm's-length.

(ii) In conducting reviews and audits for gas valued based upon gross proceeds under this paragraph, MMS will examine whether or not your contract reflects the total consideration actually transferred either directly or indirectly from the buyer to you or your affiliate for the gas, residue gas, or gas plant product. If the contract does not reflect the total consideration, then MMS may require that the gas, residue gas, or gas plant product sold under that contract be valued in accordance with paragraph (c) of this section. Value may not be less than the gross proceeds accruing to you or your affiliate, including the additional consideration.

(iii) If MMS determines for gas valued under this paragraph that the gross proceeds accruing to you or your affiliate under an arm's-length contract do not reflect the value of the gas, residue gas, or gas plant products because of misconduct by or between the contracting parties, or because you otherwise have breached your duty to the lessor to market the production for the mutual benefit of you and the lessor, then MMS will require that the gas, residue gas, or gas plant product be valued under paragraphs (c)(2) or (3) of this section. In these circumstances, MMS will notify you and give you an opportunity to provide written information justifying your value.

(iv) This paragraph applies to situations where a pipeline purchases gas from a lessee according to a cash-out program under a transportation contract. For all over-delivered volumes, the royalty value is the price the pipeline is required to pay for volumes within the tolerances for over-delivery specified in the transportation contract. Use the same value for volumes that exceed the over-delivery tolerances even if those volumes are subject to a lower price specified in the transportation contract. However, if MMS determines that the price specified in the transportation contract for over-delivered volumes is unreasonably low, the lessees must value all over-delivered volumes under paragraph (c)(2) or (3) of this section.

(2) MMS may require you to certify that your arm's-length contract provisions include all of the consideration the buyer pays, either directly or indirectly, for the gas, residue gas, or gas plant product.

(c) *Non-arm's-length contracts.* If your gas, residue gas, or any gas plant product is not sold under an arm's-length contract, then you must value the production using the first applicable method of the following three methods:

(1) The gross proceeds accruing to you under your non-arm's-length contract sale (or other disposition other than by an arm's-length contract), provided that those gross proceeds are equivalent to the gross proceeds derived from, or paid under, comparable arm's-length contracts for purchases, sales, or other dispositions of like-quality gas in the same field (or, if necessary to obtain a reasonable sample, from the same area). For residue gas or gas plant products, the comparable arm's-length contracts must be for gas from the same processing plant (or, if necessary to obtain a reasonable sample, from nearby plants). In evaluating the comparability of arm's-length contracts for the purposes of these regulations, the following factors will be considered: price, time of execution, duration, market or markets served, terms, quality of gas, residue gas, or gas plant products, volume, and such other factors as may be appropriate to reflect the value of the gas, residue gas, or gas plant products.

(2) A value determined by consideration of other information relevant in valuing like-quality gas, residue gas, or gas plant products, including gross proceeds under arm's-length contracts for like-quality gas in the same field or nearby fields or areas, or for residue gas or gas plant products from the same gas plant or other nearby processing plants. Other factors to consider include prices received in spot sales of gas, residue gas or gas plant products, other reliable public sources of price or market information, and other information as to the particular lease operation or the salability of such gas, residue gas, or gas plant

products.

(3) A net-back method or any other reasonable method to determine value.

(d) *Supporting data.* If you determine the value of production under paragraph (c) of this section, you must retain all data relevant to the determination of royalty value.

(1) Such data will be subject to review and audit, and MMS will direct you to use a different value if we determine upon review or audit that the value you reported is inconsistent with the requirements of these regulations.

(2) You must make all such data available upon request to the authorized MMS or Indian representatives, to the Office of the Inspector General of the Department, or other authorized persons. This includes your arm's-length sales and volume data for like-quality gas, residue gas, and gas plant products that are sold, purchased, or otherwise obtained from the same processing plant or from nearby processing plants, or from the same or nearby field or area.

(e) *Improper values.* If MMS determines that you have not properly determined value, you must pay the difference, if any, between royalty payments made based upon the value you used and the royalty payments that are due based upon the value MMS established. You also must pay interest computed on that difference under 30 CFR 218.54. If you are entitled to a credit, MMS will provide instructions on how to take that credit.

(f) *Value guidance.* You may ask MMS for guidance in determining value. You may propose a valuation method to MMS. Submit all available data related to your proposal and any additional information MMS deems necessary. MMS will promptly review your proposal and provide you with a non-binding determination of the guidance you request.

(g) *Minimum value of production.* (1) For gas, residue gas, and gas plant products valued under this section, under no circumstances may the value of production for royalty purposes be less than the gross proceeds accruing to the lessee (including its affiliates) for gas, residue gas and/or any gas plant products, less applicable transportation allowances and processing allowances determined under this subpart.

(2) For gas plant products valued under this section and not valued under §206.173, the alternative methodology for dual accounting, the minimum value of production for each gas plant product is as follows:

(i) Leases in certain States and areas have specific minimum values.

(A) For production from leases in Colorado in the San Juan Basin, New Mexico, and Texas, the monthly average minimum price reported in commercial price bulletins for the gas plant product at Mont Belvieu, Texas, minus 8.0 cents per gallon.

(B) For production in Arizona, in Colorado outside the San Juan Basin, Minnesota, Montana, North Dakota, Oklahoma, South Dakota, Utah, and Wyoming, the monthly average minimum price reported in commercial price bulletins for the gas plant product at Conway, Kansas, minus 7.0 cents per gallon;

(ii) You may use any commercial price bulletin, but you must use the same bulletin for all of the calendar year. If the commercial price bulletin you are using stops publication, you may use a different commercial price bulletin for the remaining part of the calendar year; and (iii) If you use a commercial price bulletin that is published monthly, the monthly average minimum price is the bulletin's minimum price. If you use a commercial price bulletin that is published weekly, the monthly average minimum price is the arithmetic average of the bulletin's weekly minimum prices. If you use a commercial price bulletin that is published daily, the monthly average minimum price is the arithmetic average of the bulletin's minimum prices for each Wednesday in the month.

(h) *Marketable condition/Marketing.* You are required to place gas, residue gas, and gas plant products in marketable condition and market the gas for the mutual benefit of the lessee and the lessor at no cost to the Indian lessor. When your gross proceeds establish the value under this section, that value must be increased to the extent that the gross proceeds have been reduced because the purchaser, or any other person, is providing certain services to place the gas, residue gas, or gas plant products in marketable condition or to market the gas, the cost of which ordinarily is your responsibility.

(i) *Highest obtainable price or benefit.* For gas, residue gas, and gas plant products valued under this section, value must be based on the highest price a prudent lessee can receive through legally enforceable claims under its contract. Absent contract revision or amendment, if you fail to take proper

or timely action to receive prices or benefits to which you are entitled, you must pay royalty at a value based upon that obtainable price or benefit. Contract revisions or amendments must be in writing and signed by all parties to an arm's-length contract. If you make timely application for a price increase or benefit allowed under your contract but the purchaser refuses, and you take reasonable measures, which are documented, to force purchaser compliance, you will owe no additional royalties unless or until monies or consideration resulting from the price increase or additional benefits are received. This paragraph is not intended to permit you to avoid your royalty payment obligation in situations where your purchaser fails to pay, in whole or in part, or timely, for a quantity of gas, residue gas, or gas plant product.

(j) *Non-binding MMS reviews.* Notwithstanding any provision in these regulations to the contrary, no review, reconciliation, monitoring, or other like process that results in an MMS redetermination of value under this section will be considered final or binding against the Federal Government or its beneficiaries until the audit period is formally closed.

(k) *Confidential information.* Certain information submitted to MMS to support valuation proposals, including transportation allowances and processing allowances, may be exempted from disclosure under the Freedom of Information Act, 5 U.S.C. 552, or other Federal law. Any data specified by law to be privileged, confidential, or otherwise exempt, will be maintained in a confidential manner in accordance with applicable laws and regulations. All requests for information about determinations made under this subpart must be submitted in accordance with the Freedom of Information Act regulation of the Department of the Interior, 43 CFR part 2.

[64 FR 43515, Aug. 10, 1999, as amended at 65 FR 62614, Oct. 19, 2000]

#### **§ 206.175 How do I determine quantities and qualities of production for computing royalties?**



[top](#)

(a) For unprocessed gas, you must pay royalties on the quantity and quality at the facility measurement point BLM either allowed or approved.

(b) For residue gas and gas plant products, you must pay royalties on your share of the monthly net output of the plant even though residue gas and/or gas plant products may be in temporary storage.

(c) If you have no ownership interest in the processing plant and you do not operate the plant, you may use the contract volume allocation to determine your share of plant products.

(d) If you have an ownership interest in the plant or if you operate it, use the following procedure to determine the quantity of the residue gas and gas plant products attributable to you for royalty payment purposes:

(1) When the net output of the processing plant is derived from gas obtained from only one lease, the quantity of the residue gas and gas plant products on which you must pay royalty is the net output of the plant.

(2) When the net output of a processing plant is derived from gas obtained from more than one lease producing gas of uniform content, the quantity of the residue gas and gas plant products allocable to each lease must be in the same proportions as the ratios obtained by dividing the amount of gas delivered to the plant from each lease by the total amount of gas delivered from all leases.

(3) When the net output of a processing plant is derived from gas obtained from more than one lease producing gas of non-uniform content, the volumes of residue gas and gas plant products allocable to each lease are based on theoretical volumes of residue gas and gas plant products measured in the lease gas stream. You must calculate the portion of net plant output of residue gas and gas plant products attributable to each lease as follows:

(i) First, compute the theoretical volumes of residue gas and of gas plant products attributable to the lease by multiplying the lease volume of the gas stream by the tested residue gas content (mole percentage) or gas plant product (GPM) content of the gas stream;

(ii) Second, calculate the theoretical volumes of residue gas and of gas plant products delivered from all leases by summing the theoretical volumes of residue gas and of gas plant products delivered from each lease; and

(iii) Third, calculate the theoretical quantities of net plant output of residue gas and of gas plant products attributable to each lease by multiplying the net plant output of residue gas, or gas plant products, by the ratio in which the theoretical volumes of residue gas, or gas plant products, is the numerator and the theoretical volume of residue gas, or gas plant products, delivered from all leases is the denominator.

(4) You may request MMS approval of other methods for determining the quantity of residue gas and gas plant products allocable to each lease. If MMS approves a different method, it will be applicable to all gas production from your Indian leases that is processed in the same plant.

(e) You may not take any deductions from the royalty volume or royalty value for actual or theoretical losses. Any actual loss of unprocessed gas incurred prior to the facility measurement point will not be subject to royalty if BLM determines that the loss was unavoidable.

#### **§ 206.176 How do I perform accounting for comparison?**



(a) This section applies if the gas produced from your Indian lease is processed and that Indian lease requires accounting for comparison (also referred to as actual dual accounting). Except as provided in paragraphs (b) and (c) of this section, the actual dual accounting value, for royalty purposes, is the greater of the following two values:

(1) The combined value of the following products:

(i) The residue gas and gas plant products resulting from processing the gas determined under either §206.172 or §206.174, less any applicable allowances; and

(ii) Any drip condensate associated with the processed gas recovered downstream of the point of royalty settlement without resorting to processing determined under §206.52, less applicable allowances.

(2) The value of the gas prior to processing determined under either §206.172 or §206.174, including any applicable allowances.

(b) If you are required to account for comparison, you may elect to use the alternative dual accounting methodology provided for in §206.173 instead of the provisions in paragraph (a) of this section.

(c) Accounting for comparison is not required for gas if no gas from the lease is processed until after the gas flows into a pipeline with an index located in an index zone or into a mainline pipeline not in an index zone. If you do not perform dual accounting, you must certify to MMS that gas flows into such a pipeline before it is processed.

(d) Except as provided in paragraph (e) of this section, if you value any gas production from a lease for a month using the dual accounting provisions of this section or the alternative dual accounting methodology of §206.173, then the value of that gas is the minimum value for any other gas production from that lease for that month flowing through the same facility measurement point.

(e) If the weighted-average Btu quality for your lease is less than 1,000 Btu's per cubic foot, see §206.173(b)(4)(ii) to determine if you must perform a dual accounting calculation.

#### **Transportation Allowances**



#### **§ 206.177 What general requirements regarding transportation allowances apply to me?**



(a) When you value gas under §206.174 at a point off the lease, unit, or communitized area (for example, sales point or point of value determination), you may deduct from value a transportation allowance to reflect the value, for royalty purposes, at the lease, unit, or communitized area. The allowance is based on the reasonable actual costs you incurred to transport unprocessed gas, residue gas, or gas plant products from a lease to a point off the lease, unit, or communitized area. This would

include, if appropriate, transportation from the lease to a gas processing plant off the lease, unit, or communitized area and from the plant to a point away from the plant. You may not deduct any allowance for gathering costs.

(b) You must allocate transportation costs among all products you produce and transport as provided in §206.178.

(c)(1) Except as provided in paragraphs (c)(2) and (3) of this section, your transportation allowance deduction for each sales type code may not exceed 50 percent of the value of the unprocessed gas, residue gas, or gas plant product. For purposes of this section, natural gas liquids are considered one product.

(2) If you ask MMS, MMS may approve a transportation allowance deduction in excess of the limitations in paragraph (c)(1) of this section. To receive this approval, you must demonstrate that the transportation costs incurred in excess of the limitations in paragraph (c)(1) of this section were reasonable, actual, and necessary. Under no circumstances may an allowance reduce the value for royalty purposes under any sales type code to zero.

(3) Your application for exception (using Form MMS-4393, Request to Exceed Regulatory Allowance Limitation) must contain all relevant and supporting documentation necessary for MMS to make a determination.

(d) If MMS conducts a review or audit and determines that you have improperly determined a transportation allowance authorized by this subpart, then you will be required to pay any additional royalties, plus interest determined in accordance with 30 CFR 218.54. Alternatively, you may be entitled to a credit, but you will not receive any interest on your overpayment.

[64 FR 43515, Aug. 10, 1999, as amended at 73 FR 15891, Mar. 26, 2008]

## § 206.178 How do I determine a transportation allowance?



[top](#)

(a) *Determining a transportation allowance under an arm's-length contract.* (1) This paragraph explains how to determine your allowance if you have an arm's-length transportation contract.

(i) If you have an arm's-length contract for transportation of your production, the transportation allowance is the reasonable, actual costs you incur for transporting the unprocessed gas, residue gas and/or gas plant products under that contract. Paragraphs (a)(1)(ii) and (iii) of this section provide a limited exception. You have the burden of demonstrating that your contract is arm's-length. Your allowances also are subject to paragraph (e) of this section. You are required to submit to MMS a copy of your arm's-length transportation contract(s) and all subsequent amendments to the contract(s) within 2 months of the date MMS receives your report which claims the allowance on the Form MMS-2014.

(ii) When either MMS or a tribe conducts reviews and audits, they will examine whether or not the contract reflects more than the consideration actually transferred either directly or indirectly from you to the transporter of the transportation. If the contract reflects more than the total consideration, then MMS may require that the transportation allowance be determined under paragraph (b) of this section.

(iii) If MMS determines that the consideration paid under an arm's-length transportation contract does not reflect the value of the transportation because of misconduct by or between the contracting parties, or because you otherwise have breached your duty to the lessor to market the production for the mutual benefit of you and the lessor, then MMS will require that the transportation allowance be determined under paragraph (b) of this section. In these circumstances, MMS will notify you and give you an opportunity to provide written information justifying your transportation costs.

(2) This paragraph explains how to allocate the costs to each product if your arm's-length transportation contract includes more than one product in a gaseous phase and the transportation costs attributable to each product cannot be determined from the contract.

(i) If your arm's-length transportation contract includes more than one product in a gaseous phase and the transportation costs attributable to each product cannot be determined from the contract, the total transportation costs must be allocated in a consistent and equitable manner to each of the products transported. To make this allocation, use the same proportion as the ratio that the volume of each product (excluding waste products which have no value) bears to the volume of all products in the gaseous phase (excluding waste products which have no value). Except as provided in this paragraph, you cannot take an allowance for the costs of transporting lease production that is not royalty bearing

without MMS approval, or without lessor approval on tribal leases.

(ii) As an alternative to paragraph (a)(2)(i) of this section, you may propose to MMS a cost allocation method based on the values of the products transported. MMS will approve the method if we determine that it meets one of the two following requirements:

(A) The methodology in paragraph (a)(2)(i) of this section cannot be applied; and

(B) Your proposal is more reasonable than the methodology in paragraph (a)(2)(i) of this section.

(3) This paragraph explains how to allocate costs to each product if your arm's-length transportation contract includes both gaseous and liquid products and the transportation costs attributable to each cannot be determined from the contract.

(i) If your arm's-length transportation contract includes both gaseous and liquid products and the transportation costs attributable to each cannot be determined from the contract, you must propose an allocation procedure to MMS. You may use the transportation allowance determined in accordance with your proposed allocation procedure until MMS decides whether to accept your cost allocation.

(ii) You are required to submit all relevant data to support your allocation proposal. MMS will then determine the gas transportation allowance based upon your proposal and any additional information MMS deems necessary.

(4) If your payments for transportation under an arm's-length contract are not based on a dollar per unit price, you must convert whatever consideration is paid to a dollar value equivalent for the purposes of this section.

(5) Where an arm's-length sales contract price includes a reduction for a transportation factor, MMS will not consider the transportation factor to be a transportation allowance. You may use the transportation factor to determine your gross proceeds for the sale of the product. However, the transportation factor may not exceed 50 percent of the base price of the product without MMS approval.

(b) *Determining a transportation allowance under a non-arm's-length or no contract.* (1) This paragraph explains how to determine your allowance if you have a non-arm's-length transportation contract or no contract.

(i) When you have a non-arm's-length transportation contract or no contract, including those situations where you perform transportation services for yourself, the transportation allowance is based upon your reasonable, allowable, actual costs for transportation as provided in this paragraph.

(ii) All transportation allowances deducted under a non-arm's-length or no contract situation are subject to monitoring, review, audit, and adjustment. You must submit the actual cost information to support the allowance to MMS on Form MMS-4295, Gas Transportation Allowance Report, within 3 months after the end of the 12-month period to which the allowance applies. However, MMS may approve a longer time period. MMS will monitor the allowance deductions to ensure that deductions are reasonable and allowable. When necessary or appropriate, MMS may require you to modify your actual transportation allowance deduction.

(2) This paragraph explains what actual transportation costs are allowable under a non-arm's-length contract or no contract situation. The transportation allowance for non-arm's-length or no-contract situations is based upon your actual costs for transportation during the reporting period. Allowable costs include operating and maintenance expenses, overhead, and either depreciation and a return on undepreciated capital investment (in accordance with paragraph (b)(2)(iv)(A) of this section), or a cost equal to the initial depreciable investment in the transportation system multiplied by a rate of return in accordance with paragraph (b)(2)(iv)(B) of this section. Allowable capital costs are generally those costs for depreciable fixed assets (including costs of delivery and installation of capital equipment) that are an integral part of the transportation system.

(i) Allowable operating expenses include operations supervision and engineering, operations labor, fuel, utilities, materials, ad valorem property taxes, rent, supplies, and any other directly allocable and attributable operating expense that you can document.

(ii) Allowable maintenance expenses include maintenance of the transportation system, maintenance of equipment, maintenance labor, and other directly allocable and attributable maintenance expenses that you can document.

(iii) Overhead directly attributable and allocable to the operation and maintenance of the transportation

system is an allowable expense. State and Federal income taxes and severance taxes and other fees, including royalties, are not allowable expenses.

(iv) You may use either depreciation with a return on undepreciated capital investment or a return on depreciable capital investment. After you have elected to use either method for a transportation system, you may not later elect to change to the other alternative without MMS approval.

(A) To compute depreciation, you may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves that the transportation system services, or a unit of production method. Once you make an election, you may not change methods without MMS approval. A change in ownership of a transportation system will not alter the depreciation schedule that the original transporter/lessee established for purposes of the allowance calculation. With or without a change in ownership, a transportation system may be depreciated only once. Equipment may not be depreciated below a reasonable salvage value. To compute a return on undepreciated capital investment, you will multiply the undepreciated capital investment in the transportation system by the rate of return determined under paragraph (b)(2)(v) of this section.

(B) To compute a return on depreciable capital investment, you will multiply the initial capital investment in the transportation system by the rate of return determined under paragraph (b)(2)(v) of this section. No allowance will be provided for depreciation. This alternative will apply only to transportation facilities first placed in service after March 1, 1988.

(v) The rate of return is the industrial rate associated with Standard and Poor's BBB rating. The rate of return is the monthly average rate as published in *Standard and Poor's Bond Guide* for the first month of the reporting period for which the allowance is applicable and is effective during the reporting period. The rate must be redetermined at the beginning of each subsequent transportation allowance reporting period that is determined under paragraph (b)(4) of this section.

(3) This paragraph explains how to allocate transportation costs to each product and transportation system.

(i) The deduction for transportation costs must be determined based on your cost of transporting each product through each individual transportation system. If you transport more than one product in a gaseous phase, the allocation of costs to each of the products transported must be made in a consistent and equitable manner. The allocation should be in the same proportion that the volume of each product (excluding waste products that have no value) bears to the volume of all products in the gaseous phase (excluding waste products that have no value). Except as provided in this paragraph, you may not take an allowance for transporting a product that is not royalty bearing without MMS approval.

(ii) As an alternative to the requirements of paragraph (b)(3)(i) of this section, you may propose to MMS a cost allocation method based on the values of the products transported. MMS will approve the method upon determining that it meets one of the two following requirements:

(A) The methodology in paragraph (b)(3)(i) of this section cannot be applied; and

(B) Your proposal is more reasonable than the method in paragraph (b)(3)(i) of this section.

(4) Your transportation allowance under this paragraph (b) must be determined based upon a calendar year or other period if you and MMS agree to an alternative.

(5) If you transport both gaseous and liquid products through the same transportation system, you must propose a cost allocation procedure to MMS. You may use the transportation allowance determined in accordance with your proposed allocation procedure until MMS issues its determination on the acceptability of the cost allocation. You are required to submit all relevant data to support your proposal. MMS will then determine the transportation allowance based upon your proposal and any additional information MMS deems necessary.

(c) *Using the alternative transportation calculation when you have a non-arm's-length or no contract.* (1) As an alternative to computing your transportation allowance under paragraph (b) of this section, you may use as the transportation allowance 10 percent of your gross proceeds but not to exceed 30 cents per MMBtu.

(2) Your election to use the alternative transportation allowance calculation in paragraph (c)(1) of this section must be made at the beginning of a month and must remain in effect for an entire calendar year. Your first election will remain in effect until the end of the succeeding calendar year, except for elections effective January 1 that will be effective only for that calendar year.

(d) *Reporting your transportation allowance.* (1) If MMS requests, you must submit all data used to determine your transportation allowance. The data must be provided within a reasonable period of time that MMS will determine.

(2) You must report transportation allowances as a separate entry on Form MMS-2014. MMS may approve a different reporting procedure on allottee leases, and with lessor approval on tribal leases.

(e) *Adjusting incorrect allowances.* If for any month the transportation allowance you are entitled to is less than the amount you took on Form MMS-2014, you are required to report and pay additional royalties due, plus interest computed under 30 CFR 218.54 from the first day of the first month you deducted the improper transportation allowance until the date you pay the royalties due. If the transportation allowance you are entitled to is greater than the amount you took on Form MMS-2014 for any royalties during the reporting period, you are entitled to a credit. No interest will be paid on the overpayment.

(f) *Determining allowable costs for transportation allowances.* Lessees may include, but are not limited to, the following costs in determining the arm's-length transportation allowance under paragraph (a) of this section or the non-arm's-length transportation allowance under paragraph (b) of this section:

(1) *Firm demand charges paid to pipelines.* You must limit the allowable costs for the firm demand charges to the applicable rate per MMBtu multiplied by the actual volumes transported. You may not include any losses incurred for previously purchased but unused firm capacity. You also may not include any gains associated with releasing firm capacity. If you receive a payment or credit from the pipeline for penalty refunds, rate case refunds, or other reasons, you must reduce the firm demand charge claimed on the Form MMS-2014. You must modify the Form MMS-2014 by the amount received or credited for the affected reporting period.

(2) *Gas supply realignment (GSR) costs.* The GSR costs result from a pipeline reforming or terminating supply contracts with producers to implement the restructuring requirements of FERC orders in 18 CFR part 284.

(3) *Commodity charges.* The commodity charge allows the pipeline to recover the costs of providing service.

(4) *Wheeling costs.* Hub operators charge a wheeling cost for transporting gas from one pipeline to either the same or another pipeline through a market center or hub. A hub is a connected manifold of pipelines through which a series of incoming pipelines are interconnected to a series of outgoing pipelines.

(5) *Gas Research Institute (GRI) fees.* The GRI conducts research, development, and commercialization programs on natural gas related topics for the benefit of the U.S. gas industry and gas customers. GRI fees are allowable provided such fees are mandatory in FERC-approved tariffs.

(6) *Annual Charge Adjustment (ACA) fees.* FERC charges these fees to pipelines to pay for its operating expenses.

(7) *Payments (either volumetric or in value) for actual or theoretical losses.* This paragraph does not apply to non-arm's-length transportation arrangements.

(8) *Temporary storage services.* This includes short duration storage services offered by market centers or hubs (commonly referred to as "parking" or "banking"), or other temporary storage services provided by pipeline transporters, whether actual or provided as a matter of accounting. Temporary storage is limited to 30 days or less.

(9) *Supplemental costs for compression, dehydration, and treatment of gas.* MMS allows these costs only if such services are required for transportation and exceed the services necessary to place production into marketable condition required under §206.174(h).

(g) *Determining nonallowable costs for transportation allowances.* Lessees may not include the following costs in determining the arm's-length transportation allowance under paragraph (a) of this section or the non-arm's-length transportation allowance under paragraph (b) of this section:

(1) *Fees or costs incurred for storage.* This includes storing production in a storage facility, whether on or off the lease, for more than 30 days.

(2) *Aggregator/marketer fees.* This includes fees you pay to another person (including your affiliates) to market your gas, including purchasing and reselling the gas, or finding or maintaining a market for the

gas production.

(3) *Penalties you incur as shipper.* These penalties include, but are not limited to the following:

(i) *Over-delivery cash-out penalties.* This includes the difference between the price the pipeline pays you for over-delivered volumes outside the tolerances and the price you receive for over-delivered volumes within tolerances.

(ii) *Scheduling penalties.* This includes penalties you incur for differences between daily volumes delivered into the pipeline and volumes scheduled or nominated at a receipt or delivery point.

(iii) *Imbalance penalties.* This includes penalties you incur (generally on a monthly basis) for differences between volumes delivered into the pipeline and volumes scheduled or nominated at a receipt or delivery point.

(iv) *Operational penalties.* This includes fees you incur for violation of the pipeline's curtailment or operational orders issued to protect the operational integrity of the pipeline.

(4) *Intra-hub transfer fees.* These are fees you pay to hub operators for administrative services (e.g., title transfer tracking) necessary to account for the sale of gas within a hub.

(5) *Other nonallowable costs.* Any cost you incur for services you are required to provide at no cost to the lessor.

(h) *Other transportation cost determinations.* You must follow the provisions of this section to determine transportation costs when establishing value using either a net-back valuation procedure or any other procedure that allows deduction of actual transportation costs.

[64 FR 43515, Aug. 10, 1999, as amended at 73 FR 15891, Mar. 26, 2008]

## Processing Allowances



[top](#)

### § 206.179 What general requirements regarding processing allowances apply to me?



[top](#)

(a) When you value any gas plant product under §206.174, you may deduct from value the reasonable actual costs of processing.

(b) You must allocate processing costs among the gas plant products. You must determine a separate processing allowance for each gas plant product and processing plant relationship. Natural gas liquids are considered as one product.

(c) The processing allowance deduction based on an individual product may not exceed 66 2/3 percent of the value of each gas plant product determined under §206.174. Before you calculate the 66 2/3 percent limit, you must first reduce the value for any transportation allowances related to post-processing transportation authorized under §206.177.

(d) Processing cost deductions will not be allowed for placing lease products in marketable condition. These costs include among others, dehydration, separation, compression upstream of the facility measurement point, or storage, even if those functions are performed off the lease or at a processing plant. Costs for the removal of acid gases, commonly referred to as sweetening, are not allowed unless the acid gases removed are further processed into a gas plant product. In such event, you will be eligible for a processing allowance determined under this subpart. However, MMS will not grant any processing allowance for processing lease production that is not royalty bearing.

(e) You will be allowed a reasonable amount of residue gas royalty free for operation of the processing plant, but no allowance will be made for expenses incidental to marketing, except as provided in 30 CFR part 206. In those situations where a processing plant processes gas from more than one lease, only that proportionate share of your residue gas necessary for the operation of the processing plant will be allowed royalty free.

(f) You do not owe royalty on residue gas, or any gas plant product resulting from processing gas, that is reinjected into a reservoir within the same lease, unit, or approved Federal agreement, until such time as those products are finally produced from the reservoir for sale or other disposition. This paragraph applies only when the reinjection is included in a BLM-approved plan of development or operations.

(g) If MMS determines that you have determined an improper processing allowance authorized by this subpart, then you will be required to pay any additional royalties plus late payment interest determined under 30 CFR 218.54. Alternatively, you may be entitled to a credit, but you will not receive any interest on your overpayment.

#### **§ 206.180 How do I determine an actual processing allowance?**



(a) *Determining a processing allowance if you have an arm's-length processing contract.* (1) This paragraph explains how you determine an allowance under an arm's-length processing contract.

(i) The processing allowance is the reasonable actual costs you incur to process the gas under that contract. Paragraphs (a)(1)(ii) and (iii) of this section provide a limited exception. You have the burden of demonstrating that your contract is arm's-length. You are required to submit to MMS a copy of your arm's-length contract(s) and all subsequent amendments to the contract(s) within 2 months of the date MMS receives your first report that deducts the allowance on the Form MMS-2014.

(ii) When MMS conducts reviews and audits, we will examine whether the contract reflects more than the consideration actually transferred either directly or indirectly from you to the processor for the processing. If the contract reflects more than the total consideration, then MMS may require that the processing allowance be determined under paragraph (b) of this section.

(iii) If MMS determines that the consideration paid under an arm's-length processing contract does not reflect the value of the processing because of misconduct by or between the contracting parties, or because you otherwise have breached your duty to the lessor to market the production for the mutual benefit of you and the lessor, then MMS will require that the processing allowance be determined under paragraph (b) of this section. In these circumstances, MMS will notify you and give you an opportunity to provide written information justifying your processing costs.

(2) If your arm's-length processing contract includes more than one gas plant product and the processing costs attributable to each product can be determined from the contract, then the processing costs for each gas plant product must be determined in accordance with the contract. You may not take an allowance for the costs of processing lease production that is not royalty-bearing.

(3) If your arm's-length processing contract includes more than one gas plant product and the processing costs attributable to each product cannot be determined from the contract, you must propose an allocation procedure to MMS. You may use your proposed allocation procedure until MMS issues its determination. You are required to submit all relevant data to support your proposal. MMS will then determine the processing allowance based upon your proposal and any additional information MMS deems necessary. You may not take a processing allowance for the costs of processing lease production that is not royalty-bearing.

(4) If your payments for processing under an arm's-length contract are not based on a dollar per unit price, you must convert whatever consideration is paid to a dollar value equivalent for the purposes of this section.

(b) *Determining a processing allowance if you have a non-arm's-length contract or no contract.* (1) This paragraph applies if you have a non-arm's-length processing contract or no contract, including those situations where you perform processing for yourself.

(i) If you have a non-arm's-length contract or no contract, the processing allowance is based upon your reasonable actual costs of processing as provided in paragraph (b)(2) of this section.

(ii) All processing allowances deducted under a non-arm's-length or no-contract situation are subject to monitoring, review, audit, and adjustment. You must submit the actual cost information to support the allowance to MMS on Form MMS-4109, Gas Processing Allowance Summary Report, within 3 months after the end of the 12-month period for which the allowance applies. MMS may approve a longer time period. MMS will monitor the allowance deduction to ensure that deductions are reasonable and allowable. When necessary or appropriate, MMS may require you to modify your processing allowance.

(2) The processing allowance for non-arm's-length or no-contract situations is based upon your actual

costs for processing during the reporting period. Allowable costs include operating and maintenance expenses, overhead, and either depreciation and a return on undepreciated capital investment (in accordance with paragraph (b)(2)(iv)(A) of this section), or a cost equal to the initial depreciable investment in the processing plant multiplied by a rate of return in accordance with paragraph (b)(2)(iv)(B) of this section. Allowable capital costs are generally those costs for depreciable fixed assets (including costs of delivery and installation of capital equipment) that are an integral part of the processing plant.

(i) Allowable operating expenses include operations supervision and engineering, operations labor, fuel, utilities, materials, ad valorem property taxes, rent, supplies, and any other directly allocable and attributable operating expense that the lessee can document.

(ii) Allowable maintenance expenses include maintenance of the processing plant, maintenance of equipment, maintenance labor, and other directly allocable and attributable maintenance expenses that you can document.

(iii) Overhead directly attributable and allocable to the operation and maintenance of the processing plant is an allowable expense. State and Federal income taxes and severance taxes, including royalties, are not allowable expenses.

(iv) You may use either depreciation with a return on undepreciable capital investment or a return on depreciable capital investment. After you elect to use either method for a processing plant, you may not later elect to change to the other alternative without MMS approval.

(A) To compute depreciation, you may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves that the processing plant services, or a unit-of-production method. Once you make an election, you may not change methods without MMS approval. A change in ownership of a processing plant will not alter the depreciation schedule that the original processor/lessee established for purposes of the allowance calculation. However, for processing plants you or your affiliate purchase that do not have a previously claimed MMS depreciation schedule, you may treat the processing plant as a newly installed facility for depreciation purposes. A processing plant may be depreciated only once, regardless of whether there is a change in ownership. Equipment may not be depreciated below a reasonable salvage value. To compute a return on undepreciated capital investment, you must multiply the undepreciable capital investment in the processing plant by the rate of return determined under paragraph (b)(2)(v) of this section.

(B) To compute a return on depreciable capital investment, you must multiply the initial capital investment in the processing plant by the rate of return determined under paragraph (b)(2)(v) of this section. No allowance will be provided for depreciation. This alternative will apply only to plants first placed in service after March 1, 1988.

(v) The rate of return is the industrial rate associated with Standard and Poor's BBB rating. The rate of return is the monthly average rate as published in Standard and Poor's Bond Guide for the first month for which the allowance is applicable. The rate must be redetermined at the beginning of each subsequent calendar year.

(3) Your processing allowance under this paragraph (b) must be determined based upon a calendar year or other period if you and MMS agree to an alternative.

(4) The processing allowance for each gas plant product must be determined based on your reasonable and actual cost of processing the gas. You must base your allocation of costs to each gas plant product upon generally accepted accounting principles. You may not take an allowance for the costs of processing lease production that is not royalty-bearing.

(c) *Reporting your processing allowance.* (1) If MMS requests, you must submit all data used to determine your processing allowance. The data must be provided within a reasonable period of time, as MMS determines.

(2) You must report gas processing allowances as a separate entry on the Form MMS-2014. MMS may approve a different reporting procedure for allottee leases, and with lessor approval on tribal leases.

(d) *Adjusting incorrect processing allowances.* If for any month the gas processing allowance you are entitled to is less than the amount you took on Form MMS-2014, you are required to pay additional royalties, plus interest computed under 30 CFR 218.54 from the first day of the first month you deducted a processing allowance until the date you pay the royalties due. If the processing allowance you are entitled to is greater than the amount you took on Form MMS-2014, you are entitled to a credit. However, no interest will be paid on the overpayment.

(e) *Other processing cost determinations.* You must follow the provisions of this section to determine processing costs when establishing value using either a net-back valuation procedure or any other procedure that requires deduction of actual processing costs.

[64 FR 43515, Aug. 10, 1999, as amended at 73 FR 15891, Mar. 26, 2008]

**§ 206.181 How do I establish processing costs for dual accounting purposes when I do not process the gas?**



Where accounting for comparison (dual accounting) is required for gas production from a lease but neither you nor someone acting on your behalf processes the gas, and you have elected to perform actual dual accounting under §206.176, you must use the first applicable of the following methods to establish processing costs for dual accounting purposes:

- (a) The average of the costs established in your current arm's-length processing agreements for gas from the lease, provided that some gas has previously been processed under these agreements.
- (b) The average of the costs established in your current arm's-length processing agreements for gas from the lease, provided that the agreements are in effect for plants to which the lease is physically connected and under which gas from other leases in the field or area is being or has been processed.
- (c) A proposed comparable processing fee submitted to either the tribe and MMS (for tribal leases) or MMS (for allotted leases) with your supporting documentation submitted to MMS. If MMS does not take action on your proposal within 120 days, the proposal will be deemed to be denied and subject to appeal to the MMS Director under 30 CFR part 290.
- (d) Processing costs based on the regulations in §§206.179 and 206.180.

**Subpart F—Federal Coal**



**Source:** 54 FR 1523, Jan. 13, 1989, unless otherwise noted.

**§ 206.250 Purpose and scope.**



- (a) This subpart is applicable to all coal produced from Federal coal leases. The purpose of this subpart is to establish the value of coal produced for royalty purposes, of all coal from Federal leases consistent with the mineral leasing laws, other applicable laws and lease terms.
- (b) If the specific provisions of any statute or settlement agreement between the United States and a lessee resulting from administrative or judicial litigation, or any coal lease subject to the requirements of this subpart, are inconsistent with any regulation in this subpart then the statute, lease provision, or settlement shall govern to the extent of that inconsistency.
- (c) All royalty payments made to the Minerals Management Service (MMS) are subject to later audit and adjustment.

[54 FR 1523, Jan. 13, 1989, as amended at 61 FR 5479, Feb. 12, 1996; 67 FR 19111, Apr. 18, 2002]

**§ 206.251 Definitions.**



*Ad valorem lease* means a lease where the royalty due to the lessor is based upon a percentage of the amount or value of the coal.

*Allowance* means a deduction used in determining value for royalty purposes. Coal washing allowance means an allowance for the reasonable, actual costs incurred by the lessee for coal washing. Transportation allowance means an allowance for the reasonable, actual costs incurred by the lessee for moving coal to a point of sale or point of delivery remote from both the lease and mine or wash plant.

*Area* means a geographic region in which coal has similar quality and economic characteristics. Area boundaries are not officially designated and the areas are not necessarily named.

*Arm's-length contract* means a contract or agreement that has been arrived at in the marketplace between independent, nonaffiliated persons with opposing economic interests regarding that contract. For purposes of this subpart, two persons are affiliated if one person controls, is controlled by, or is under common control with another person. For purposes of this subpart, based on the instruments of ownership of the voting securities of an entity, or based on other forms of ownership:

- (a) Ownership in excess of 50 percent constitutes control;
- (b) Ownership of 10 through 50 percent creates a presumption of control; and
- (c) Ownership of less than 10 percent creates a presumption of noncontrol which MMS may rebut if it demonstrates actual or legal control, including the existence of interlocking directorates.

Notwithstanding any other provisions of this subpart, contracts between relatives, either by blood or by marriage, are not arm's-length contracts. The MMS may require the lessee to certify ownership control. To be considered arm's-length for any production month, a contract must meet the requirements of this definition for that production month as well as when the contract was executed.

*Audit* means a review, conducted in accordance with generally accepted accounting and auditing standards, of royalty payment compliance activities of lessees or other interest holders who pay royalties, rents, or bonuses on Federal leases.

*BLM* means the Bureau of Land Management of the Department of the Interior.

*Coal* means coal of all ranks from lignite through anthracite.

*Coal washing* means any treatment to remove impurities from coal. Coal washing may include, but is not limited to, operations such as flotation, air, water, or heavy media separation; drying; and related handling (or combination thereof).

*Contract* means any oral or written agreement, including amendments or revisions thereto, between two or more persons and enforceable by law that with due consideration creates an obligation.

*Gross proceeds* (for royalty payment purposes) means the total monies and other consideration accruing to a coal lessee for the production and disposition of the coal produced. Gross proceeds includes, but is not limited to, payments to the lessee for certain services such as crushing, sizing, screening, storing, mixing, loading, treatment with substances including chemicals or oils, and other preparation of the coal to the extent that the lessee is obligated to perform them at no cost to the Federal Government. Gross proceeds, as applied to coal, also includes but is not limited to reimbursements for royalties, taxes or fees, and other reimbursements. Tax reimbursements are part of the gross proceeds accruing to a lessee even though the Federal royalty interest may be exempt from taxation. Monies and other consideration, including the forms of consideration identified in this paragraph, to which a lessee is contractually or legally entitled but which it does not seek to collect through reasonable efforts are also part of gross proceeds.

*Lease* means any contract, profit-share arrangement, joint venture, or other agreement issued or approved by the United States for a Federal coal resource under a mineral leasing law that authorizes exploration for, development or extraction of, or removal of coal—or the land covered by that authorization, whichever is required by the context.

*Lessee* means any person to whom the United States issues a lease, and any person who has been assigned an obligation to make royalty or other payments required by the lease. This includes any person who has an interest in a lease as well as an operator or payor who has no interest in the lease but who has assumed the royalty payment responsibility.

*Like-quality coal* means coal that has similar chemical and physical characteristics.

*Marketable condition* means coal that is sufficiently free from impurities and otherwise in a condition that it will be accepted by a purchaser under a sales contract typical for that area.

*Mine* means an underground or surface excavation or series of excavations and the surface or underground support facilities that contribute directly or indirectly to mining, production, preparation, and handling of lease products.

*Net-back method* means a method for calculating market value of coal at the lease or mine. Under this method, costs of transportation, washing, handling, etc., are deducted from the ultimate proceeds received for the coal at the first point at which reasonable values for the coal may be determined by a sale pursuant to an arm's-length contract or by comparison to other sales of coal, to ascertain value at the mine.

*Net output* means the quantity of washed coal that a washing plant produces.

*Netting* is the deduction of an allowance from the sales value by reporting a one line net sales value, instead of correctly reporting the deduction as a separate line item on the Form MMS-4430.

*Person* means by individual, firm, corporation, association, partnership, consortium, or joint venture.

*Sales type code* means the contract type or general disposition (e.g., arm's-length or non-arm's-length) of production from the lease. The sales type code applies to the sales contract, or other disposition, and not to the arm's-length or non-arm's-length nature of a transportation or washing allowance.

*Spot market price* means the price received under any sales transaction when planned or actual deliveries span a short period of time, usually not exceeding one year.

[54 FR 1523, Jan. 13, 1989, as amended at 55 FR 35433, Aug. 30, 1990; 61 FR 5479, Feb. 12, 1996; 64 FR 43288, Aug. 10, 1999; 66 FR 45769, Aug. 30, 2001; 73 FR 15891, Mar. 26, 2008]

## § 206.252 Information collection.



[top](#)

The information collection requirements contained in this subpart have been approved by the Office of Management and Budget (OMB) under 44 U.S.C. 3501 *et seq.* The forms, filing date, and approved OMB control numbers are identified in 30 CFR 210—Forms and Reports.

[73 FR 15891, Mar. 26, 2008]

## § 206.253 Coal subject to royalties—general provisions.



[top](#)

(a) All coal (except coal unavoidably lost as determined by BLM under 43 CFR part 3400) from a Federal lease subject to this part is subject to royalty. This includes coal used, sold, or otherwise disposed of by the lessee on or off the lease.

(b) If a lessee receives compensation for unavoidably lost coal through insurance coverage or other arrangements, royalties at the rate specified in the lease are to be paid on the amount of compensation received for the coal. No royalty is due on insurance compensation received by the lessee for other losses.

(c) If waste piles or slurry ponds are reworked to recover coal, the lessee shall pay royalty at the rate specified in the lease at the time the recovered coal is used, sold, or otherwise finally disposed of. The royalty rate shall be that rate applicable to the production method used to initially mine coal in the waste pile or slurry pond; *i.e.*, underground mining method or surface mining method. Coal in waste pits or slurry ponds initially mined from Federal leases shall be allocated to such leases regardless of whether it is stored on Federal lands. The lessee shall maintain accurate records to determine to which individual Federal lease coal in the waste pit or slurry pond should be allocated. However, nothing in this section requires payment of a royalty on coal for which a royalty has already been paid.

[54 FR 1523, Jan. 13, 1989, as amended at 61 FR 5479, Feb. 12, 1996]

## § 206.254 Quality and quantity measurement standards for reporting and paying royalties.

[top](#)

For all leases subject to this subpart, the quantity of coal on which royalty is due shall be measured in short tons (of 2,000 pounds each) by methods prescribed by the BLM. Coal quantity information will be reported on appropriate forms required under 30 CFR part 210—Forms and Reports.

[54 FR 1523, Jan. 13, 1989, as amended at 57 FR 52720, Nov. 5, 1992; 66 FR 45769, Aug. 30, 2001; 73 FR 15891, Mar. 26, 2008]

#### **§ 206.255 Point of royalty determination.**

[top](#)

(a) For all leases subject to this subpart, royalty shall be computed on the basis of the quantity and quality of Federal coal in marketable condition measured at the point of royalty measurement as determined jointly by BLM and MMS.

(b) Coal produced and added to stockpiles or inventory does not require payment of royalty until such coal is later used, sold, or otherwise finally disposed of. MMS may ask BLM to increase the lease bond to protect the lessor's interest when BLM determines that stockpiles or inventory become excessive so as to increase the risk of degradation of the resource.

(c) The lessee shall pay royalty at a rate specified in the lease at the time the coal is used, sold, or otherwise finally disposed of, unless otherwise provided for at §206.256(d) of this subpart.

[54 FR 1523, Jan. 13, 1989, as amended at 61 FR 5480, Feb. 12, 1996]

#### **§ 206.256 Valuation standards for cents-per-ton leases.**

[top](#)

(a) This section is applicable to coal leases on Federal lands which provide for the determination of royalty on a cents-per-ton (or other quantity) basis.

(b) The royalty for coal from leases subject to this section shall be based on the dollar rate per ton prescribed in the lease. That dollar rate shall be applicable to the actual quantity of coal used, sold, or otherwise finally disposed of, including coal which is avoidably lost as determined by BLM pursuant to 43 CFR part 3400.

(c) For leases subject to this section, there shall be no allowances for transportation, removal of impurities, coal washing, or any other processing or preparation of the coal.

(d) When a coal lease is readjusted pursuant to 43 CFR part 3400 and the royalty valuation method changes from a cents-per-ton basis to an ad valorem basis, coal which is produced prior to the effective date of readjustment and sold or used within 30 days of the effective date of readjustment shall be valued pursuant to this section. All coal that is not used, sold, or otherwise finally disposed of within 30 days after the effective date of readjustment shall be valued pursuant to the provisions of §206.257 of this subpart, and royalties shall be paid at the royalty rate specified in the readjusted lease.

[54 FR 1523, Jan. 13, 1989, as amended at 61 FR 5480, Feb. 12, 1996]

#### **§ 206.257 Valuation standards for ad valorem leases.**

[top](#)

(a) This section is applicable to coal leases on Federal lands which provide for the determination of royalty as a percentage of the amount of value of coal (ad valorem). The value for royalty purposes of coal from such leases shall be the value of coal determined under this section, less applicable coal washing allowances and transportation allowances determined under §§206.258 through 206.262 of this subpart, or any allowance authorized by §206.265 of this subpart. The royalty due shall be equal to the value for royalty purposes multiplied by the royalty rate in the lease.

(b)(1) The value of coal that is sold pursuant to an arm's-length contract shall be the gross proceeds accruing to the lessee, except as provided in paragraphs (b)(2), (b)(3), and (b)(5) of this section. The lessee shall have the burden of demonstrating that its contract is arm's-length. The value which the lessee reports, for royalty purposes, is subject to monitoring, review, and audit.

(2) In conducting reviews and audits, MMS will examine whether the contract reflects the total consideration actually transferred either directly or indirectly from the buyer to the seller for the coal produced. If the contract does not reflect the total consideration, then the MMS may require that the coal sold pursuant to that contract be valued in accordance with paragraph (c) of this section. Value may not be based on less than the gross proceeds accruing to the lessee for the coal production, including the additional consideration.

(3) If the MMS determines that the gross proceeds accruing to the lessee pursuant to an arm's-length contract do not reflect the reasonable value of the production because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then MMS shall require that the coal production be valued pursuant to paragraph (c)(2) (ii), (iii), (iv), or (v) of this section, and in accordance with the notification requirements of paragraph (d)(3) of this section. When MMS determines that the value may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's reported coal value.

(4) The MMS may require a lessee to certify that its arm's-length contract provisions include all of the consideration to be paid by the buyer, either directly or indirectly, for the coal production.

(5) The value of production for royalty purposes shall not include payments received by the lessee pursuant to a contract which the lessee demonstrates, to MMS's satisfaction, were not part of the total consideration paid for the purchase of coal production.

(c)(1) The value of coal from leases subject to this section and which is not sold pursuant to an arm's-length contract shall be determined in accordance with this section.

(2) If the value of the coal cannot be determined pursuant to paragraph (b) of this section, then the value shall be determined through application of other valuation criteria. The criteria shall be considered in the following order, and the value shall be based upon the first applicable criterion:

(i) The gross proceeds accruing to the lessee pursuant to a sale under its non-arm's-length contract (or other disposition of produced coal by other than an arm's-length contract), provided that those gross proceeds are within the range of the gross proceeds derived from, or paid under, comparable arm's-length contracts between buyers and sellers neither of whom is affiliated with the lessee for sales, purchases, or other dispositions of like-quality coal produced in the area. In evaluating the comparability of arm's-length contracts for the purposes of these regulations, the following factors shall be considered: Price, time of execution, duration, market or markets served, terms, quality of coal, quantity, and such other factors as may be appropriate to reflect the value of the coal;

(ii) Prices reported for that coal to a public utility commission;

(iii) Prices reported for that coal to the Energy Information Administration of the Department of Energy;

(iv) Other relevant matters including, but not limited to, published or publicly available spot market prices, or information submitted by the lessee concerning circumstances unique to a particular lease operation or the saleability of certain types of coal;

(v) If a reasonable value cannot be determined using paragraphs (c)(2) (i), (ii), (iii), or (iv) of this section, then a net-back method or any other reasonable method shall be used to determine value.

(3) When the value of coal is determined pursuant to paragraph (c)(2) of this section, that value determination shall be consistent with the provisions contained in paragraph (b)(5) of this section.

(d)(1) Where the value is determined pursuant to paragraph (c) of this section, that value does not require MMS's prior approval. However, the lessee shall retain all data relevant to the determination of royalty value. Such data shall be subject to review and audit, and MMS will direct a lessee to use a different value if it determines that the reported value is inconsistent with the requirements of these regulations.

(2) Any Federal lessee will make available upon request to the authorized MMS or State representatives, to the Inspector General of the Department of the Interior or other persons authorized to receive such information, arm's-length sales value and sales quantity data for like-quality coal sold,

purchased, or otherwise obtained by the lessee from the area.

(3) A lessee shall notify MMS if it has determined value pursuant to paragraphs (c)(2) (ii), (iii), (iv), or (v) of this section. The notification shall be by letter to the Associate Director for Minerals Revenue Management of his/her designee. The letter shall identify the valuation method to be used and contain a brief description of the procedure to be followed. The notification required by this section is a one-time notification due no later than the month the lessee first reports royalties on the Form MMS-4430 using a valuation method authorized by paragraphs (c)(2) (ii), (iii), (iv), or (v) of this section, and each time there is a change in a method under paragraphs (c)(2) (iv) or (v) of this section.

(e) If MMS determines that a lessee has not properly determined value, the lessee shall be liable for the difference, if any, between royalty payments made based upon the value it has used and the royalty payments that are due based upon the value established by MMS. The lessee shall also be liable for interest computed pursuant to 30 CFR 218.202. If the lessee is entitled to a credit, MMS will provide instructions for the taking of that credit.

(f) The lessee may request a value determination from MMS. In that event, the lessee shall propose to MMS a value determination method, and may use that method in determining value for royalty purposes until MMS issues its decision. The lessee shall submit all available data relevant to its proposal. The MMS shall expeditiously determine the value based upon the lessee's proposal and any additional information MMS deems necessary. That determination shall remain effective for the period stated therein. After MMS issues its determination, the lessee shall make the adjustments in accordance with paragraph (e) of this section.

(g) Notwithstanding any other provisions of this section, under no circumstances shall the value for royalty purposes be less than the gross proceeds accruing to the lessee for the disposition of produced coal less applicable provisions of paragraph (b)(5) of this section and less applicable allowances determined pursuant to §§206.258 through 206.262 and §206.265 of this subpart.

(h) The lessee is required to place coal in marketable condition at no cost to the Federal Government. Where the value established under this section is determined by a lessee's gross proceeds, that value shall be increased to the extent that the gross proceeds has been reduced because the purchaser, or any other person, is providing certain services, the cost of which ordinarily is the responsibility of the lessee to place the coal in marketable condition.

(i) Value shall be based on the highest price a prudent lessee can receive through legally enforceable claims under its contract. Absent contract revision or amendment, if the lessee fails to take proper or timely action to receive prices or benefits to which it is entitled, it must pay royalty at a value based upon that obtainable price or benefit. Contract revisions or amendments shall be in writing and signed by all parties to an arm's-length contract, and may be retroactively applied to value for royalty purposes for a period not to exceed two years, unless MMS approves a longer period. If the lessee makes timely application for a price increase allowed under its contract but the purchaser refuses, and the lessee takes reasonable measures, which are documented, to force purchaser compliance, the lessee will owe no additional royalties unless or until monies or consideration resulting from the price increase are received. This paragraph shall not be construed to permit a lessee to avoid its royalty payment obligation in situations where a purchaser fails to pay, in whole or in part or timely, for a quantity of coal.

(j) Notwithstanding any provision in these regulations to the contrary, no review, reconciliation, monitoring, or other like process that results in a redetermination by MMS of value under this section shall be considered final or binding as against the Federal Government or its beneficiaries until the audit period is formally closed.

(k) Certain information submitted to MMS to support valuation proposals, including transportation, coal washing, or other allowances under §206.265 of this subpart, is exempted from disclosure by the Freedom of Information Act, 5 U.S.C. 522. Any data specified by the Act to be privileged, confidential, or otherwise exempt shall be maintained in a confidential manner in accordance with applicable law and regulations. All requests for information about determinations made under this part are to be submitted in accordance with the Freedom of Information Act regulation of the Department of the Interior, 43 CFR part 2.

[54 FR 1523, Jan. 13, 1989, as amended at 55 FR 35433, Aug. 30, 1990; 57 FR 52720, Nov. 5, 1992; 61 FR 5480, Feb. 12, 1996; 66 FR 45769, Aug. 30, 2001]

#### **§ 206.258 Washing allowances—general.**



[top](#)

(a) For ad valorem leases subject to §206.257 of this subpart, MMS shall, as authorized by this section, allow a deduction in determining value for royalty purposes for the reasonable, actual costs incurred to wash coal, unless the value determined pursuant to §206.257 of this subpart was based upon like-quality unwashed coal. Under no circumstances will the authorized washing allowance and the transportation allowance reduce the value for royalty purposes to zero.

(b) If MMS determines that a lessee has improperly determined a washing allowance authorized by this section, then the lessee shall be liable for any additional royalties, plus interest determined in accordance with 30 CFR 218.202, or shall be entitled to a credit without interest.

(c) Lessees shall not disproportionately allocate washing costs to Federal leases.

(d) No cost normally associated with mining operations and which are necessary for placing coal in marketable condition shall be allowed as a cost of washing.

(e) Coal washing costs shall only be recognized as allowances when the washed coal is sold and royalties are reported and paid.

[54 FR 1523, Jan. 13, 1989, as amended at 61 FR 5480, Feb. 12, 1996; 64 FR 43288, Aug. 10, 1999]

#### § 206.259 Determination of washing allowances.



[top](#)

(a) *Arm's-length contracts.* (1) For washing costs incurred by a lessee under an arm's-length contract, the washing allowance shall be the reasonable actual costs incurred by the lessee for washing the coal under that contract, subject to monitoring, review, audit, and possible future adjustment. The lessee shall have the burden of demonstrating that its contract is arm's-length. MMS' prior approval is not required before a lessee may deduct costs incurred under an arm's-length contract. The lessee must claim a washing allowance by reporting it as a separate line entry on the Form MMS-4430.

(2) In conducting reviews and audits, MMS will examine whether the contract reflects more than the consideration actually transferred either directly or indirectly from the lessee to the washer for the washing. If the contract reflects more than the total consideration paid, then the MMS may require that the washing allowance be determined in accordance with paragraph (b) of this section.

(3) If the MMS determines that the consideration paid pursuant to an arm's-length washing contract does not reflect the reasonable value of the washing because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then MMS shall require that the washing allowance be determined in accordance with paragraph (b) of this section. When MMS determines that the value of the washing may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's washing costs.

(4) Where the lessee's payments for washing under an arm's-length contract are not based on a dollar-per-unit basis, the lessee shall convert whatever consideration is paid to a dollar value equivalent. Washing allowances shall be expressed as a cost per ton of coal washed.

(b) *Non-arm's-length or no contract.* (1) If a lessee has a non-arm's-length contract or has no contract, including those situations where the lessee performs washing for itself, the washing allowance will be based upon the lessee's reasonable actual costs. All washing allowances deducted under a non-arm's-length or no contract situation are subject to monitoring, review, audit, and possible future adjustment. The lessee must claim a washing allowance by reporting it as a separate line entry on the Form MMS-4430. When necessary or appropriate, MMS may direct a lessee to modify its estimated or actual washing allowance.

(2) The washing allowance for non-arm's-length or no contract situations shall be based upon the lessee's actual costs for washing during the reported period, including operating and maintenance expenses, overhead, and either depreciation and a return on undepreciated capital investment in accordance with paragraph (b)(2)(iv)(A) of this section, or a cost equal to the depreciable investment in the wash plant multiplied by the rate of return in accordance with paragraph (b)(2)(iv)(B) of this section. Allowable capital costs are generally those for depreciable fixed assets (including costs of delivery and installation of capital equipment) which are an integral part of the wash plant.

(i) Allowable operating expenses include: Operations supervision and engineering; operations labor; fuel; utilities; materials; ad valorem property taxes, rent; supplies; and any other directly allocable and attributable operating expense which the lessee can document.

(ii) Allowable maintenance expenses include: Maintenance of the wash plant; maintenance of equipment; maintenance labor; and other directly allocable and attributable maintenance expenses which the lessee can document.

(iii) Overhead attributable and allocable to the operation and maintenance of the wash plant is an allowable expense. State and Federal income taxes and severance taxes, including royalties, are not allowable expenses.

(iv) A lessee may use either paragraph (b)(2)(iv)(A) or (B) of this section. After a lessee has elected to use either method for a wash plant, the lessee may not later elect to change to the other alternative without approval of the MMS.

(A) To compute depreciation, the lessee may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves which the wash plant services, whichever is appropriate, or a unit of production method. After an election is made, the lessee may not change methods without MMS approval. A change in ownership of a wash plant shall not alter the depreciation schedule established by the original operator/lessee for purposes of the allowance calculation. With or without a change in ownership, a wash plant shall be depreciated only once. Equipment shall not be depreciated below a reasonable salvage value.

(B) The MMS shall allow as a cost an amount equal to the allowable capital investment in the wash plant multiplied by the rate of return determined pursuant to paragraph (b)(2)(v) of this section. No allowance shall be provided for depreciation. This alternative shall apply only to plants first placed in service or acquired after March 1, 1989.

(v) The rate of return must be the industrial rate associated with Standard and Poor's BBB rating. The rate of return must be the monthly average rate as published in Standard and Poor's Bond Guide for the first month for which the allowance is applicable. The rate must be redetermined at the beginning of each subsequent calendar year.

(3) The washing allowance for coal shall be determined based on the lessee's reasonable and actual cost of washing the coal. The lessee may not take an allowance for the costs of washing lease production that is not royalty bearing.

(c) *Reporting requirements* —(1) *Arm's-length contracts.* (i) The lessee must notify MMS of an allowance based on incurred costs by using a separate line entry on the Form MMS-4430.

(ii) The MMS may require that a lessee submit arm's-length washing contracts and related documents. Documents shall be submitted within a reasonable time, as determined by MMS.

(2) *Non-arm's-length or no contract.* (i) The lessee must notify MMS of an allowance based on the incurred costs by using a separate line entry on the Form MMS-4430.

(ii) For new washing facilities or arrangements, the lessee's initial washing deduction shall include estimates of the allowable coal washing costs for the applicable period. Cost estimates shall be based upon the most recently available operations data for the washing system or, if such data are not available, the lessee shall use estimates based upon industry data for similar washing systems.

(iii) Upon request by MMS, the lessee shall submit all data used to prepare the allowance deduction. The data shall be provided within a reasonable period of time, as determined by MMS.

(d) *Interest and assessments.* (1) If a lessee nets a washing allowance on the Form MMS-4430, then the lessee shall be assessed an amount up to 10 percent of the allowance netted not to exceed \$250 per lease sales type code per sales period.

(2) If a lessee erroneously reports a washing allowance which results in an underpayment of royalties, interest shall be paid on the amount of that underpayment.

(3) Interest required to be paid by this section shall be determined in accordance with 30 CFR 218.202.

(e) *Adjustments.* (1) If the actual coal washing allowance is less than the amount the lessee has taken on Form MMS-4430 for each month during the allowance reporting period, the lessee shall pay additional royalties due plus interest computed under 30 CFR 218.202 from the date when the lessee took the deduction to the date the lessee repays the difference to MMS. If the actual washing allowance is greater than the amount the lessee has taken on Form MMS-4430 for each month during the allowance reporting period, the lessee shall be entitled to a credit without interest.

(2) The lessee must submit a corrected Form MMS-4430 to reflect actual costs, together with any payment, in accordance with instructions provided by MMS.

(f) *Other washing cost determinations.* The provisions of this section shall apply to determine washing costs when establishing value using a net-back valuation procedure or any other procedure that requires deduction of washing costs.

[54 FR 1523, Jan. 13, 1989, as amended at 57 FR 52720, Nov. 5, 1992; 61 FR 5480, Feb. 12, 1996; 64 FR 43288, Aug. 10, 1999; 66 FR 45769, Aug. 30, 2001; 73 FR 15891, Mar. 26, 2008]

#### **§ 206.260 Allocation of washed coal.**



(a) When coal is subjected to washing, the washed coal must be allocated to the leases from which it was extracted.

(b) When the net output of coal from a washing plant is derived from coal obtained from only one lease, the quantity of washed coal allocable to the lease will be based on the net output of the washing plant.

(c) When the net output of coal from a washing plant is derived from coal obtained from more than one lease, unless determined otherwise by BLM, the quantity of net output of washed coal allocable to each lease will be based on the ratio of measured quantities of coal delivered to the washing plant and washed from each lease compared to the total measured quantities of coal delivered to the washing plant and washed.

#### **§ 206.261 Transportation allowances—general.**



(a) For ad valorem leases subject to §206.257 of this subpart, where the value for royalty purposes has been determined at a point remote from the lease or mine, MMS shall, as authorized by this section, allow a deduction in determining value for royalty purposes for the reasonable, actual costs incurred to:

(1) Transport the coal from a Federal lease to a sales point which is remote from both the lease and mine; or

(2) Transport the coal from a Federal lease to a wash plant when that plant is remote from both the lease and mine and, if applicable, from the wash plant to a remote sales point. In-mine transportation costs shall not be included in the transportation allowance.

(b) Under no circumstances will the authorized washing allowance and the transportation allowance reduce the value for royalty purposes to zero.

(c)(1) When coal transported from a mine to a wash plant is eligible for a transportation allowance in accordance with this section, the lessee is not required to allocate transportation costs between the quantity of clean coal output and the rejected waste material. The transportation allowance shall be authorized for the total production which is transported. Transportation allowances shall be expressed as a cost per ton of cleaned coal transported.

(2) For coal that is not washed at a wash plant, the transportation allowance shall be authorized for the total production which is transported. Transportation allowances shall be expressed as a cost per ton of coal transported.

(3) Transportation costs shall only be recognized as allowances when the transported coal is sold and royalties are reported and paid.

(d) If, after a review and/or audit, MMS determines that a lessee has improperly determined a transportation allowance authorized by this section, then the lessee shall pay any additional royalties, plus interest, determined in accordance with 30 CFR 218.202, or shall be entitled to a credit, without interest.

(e) Lessees shall not disproportionately allocate transportation costs to Federal leases.

[54 FR 1523, Jan. 13, 1989, as amended at 61 FR 5481, Feb. 12, 1996; 64 FR 43288, Aug. 10, 1999]

## § 206.262 Determination of transportation allowances.



(a) *Arm's-length contracts.* (1) For transportation costs incurred by a lessee pursuant to an arm's-length contract, the transportation allowance shall be the reasonable, actual costs incurred by the lessee for transporting the coal under that contract, subject to monitoring, review, audit, and possible future adjustment. The lessee shall have the burden of demonstrating that its contract is arm's-length. The lessee must claim a transportation allowance by reporting it as a separate line entry on the Form MMS-4430.

(2) In conducting reviews and audits, MMS will examine whether the contract reflects more than the consideration actually transferred either directly or indirectly from the lessee to the transporter for the transportation. If the contract reflects more than the total consideration paid, then the MMS may require that the transportation allowance be determined in accordance with paragraph (b) of this section.

(3) If the MMS determines that the consideration paid pursuant to an arm's-length transportation contract does not reflect the reasonable value of the transportation because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then MMS shall require that the transportation allowance be determined in accordance with paragraph (b) of this section. When MMS determines that the value of the transportation may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's transportation costs.

(4) Where the lessee's payments for transportation under an arm's-length contract are not based on a dollar-per-unit basis, the lessee shall convert whatever consideration is paid to a dollar value equivalent for the purposes of this section.

(b) *Non-arm's-length or no contract* — (1) If a lessee has a non-arm's-length contract or has no contract, including those situations where the lessee performs transportation services for itself, the transportation allowance will be based upon the lessee's reasonable actual costs. All transportation allowances deducted under a non-arm's-length or no contract situation are subject to monitoring, review, audit, and possible future adjustment. The lessee must claim a transportation allowance by reporting it as a separate line entry on the Form MMS-4430. When necessary or appropriate, MMS may direct a lessee to modify its estimated or actual transportation allowance deduction.

(2) The transportation allowance for non-arm's-length or no-contract situations shall be based upon the lessee's actual costs for transportation during the reporting period, including operating and maintenance expenses, overhead, and either depreciation and a return on undepreciated capital investment in accordance with paragraph (b)(2)(iv)(A) of this section, or a cost equal to the depreciable investment in the transportation system multiplied by the rate of return in accordance with paragraph (b)(2)(iv)(B) of this section. Allowable capital costs are generally those for depreciable fixed assets (including costs of delivery and installation of capital equipment) which are an integral part of the transportation system.

(i) Allowable operating expenses include: Operations supervision and engineering; operations labor; fuel; utilities; materials; ad valorem property taxes; rent; supplies; and any other directly allocable and attributable operating expense which the lessee can document.

(ii) Allowable maintenance expenses include: Maintenance of the transportation system; maintenance of equipment; maintenance labor; and other directly allocable and attributable maintenance expenses which the lessee can document.

(iii) Overhead attributable and allocable to the operation and maintenance of the transportation system is an allowable expense. State and Federal income taxes and severance taxes and other fees, including royalties, are not allowable expenses.

(iv) A lessee may use either paragraph (b)(2)(iv)(A) or paragraph (b)(2)(iv)(B) of this section. After a lessee has elected to use either method for a transportation system, the lessee may not later elect to change to the other alternative without approval of the MMS.

(A) To compute depreciation, the lessee may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves which the transportation system services, whichever is appropriate, or a unit of production method. After an election is made, the lessee may not change methods without MMS approval. A change in ownership of a transportation system shall not alter the depreciation schedule established by the original transporter/lessee for purposes of the allowance

calculation. With or without a change in ownership, a transportation system shall be depreciated only once. Equipment shall not be depreciated below a reasonable salvage value.

(B) The MMS shall allow as a cost an amount equal to the allowable capital investment in the transportation system multiplied by the rate of return determined pursuant to paragraph (b)(2)(B)(v) of this section. No allowance shall be provided for depreciation. This alternative shall apply only to transportation facilities first placed in service or acquired after March 1, 1989.

(v) The rate of return must be the industrial rate associated with Standard and Poor's BBB rating. The rate of return must be the monthly average rate as published in Standard and Poor's Bond Guide for the first month for which the allowance is applicable. The rate must be redetermined at the beginning of each subsequent calendar year.

(3) A lessee may apply to MMS for exception from the requirement that it compute actual costs in accordance with paragraphs (b)(1) and (b)(2) of this section. MMS will grant the exception only if the lessee has a rate for the transportation approved by a Federal agency or by a State regulatory agency (for Federal leases). MMS shall deny the exception request if it determines that the rate is excessive as compared to arm's-length transportation charges by systems, owned by the lessee or others, providing similar transportation services in that area. If there are no arm's-length transportation charges, MMS shall deny the exception request if:

(i) No Federal or State regulatory agency costs analysis exists and the Federal or State regulatory agency, as applicable, has declined to investigate under MMS timely objections upon filing; and

(ii) The rate significantly exceeds the lessee's actual costs for transportation as determined under this section.

(c) *Reporting requirements*—(1) *Arm's-length contracts*. (i) The lessee must notify MMS of an allowance based on incurred costs by using a separate line entry on the Form MMS-4430.

(ii) The MMS may require that a lessee submit arm's-length transportation contracts, production agreements, operating agreements, and related documents. Documents shall be submitted within a reasonable time, as determined by MMS.

(2) *Non-arm's-length or no contract*—(i) The lessee must notify MMS of an allowance based on the incurred costs by using a separate line entry on Form MMS-4430.

(ii) For new transportation facilities or arrangements, the lessee's initial deduction shall include estimates of the allowable coal transportation costs for the applicable period. Cost estimates shall be based upon the most recently available operations data for the transportation system or, if such data are not available, the lessee shall use estimates based upon industry data for similar transportation systems.

(iii) Upon request by MMS, the lessee shall submit all data used to prepare the allowance deduction. The data shall be provided within a reasonable period of time, as determined by MMS.

(iv) If the lessee is authorized to use its Federal- or State-agency-approved rate as its transportation cost in accordance with paragraph (b)(3) of this section, it shall follow the reporting requirements of paragraph (c)(1) of this section.

(d) *Interest and assessments*. (1) If a lessee nets a transportation allowance on Form MMS-4430, the lessee shall be assessed an amount of up to 10 percent of the allowance netted not to exceed \$250 per lease sales type code per sales period.

(2) If a lessee erroneously reports a transportation allowance which results in an underpayment of royalties, interest shall be paid on the amount of that underpayment.

(3) Interest required to be paid by this section shall be determined in accordance with 30 CFR 218.202.

(e) *Adjustments*. (1) If the actual coal transportation allowance is less than the amount the lessee has taken on Form MMS-4430 for each month during the allowance reporting period, the lessee shall pay additional royalties due plus interest computed under 30 CFR 218.202 from the date when the lessee took the deduction to the date the lessee repays the difference to MMS. If the actual transportation allowance is greater than amount the lessee has taken on Form MMS-4430 for each month during the allowance reporting period, the lessee shall be entitled to a credit without interest.

(2) The lessee must submit a corrected Form MMS-4430 to reflect actual costs, together with any payments, in accordance with instructions provided by MMS.

(f) *Other transportation cost determinations.* The provisions of this section shall apply to determine transportation costs when establishing value using a net-back valuation procedure or any other procedure that requires deduction of transportation costs.

[54 FR 1523, Jan. 13, 1989, as amended at 57 FR 41864, Sept. 14, 1992; 57 FR 52720, Nov. 5, 1992; 61 FR 5481, Feb. 12, 1996; 64 FR 43288, Aug. 10, 1999; 66 FR 45769, Aug. 30, 2001; 73 FR 15891, Mar. 26, 2008]

#### **§ 206.263 [Reserved]**



#### **§ 206.264 In-situ and surface gasification and liquefaction operations.**



If an ad valorem Federal coal lease is developed by in-situ or surface gasification or liquefaction technology, the lessee shall propose the value of coal for royalty purposes to MMS. The MMS will review the lessee's proposal and issue a value determination. The lessee may use its proposed value until MMS issues a value determination.

[54 FR 1523, Jan. 13, 1989, as amended at 65 FR 43289, Aug. 10, 1999]

#### **§ 206.265 Value enhancement of marketable coal.**



If, prior to use, sale, or other disposition, the lessee enhances the value of coal after the coal has been placed in marketable condition in accordance with §206.257(h) of this subpart, the lessee shall notify MMS that such processing is occurring or will occur. The value of that production shall be determined as follows:

(a) A value established for the feedstock coal in marketable condition by application of the provisions of §206.257(c)(2)(i-iv) of this subpart; or,

(b) In the event that a value cannot be established in accordance with subsection (a), then the value of production will be determined in accordance with §206.257(c)(2)(v) of this subpart and the value shall be the lessee's gross proceeds accruing from the disposition of the enhanced product, reduced by MMS-approved processing costs and procedures including a rate of return on investment equal to two times the Standard and Poor's BBB bond rate applicable under §206.259(b)(2)(v) of this subpart.

### **Subpart G—Other Solid Minerals**



#### **§ 206.301 Value basis for royalty computation.**



(a) The gross value for royalty purposes shall be the sale or contract unit price times the number of units sold, *Provided, however,* That where the authorized officer determines:

(1) That a contract of sale or other business arrangement between the lessee and a purchaser of some or all of the commodities produced from the lease is not a bona fide transaction between independent parties because it is based in whole or in part upon considerations other than the value of the commodities, or

(2) That no bona fide sales price is received for some or all of such commodities because the lessee is consuming them, the authorized officer shall determine their gross value, taking into account: (i) All prices received by the lessee in all bona fide transactions, (ii) Prices paid for commodities of like quality produced from the same general area, and (iii) Such other relevant factors as the authorized officer may

deem appropriate; and *Provided further*, That in a situation where an estimated value is used, the authorized officer shall require the payment of such additional royalties, or allow such credits or refunds as may be necessary to adjust royalty payment to reflect the actual gross value.

(b) The lessee is required to certify that the values reported for royalty purposes are bona fide sales not involving considerations other than the sale of the mineral, and he may be required by the authorized officer to supply supporting information.

[43 FR 10341, Mar. 13, 1978. Redesignated at 48 FR 36588, Aug. 12, 1983, and amended at 48 FR 44795, Sept. 30, 1983. Further redesignated at 51 FR 15212, Apr. 22, 1986. Redesignated at 53 FR 39461, Oct. 7, 1988]

## Subpart H—Geothermal Resources



[top](#)

**Source:** 72 FR 24459, May 2, 2007, unless otherwise noted.

### § 206.350 What is the purpose of this subpart?



[top](#)

(a) This subpart applies to all geothermal resources produced from Federal geothermal leases issued pursuant to the Geothermal Steam Act of 1970 (GSA), as amended by the Energy Policy Act of 2005 (EPAct) (30 U.S.C. 1001 *et seq.*). The purpose of this subpart is to prescribe how to calculate royalties and direct use fees for geothermal production.

(b) The MMS may audit and adjust all royalty and fee payments.

(c) In some cases, the regulations in this subpart may be inconsistent with a statute, settlement agreement, written agreement, or lease provision. If this happens, the statute, settlement agreement, written agreement, or lease provision will govern to the extent of the inconsistency. For purposes of this paragraph, the following definitions apply:

(1) "Settlement agreement" means a settlement agreement between the United States and a lessee resulting from administrative or judicial litigation.

(2) "Written agreement" means a written agreement between the lessee and the MMS Director or Assistant Secretary, Land and Minerals Management of the Department of the Interior that:

(i) Establishes a method to determine the royalty from any lease that MMS expects at least would approximate the value or royalty established under this subpart; and

(ii) Includes a value or gross proceeds determination under §206.364 of this subpart.

### § 206.351 What definitions apply to this subpart?



[top](#)

For purposes of this subpart, the following terms have the meanings indicated.

**Affiliate** means a person who controls, is controlled by, or is under common control with another person. For purposes of this subpart:

(1) Ownership or common ownership of more than 50 percent of the voting securities, or instruments of ownership, or other forms of ownership, of another person constitutes control. Ownership of less than 10 percent constitutes a presumption of noncontrol that MMS may rebut.

(2) If there is ownership or common ownership of 10 through 50 percent of the voting securities, or instruments of ownership, or other forms of ownership of another person, MMS will consider the following factors in determining whether there is control under the circumstances of a particular case:

- (i) The extent to which there are common officers or directors;
  - (ii) With respect to the voting securities, or instruments of ownership, or other forms of ownership: the percentage of ownership or common ownership, the relative percentage of ownership or common ownership compared to the percentage(s) of ownership by other persons, whether a person is the greatest single owner, or whether there is an opposing voting bloc of greater ownership;
  - (iii) Operation of a lease, plant, pipeline, or other facility;
  - (iv) The extent of participation by other owners in operations and day-to-day management of a lease, plant, pipeline, or other facility; and
  - (v) Other evidence of power to exercise control over or common control with another person.
- (3) Regardless of any percentage of ownership or common ownership, relatives, either by blood or marriage, are affiliates.

*Allowance* means a deduction in determining value for royalty purposes.

*Arm's-length contract* means a contract or agreement between independent persons who are not affiliates and who have opposing economic interests regarding that contract. To be considered arm's length for any production month, a contract must satisfy this definition for that month, as well as when the contract was executed.

*Audit* means a review, conducted in accordance with generally accepted accounting and auditing standards, of royalty or fee payment compliance activities of lessees or other interest holders who pay royalties, fees, rents, or bonuses on Federal geothermal leases.

*Byproducts* means minerals (exclusive of oil, hydrocarbon gas, and helium), found in solution or in association with geothermal steam, that no person would extract and produce by themselves because they are worth less than 75 percent of the value of the geothermal steam or because extraction and production would be too difficult.

*Byproduct recovery facility* means a facility where byproducts are placed in marketable condition.

*Byproduct transportation allowance* means an allowance for the reasonable, actual costs of moving byproducts to a point of sale or delivery off the lease, unit area, or communitized area, or away from a byproduct recovery facility. The byproduct transportation allowance does not include gathering costs. You must report a byproduct transportation allowance as a separate discrete field on the Form MMS-2014.

*Class I lease* means:

- (1) A lease that BLM issued before August 8, 2005, for which the lessee has not converted the royalty rate terms under 43 CFR 3212.25; or
- (2) A lease that BLM issued in response to an application that was pending on August 8, 2005, for which the lessee has not made an election under 43 CFR 3200.8(b).

*Class II lease* means:

A lease that BLM issued after August 8, 2005, except for a lease issued in response to an application that was pending on August 8, 2005, for which the lessee does not make an election under 43 CFR 3200.8(b).

*Class III lease* means:

A lease that BLM issued before August 8, 2005, for which the lessee has converted to the royalty rate or direct use fee terms under 43 CFR 3212.25.

*Commercial production or generation of electricity* means generation of electricity that is sold or is subject to sale, including the electricity or energy that is reasonably required to produce the resource used in production of electricity for sale or to convert geothermal energy into electrical energy for sale.

*Contract* means any oral or written agreement, including amendments or revisions thereto, between two

or more persons and enforceable by law that with due consideration creates an obligation.

*Deduction* means a subtraction the lessee uses to determine the value of geothermal resources produced from a Class I lease that the lessee uses to generate electricity.

*Delivered electricity* means the amount of electricity in kilowatt-hours delivered to the purchaser.

*Direct use* means the utilization of geothermal resources for commercial, residential, agricultural, public facilities, or other energy needs, other than the commercial production or generation of electricity.

*Direct use facility* means a facility that uses the heat or other energy of the geothermal resource for direct use purposes.

*Electrical facility* means a power plant or other facility that uses a geothermal resource to generate electricity.

*Field* means the land surface vertically projected over a subsurface geothermal reservoir encompassing at least the outermost boundaries of all geothermal accumulations known to be within that reservoir. Geothermal fields are usually given names and their official boundaries are often designated by regulatory agencies in the respective States in which the fields are located.

*Gathering* means the movement of lease production from the wellhead to the point of utilization.

*Generating deduction* means a deduction for the lessee's reasonable, actual costs of generating plant tailgate electricity.

*Geothermal resources* means:

- (1) All products of geothermal processes, including indigenous steam, hot water, and hot brines;
- (2) Steam and other gases, hot water, and hot brines resulting from water, gas, or other fluids artificially introduced into geothermal formations;
- (3) Heat or other associated energy found in geothermal formations; and
- (4) Any byproducts.

*Gross proceeds* (for royalty payment purposes) means the total monies and other consideration accruing to a geothermal lessee for the sale of electricity or geothermal resource. Gross proceeds includes, but is not limited to:

- (1) Payments to the lessee for certain services such as effluent injection, field operation and maintenance, drilling or workover of wells, or field gathering to the extent that the lessee is obligated to perform such functions at no cost to the Federal Government;
- (2) Reimbursements for production taxes and other taxes. Tax reimbursements are part of gross proceeds accruing to a lessee even though the Federal royalty interest may be exempt from taxation; and
- (3) Any monies and other consideration, including the forms of consideration identified in this paragraph, to which a lessee is contractually or legally entitled but which it does not seek to collect through reasonable efforts.

*Lease* means a geothermal lease issued under the authority of the GSA, unless the context indicates otherwise.

*Lessee (you)* means any person to whom the United States issues a geothermal lease, and any person who has been assigned an obligation to make royalty, fee, or other payments required by the lease. This includes any person who has an interest in a geothermal lease as well as an operator or payor who has no interest in the lease but who has assumed the royalty, fee, or other payment responsibility. This also includes any affiliate of the lessee that uses the geothermal resource to generate electricity, in a direct use process, or to recover byproducts, or any affiliate that sells or transports lease production.

*Marketable condition* means lease products that are sufficiently free from impurities and otherwise in a condition that they will be accepted by a purchaser under a sales contract typical for the disposition from

the field or area of such lease products.

*Person* means any individual, firm, corporation, association, partnership, consortium, or joint venture (when established as a separate entity).

*Plant parasitic electricity* means electricity used to operate a power plant that is used for commercial production or generation of electricity.

*Plant tailgate electricity* means the amount of electricity in kilowatt-hours generated by a power plant exclusive of plant parasitic electricity, but inclusive of any electricity generated by the power plant and returned to the lease for lease operations. Plant tailgate electricity should be measured at, or calculated for, the high voltage side of the transformer in the plant switchyard.

*Point of utilization* means the power plant or direct use facility in which the geothermal resource is utilized.

*Public purpose* means a program carried out by a State, tribal, or local government for the purpose of providing facilities or services for the benefit of the public in connection with, but not limited to, public health, safety or welfare, other than the commercial generation of electricity. Use of lands or facilities for habitation, cultivation, trade or manufacturing is permissible only when necessary for and integral to ( *i.e.* , an essential part of) the public purpose.

*Public safety or welfare* means a program carried out or promoted by a public agency for public purposes involving, directly or indirectly, protection, safety, and law enforcement activities, and the criminal justice system of a given political area. Public safety or welfare may include, but is not limited to, programs carried out by:

- (1) Public police departments;
- (2) Sheriffs' offices;
- (3) The courts;
- (4) Penal and correctional institutions (including juvenile facilities);
- (5) State and local civil defense organizations; and
- (6) Fire departments and rescue squads (including volunteer fire departments and rescue squads supported in whole or in part with public funds).

*Reasonable alternative fuel* means a conventional fuel (such as coal, oil, gas, or wood) that would normally be used as a source of heat in direct use operations.

*Secretary* means the Secretary of the Interior or any person duly authorized to exercise the powers vested in that office.

*Transmission deduction* means a deduction for the lessee's reasonable actual costs incurred to wheel or transmit the electricity from the lessee's power plant to the purchaser's delivery point.

*Wheeling* means the transmission of electricity from a power plant to the point of delivery.

#### **§ 206.352 How do I calculate the royalty due on geothermal resources used for commercial production or generation of electricity?**



[top](#)

(a) If you sold geothermal resources produced from a Class I, II, or III lease at arm's length that the purchaser uses to generate electricity, then the royalty on the geothermal resources is the gross proceeds accruing to you from the sale of the geothermal resource to the arm's-length purchaser multiplied by either:

- (1) The royalty rate in your lease; or
- (2) The royalty rate that BLM prescribes or calculates under 43 CFR 3211.17. See §206.361 for

additional provisions applicable to determining gross proceeds under arm's-length sales.

(b) If you use the geothermal resource in your own power plant for the generation and sale of electricity, the following provisions apply

(1) For Class I leases, you must determine the royalty on produced geothermal resources in accordance with the first applicable of the following paragraphs:

(i) The gross proceeds accruing to you from the arm's-length sale of the electricity less applicable deductions determined under §206.353 and §206.354 of this part, multiplied by the royalty rate in your lease. See §206.361 for additional provisions applicable to determining gross proceeds under arm's-length sales. Under no circumstances may the deductions reduce the royalty value of the geothermal resource to zero; or

(ii) A royalty determined by any other reasonable method approved by MMS under §206.364 of this subpart.

(2) For Class II and Class III leases, the royalty on geothermal resources produced is your gross proceeds from the sale of electricity multiplied by the royalty rate BLM prescribed for your lease under 43 CFR 3211.17. See §206.361 for additional provisions applicable to determining gross proceeds under arm's-length sales. You may not reduce gross proceeds by any deductions.

### **§ 206.353 How do I determine transmission deductions?**



[top](#)

(a) If you determine the value of your geothermal resources under §206.352(b)(1)(i) of this subpart, you may subtract a transmission deduction from the gross proceeds you received for the sale of electricity to determine the plant tailgate value of the electricity.

(1) The transmission deduction consists of either or both of two components:

(i) Transmission line costs as determined under paragraph (b) of this section; and

(ii) Wheeling costs if the electricity is transmitted across a third party's transmission line under an arm's-length wheeling agreement.

(2) You may deduct the actual costs you (including your affiliate(s)) incur for transmitting electricity under your arm's-length wheeling contract.

(b) To determine your transmission line cost, you must follow the requirements of paragraphs (b)(1) and (b)(2) of this section.

(1) Your transmission line costs are your actual costs associated with the construction and operation of a transmission line for the purpose of transmitting electricity attributable and allocable to your power plant utilizing Federal geothermal resources.

(i) You must determine the monthly transmission line cost component of the transmission deduction by multiplying the annual transmission line cost rate (in dollars per kilowatt-hour) by the amount of electricity delivered for the reporting month.

(ii) You must redetermine the transmission line cost rate annually either at the beginning of the same month of the year in which the power plant was placed into service or at a time concurrent with the beginning of your annual corporate accounting period. The period you select must coincide with the same period you chose for the generating deduction under §206.354(b)(1). After you choose a deduction period, you may not later elect to use a different deduction period without MMS approval.

(2) Your actual transmission line costs during the reporting period include:

(i) Operating and maintenance expenses under paragraphs (d) and (e) of this section;

(ii) Overhead under paragraph (f) of this section; and either

(iii) Depreciation under paragraphs (g) and (h) of this section and a return on undepreciated capital

investment under paragraphs (g) and (i) of this section or

(iv) A return on the capital investment in the transmission line under paragraphs (g) and (j) of this section.

(c)(1) Allowable capital costs under paragraph (b) of this section are generally those for depreciable fixed assets (including costs of delivery and installation of capital equipment) that are an integral part of the transmission line.

(2)(i) You may include a return on capital you invested in the purchase of real estate for transmission facilities if:

(A) Such purchase is necessary; and

(B) The surface is not part of the Federal lease.

(ii) The rate of return will be the same rate determined under paragraph (k) of this section.

(d) Allowable operating expenses include:

(1) Operations supervision and engineering;

(2) Operations labor;

(3) Fuel;

(4) Utilities;

(5) Materials;

(6) Ad valorem property taxes;

(7) Rent;

(8) Supplies; and

(9) Any other directly allocable and attributable operating or maintenance expense that you can document.

(e) Allowable maintenance expenses include:

(1) Maintenance of the transmission line;

(2) Maintenance of equipment;

(3) Maintenance labor; and

(4) Other directly allocable and attributable maintenance expenses that you can document.

(f) Overhead directly attributable and allocable to the operation and maintenance of the transmission line is an allowable expense. State and Federal income taxes and severance taxes and other fees, including royalties, are not allowable expenses.

(g) To compute costs associated with capital investment, a lessee may use either depreciation with a return on undepreciated capital investment, or a return on capital investment in the transmission line. After a lessee has elected to use either method, the lessee may not later elect to change to the other alternative without MMS approval.

(h)(1) To compute depreciation, you must use a straight-line depreciation method based on the life of the geothermal project, usually the term of the electricity sales contract, or other depreciation period acceptable to MMS. You may not depreciate equipment below a reasonable salvage value.

(2) A change in ownership of a transmission line does not alter the depreciation schedule established by

the original lessee-owner for purposes of computing transmission line costs.

(3) With or without a change in ownership, you may depreciate a transmission line only once.

(i) To calculate a return on undepreciated capital investment, multiply the remaining undepreciated capital balance as of the beginning of the period for which you are calculating the transmission deduction by the rate of return provided in paragraph (k) of this section.

(j) To compute a return on capital investment in the transmission line, multiply the allowable capital investment in the transmission line by the rate of return determined pursuant to paragraph (k) of this section. There is no allowance for depreciation.

(k) The rate of return must be 2.0 multiplied by the industrial rate associated with Standard & Poor's BBB rating. The BBB rate must be the monthly average rate as published in Standard & Poor's Bond Guide for the first month for which the allowance is applicable. Redetermine the rate at the beginning of each subsequent calendar year.

(l) Calculate the deduction for transmission costs based on your cost of transmitting electricity through each individual transmission line.

(m)(1) For new transmission facilities or arrangements, base your initial deduction on estimates of allowable electricity transmission costs for the applicable period. Use the most recently available operations data for the transmission line or, if such data are not available, use estimates based on data for similar transmission lines.

(2) When actual cost information is available, you must amend your prior Form MMS-2014 reports to reflect actual transmission costs deductions for each month for which you reported and paid based on estimated transmission costs. You must pay any additional royalties due (together with interest computed under §218.302). You are entitled to a credit for or refund of any overpaid royalties.

(n) In conducting reviews and audits, MMS may require you to submit arm's-length transmission contracts, production agreements, operating agreements, and related documents and all other data used to calculate the deduction. You must comply with any such requirements within the time MMS specifies. Recordkeeping requirements are found at part 212 of this chapter.

(o) At the completion of transmission line dismantlement and salvage operations, you may report a credit for or request a refund of royalties in an amount equal to the royalty rate times the amount by which actual transmission line dismantlement costs exceed actual income attributable to salvage of the transmission line.

#### § 206.354 How do I determine generating deductions?



[top](#)

(a) If you determine the value of your geothermal resources under §206.352(b)(1)(i) of this subpart, you may deduct your reasonable actual costs incurred to generate electricity from the plant tailgate value of the electricity (usually the transmission-reduced value of the delivered electricity). You may deduct the actual costs you incur for generating electricity under your arm's-length power plant contract.

(b)(1) You must base your generating costs deduction on your actual annual costs associated with the construction and operation of a geothermal power plant.

(i) You must determine your monthly generating deduction by multiplying the annual generating cost rate (in dollars per kilowatt-hour) by the amount of plant tailgate electricity measured (or computed) for the reporting month. The generating cost rate is determined from the annual amount of your plant tailgate electricity.

(ii) You must redetermine your generating cost rate annually either at the beginning of the same month of the year in which the power plant was placed into service or at a time concurrent with the beginning of your annual corporate accounting period. The period you select must coincide with the same period chosen for the transmission deduction under §206.353(b)(1). After you choose a deduction period, you may not later elect to use a different deduction period without MMS approval.

(2) Your generating costs are your actual power plant costs during the reporting period, including:

- (i) Operating and maintenance expenses under paragraphs (d) and (e) of this section;
  - (ii) Overhead under paragraph (f) of this section; and either
  - (iii) Depreciation under paragraphs (g) and (h) of this section and a return on undepreciated capital investment under paragraphs (g) and (i) of this section; or
  - (iv) A return on capital investment in the power plant under paragraphs (g) and (j) of this section.
- (c)(1) Allowable capital costs under paragraph (b) of this section are generally those for depreciable fixed assets (including costs of delivery and installation of capital equipment) that are an integral part of the power plant or are required by the design specifications of the power conversion cycle.
- (2)(i) You may include a return on capital you invested in the purchase of real estate for a power plant site if:
- (A) The purchase is necessary; and,
  - (B) The surface is not part of the Federal lease.
- (ii) The rate of return will be the same rate determined under paragraph (k) of this section.
- (3) You may not deduct the costs of gathering systems and other production-related facilities.
- (d) Allowable operating expenses include:
- (1) Operations supervision and engineering;
  - (2) Operations labor;
  - (3) Auxiliary fuel and/or utilities used to operate the power plant during down time;
  - (4) Utilities;
  - (5) Materials;
  - (6) Ad valorem property taxes;
  - (7) Rent;
  - (8) Supplies; and
  - (9) Any other directly allocable and attributable operating expense.
- (e) Allowable maintenance expenses include:
- (1) Maintenance of the power plant;
  - (2) Maintenance of equipment;
  - (3) Maintenance labor; and
  - (4) Other directly allocable and attributable maintenance expenses that you can document.
- (f) Overhead directly attributable and allocable to the operation and maintenance of the power plant is an allowable expense. State and Federal income taxes and severance taxes and other fees, including royalties, are not allowable expenses.
- (g) To compute costs associated with capital investment, a lessee may use either depreciation with a return on undepreciated capital investment, or a return on capital investment in the power plant. After a lessee has elected to use either method, the lessee may not later elect to change to the other alternative without MMS approval.

(h)(1) To compute depreciation, you must use a straight-line depreciation method based on the life of the geothermal project, usually the term of the electricity sales contract, or other depreciation period acceptable to MMS. You may not depreciate equipment below a reasonable salvage value.

(2) A change in ownership of the power plant does not alter the depreciation schedule established by the original lessee-owner for purposes of computing generating costs.

(3) With or without a change in ownership, you may depreciate a power plant only once.

(i) To calculate a return on undepreciated capital investment, multiply the remaining undepreciated capital balance as of the beginning of the period for which you are calculating the generating deduction allowance by the rate of return provided in paragraph (k) of this section.

(j) To compute a return on capital investment in the power plant, multiply the allowable capital investment in the power plant by the rate of return determined pursuant to paragraph (k) of this section. There is no allowance for depreciation.

(k) The rate of return must be 2.0 multiplied by the industrial rate associated with Standard & Poor's BBB rating. The BBB rate must be the monthly average rate as published in Standard & Poor's Bond Guide for the first month for which the allowance is applicable. You must redetermine the rate at the beginning of each subsequent calendar year.

(l) Calculate the deduction for generating costs based on your cost of generating electricity through each individual power plant.

(m)(1) For new power plants or arrangements, base your initial deduction on estimates of allowable electricity generation costs for the applicable period. Use the most recently available operations data for the power plant or, if such data are not available, use estimates based on data for similar power plants.

(2) When actual cost information is available, you must amend your prior Form MMS-2014 reports to reflect actual generating cost deductions for each month for which you reported and paid based on estimated generating costs. You must pay any additional royalties due (together with interest computed under §218.302). You are entitled to a credit for or refund of any overpaid royalties.

(n) In conducting reviews and audits, MMS may require you to submit arm's-length power plant contracts, production agreements, operating agreements, related documents and all other data used to calculate the deduction. You must comply with any such requirements within the time MMS specifies. Recordkeeping requirements are found at part 212 of this chapter.

(o) At the completion of power plant dismantlement and salvage operations, you may report a credit for or request a refund of royalty in an amount equal to the royalty rate times the amount by which actual power plant dismantlement costs exceed actual income attributable to salvage of the power plant.

#### **§ 206.355 How do I calculate royalty due on geothermal resources I sell at arm's length to a purchaser for direct use?**



[top](#)

If you sell geothermal resources produced from Class I, II, or III leases at arm's length to a purchaser for direct use, then the royalty on the geothermal resource is the gross proceeds accruing to you from the sale of the geothermal resource to the arm's-length purchaser multiplied by the royalty rate in your lease or that BLM prescribes under 43 CFR 3211.18. See §206.361 for additional provisions applicable to determining gross proceeds under arm's-length sales.

#### **§ 206.356 How do I calculate royalty or fees due on geothermal resources I use for direct use purposes?**



[top](#)

If you use the geothermal resource for direct use:

(a) For Class I leases, you must determine the royalty due on geothermal resources in accordance with the first applicable of the following three paragraphs.

(1) The weighted average of the gross proceeds established in arm's-length contracts for the purchase of significant quantities of geothermal resources to operate the lessee's same direct-use facility multiplied by the royalty rate in your lease. In evaluating the acceptability of arm's-length contracts, the following factors will be considered: time of execution, duration, terms, volume, quality of resource, and such other factors as may be appropriate to reflect the value of the resource.

(2) The equivalent value of the least expensive, reasonable alternative energy source (fuel) multiplied by the royalty rate in your lease. The equivalent value of the least expensive, reasonable alternative energy source will be based on the amount of thermal energy that would otherwise be used by the direct use facility in place of the geothermal resource. That amount of thermal energy (in Btu) displaced by the geothermal resource will be determined by the equation:

$$\text{thermal energy displaced} = \frac{(h_{in} - h_{out}) \times \text{density} \times 0.113681 \times \text{volume}}{\text{efficiency factor}}$$

Where  $h_{in}$  is the enthalpy in Btu/lb at the direct use facility inlet (based on measured inlet temperature),  $h_{out}$  is the enthalpy in Btu/lb at the facility outlet (based on measured outlet temperature), density is in lbs/cu ft based on inlet temperature, the factor 0.113681 (cu ft/gal) converts gallons to cubic feet, and volume is the quantity of geothermal fluid in gallons produced at the wellhead or measured at an approved point. The efficiency factor of the alternative energy source will be 0.7 for coal and 0.8 for oil, natural gas, and other fuels derived from oil and natural gas, or an efficiency factor proposed by the lessee and approved by MMS. The methods of measuring resource parameters (temperature, volume, etc.) and the frequency of computing and accumulating the amount of thermal energy displaced will be determined and approved by BLM under 43 CFR 3275.13–3275.17.

(3) A royalty determined by any other reasonable method approved by MMS or the Assistant Secretary, Land and Minerals Management of the Department of the Interior, under §206.364 of this part.

(b) For geothermal resources produced from Class II and Class III leases, you must multiply the appropriate fee from the schedule in subparagraph (b)(1) of this section by the number of gallons or pounds you produce from the direct use lease each month.

(1) You must use the following fee schedule to calculate fees due under this section:

#### Direct Use Fee Schedule

[Hot water]

If your average monthly inlet temperature ( °F) is		Your fees are . . .	
At least . . .	But less than . . .	(\$/million gallons)	(\$/million pounds)
130	140	2.524	0.307
140	150	7.549	0.921
150	160	12.543	1.536
160	170	17.503	2.150
170	180	22.426	2.764
180	190	27.310	3.379
190	200	32.153	3.993
200	210	36.955	4.607
210	220	41.710	5.221
220	230	46.417	5.836
230	240	51.075	6.450
240	250	55.682	7.064
250	260	60.236	7.679
260	270	64.736	8.293

270	280	69.176	8.907
280	290	73.558	9.521
290	300	77.876	10.136
300	310	82.133	10.750
310	320	86.328	11.364
320	330	90.445	11.979
330	340	94.501	12.593
340	350	98.481	13.207
350	360	102.387	13.821

(i) For direct use geothermal resources with an average monthly inlet temperature of 130 °F or less, you must pay only the lease rental.

(ii) The MMS, in consultation with BLM, will develop and publish a revised fee schedule in the Federal Register, as needed.

(iii) The MMS, in consultation with BLM, will calculate revised fees schedules using the following formulas:

For reporting on a volume basis:  $R_v = \rho \times (T_{in} - T_{out}) \times P_{prbc} \times F_{rr} \times \frac{1}{e}$

For reporting on a mass basis:  $R_m = (T_{in} - T_{out}) \times P_{prbc} \times F_{rr} \times \frac{1}{e}$

Where:

$R_v$  = Royalty due as a function of produced volume in the fee schedule, expressed as dollars per million ( $10^6$ ) gallons;

$R_m$  = Royalty due as a function of produced mass in the fee schedule, expressed as dollars per million ( $10^6$ ) pounds;

$\rho$ [rho] = Water density at inlet temperature expressed as lbs per gallon;

$T_{in}$  = Measured inlet temperature in °F (as required by BLM under 43 CFR part 3275);

$T_{out}$  = Established assumed outlet temperature of 130°F;

$e$  = Boiler Efficiency Factor for coal of 70 percent;

$P_{prbc}$  = The 3-year historical average of Powder River Basin spot coal prices, as published by the Energy Information Administration, or other recognized authoritative reference source of coal prices, in dollars (per MMBtu);

$F_{rr}$  = The assumed Lease Royalty Rate of 10 percent.

(2) The fee that you report is subject to monitoring, review, and audit.

(3) The schedule of fees established under this paragraph will apply to any Class III lease with respect to any royalty payments previously made when the lease was a Class I lease that were due and owing, and were paid, on or after July 16, 2003. To use this provision, you must provide MMS data showing the amount of geothermal production in pounds or gallons of geothermal fluid to input into the fee schedule (see 43 CFR part 3276).

(i) If the royalties you previously paid are less than the fees due under this section, you must pay the difference plus interest on that difference computed under §218.302.

(ii) If the royalties you previously paid are more than the fees due under this section, then you are entitled to a refund or credit from MMS of 50 percent of the overpaid royalties. You are also entitled to a refund or credit of any interest that you paid on the overpaid royalties.

(c) For geothermal resources other than hot water, MMS will determine fees on a case-by-case basis.

#### **§ 206.357 How do I calculate royalty due on byproducts?**



(a) If you sell byproducts, you must determine the royalty due on the byproducts that are royalty-bearing under:

(1) Applicable lease terms of Class I leases and of Class III leases that do not elect to be subject to all of the BLM regulations promulgated for leases issued after August 8, 2005, under 43 CFR 3200.7(a)(2), or

(2) Applicable statutory provisions at 30 U.S.C. 1004(a)(2) for Class II leases and for Class III leases that do elect to be subject to all of the BLM regulations promulgated for leases issued after August 8, 2005, under 43 CFR 3200.7(a)(2).

(b) You must determine the royalty due on the byproducts by multiplying the royalty rate in your lease or that BLM prescribes under 43 CFR 3211.19 by a value of the byproducts determined in accordance with the first applicable of the following subparagraphs:

(1) The gross proceeds accruing to you from the arm's-length sale of the byproducts, less any applicable byproduct transportation allowances determined under §§206.358 and 206.359. See §206.361 for additional provisions applicable to determining gross proceeds;

(2) Other relevant matters including, but not limited to, published or publicly available spot-market prices, or information submitted by the lessee concerning circumstances unique to a particular lease operation or the saleability of certain byproducts; or

(3) Any other reasonable valuation method approved by MMS.

#### **§ 206.358 What are byproduct transportation allowances?**



(a) When you determine the value of byproducts at a point off the geothermal lease, unit, or participating area, you are allowed a deduction in determining value, for royalty purposes, for your reasonable, actual costs incurred to:

(1) Transport the byproducts from a Federal lease, unit, or participating area to a sales point or point of delivery that is off the lease, unit, or participating area; or

(2) Transport the byproducts from a Federal lease, unit, or participating area, or from a geothermal use facility to a byproduct recovery facility when that byproduct recovery facility is off the lease, unit, or participating area and, if applicable, from the recovery facility to a sales point or point of delivery off the lease, unit, or participating area.

(b) Costs for transporting geothermal fluids from the lease to the geothermal use facility, whether on or off the lease, are not includible in the byproduct transportation allowance.

(c)(1) When you transport byproducts from a lease, unit, participating area, or geothermal use facility to a byproduct recovery facility, you are not required to allocate transportation costs between the quantity of marketable byproducts and the rejected waste material. The byproduct transportation allowance is authorized for the total production that is transported. You must express byproduct transportation allowances as a cost per unit of marketable byproducts transported.

(2) For byproducts that are extracted on the lease, unit, participating area, or at the geothermal use facility, the byproduct transportation allowance is authorized for the total byproduct that is transported to a point of sale off the lease, unit, or participating area. You must express byproduct transportation allowances as a cost per unit of byproduct transported.

(3) You may deduct transportation costs only when you sell, deliver, or otherwise utilize the transported byproduct and report and pay royalties on the byproduct.

(d) *Reporting requirements.* (1) You must use a discrete field on Form MMS-2014 to notify MMS of a transportation allowance.

(2) In conducting reviews and audits, MMS may require you to submit arm's-length transportation contracts, production agreements, operating agreements, and related documents. You must comply with any such requirements within the time MMS specifies. Recordkeeping requirements are found at part 212 of this chapter.

(e) Byproduct transportation allowances are subject to monitoring, review, and audit. If, after a review or audit, MMS determines that you have improperly determined a byproduct transportation allowance, you must pay any additional royalties due (plus interest computed under §218.302). You are entitled to a credit for or refund of any overpaid royalties.

(f) If you commingled byproducts produced from Federal and non-Federal leases for transportation, you may not disproportionately allocate transportation costs to Federal lease production.

### § 206.359 How do I determine byproduct transportation allowances?



(a) For transportation costs you incur under an arm's-length contract, the transportation allowance will be the reasonable, actual costs you incurred for transporting the byproducts under that contract.

(1) In conducting reviews and audits, MMS will examine whether the contract reflects more than the consideration actually transferred either directly or indirectly from you to the transporter for the transportation. If the contract reflects more than the total consideration you paid, MMS may require you to determine the byproduct transportation allowance under paragraph (b) of this section.

(2) If MMS determines that the consideration you paid under an arm's-length byproduct transportation contract does not reflect the reasonable value of the transportation because of misconduct by or between the contracting parties, or because you otherwise have breached your duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, MMS will require you to determine the byproduct transportation allowance under paragraph (b) of this section. When MMS determines that the value of the transportation may be unreasonable, MMS will notify you and give you an opportunity to provide written information justifying your transportation costs.

(3) Where your payments for transportation under an arm's-length contract are not established on a dollars-per-unit basis, you must convert whatever consideration you paid to a dollar value equivalent for the purposes of this section.

(b) If you transport the byproduct yourself or under a non-arm's-length transportation arrangement, the byproduct transportation allowance is your reasonable actual costs for transportation during the reporting period, including:

(1) Operating and maintenance expenses under paragraphs (d) and (e) of this section;

(2) Overhead under paragraph (f) of this section; and either

(3) Depreciation under paragraphs (g) and (h) of this section and a return on undepreciated capital investment under paragraphs (g) and (i) of this section; or

(4) A return on capital investment in the transportation system under paragraphs (g) and (j) of this section.

(c)(1) Allowable capital costs under paragraph (b) of this section are generally those for depreciable fixed assets (including costs of delivery and installation of capital equipment) that are an integral part of the transportation system.

(2)(i) You may include a return on capital you invested in the purchase of real estate to locate the byproduct transportation facilities if:

(A) The purchase is necessary; and

(B) The surface is not part of a Federal lease.

(ii) The rate of return will be the same rate determined in paragraph (k) of this section.

(3) You may not deduct the costs of gathering systems and other production-related facilities.

(d) Allowable operating expenses include:

(1) Operations supervision and engineering;

(2) Operations labor;

(3) Fuel;

(4) Utilities;

(5) Materials;

(6) Ad valorem property taxes;

(7) Rent;

(8) Supplies; and

(9) Any other directly allocable and attributable operating expense that you can document.

(e) Allowable maintenance expenses include:

(1) Maintenance of the transportation system;

(2) Maintenance of equipment;

(3) Maintenance labor; and

(4) Other directly allocable and attributable maintenance expenses that you can document.

(f) Overhead directly attributable and allocable to the operation and maintenance of the transportation system is an allowable expense. State and Federal income taxes and severance taxes and other fees, including royalties, are not allowable expenses.

(g) To compute costs associated with capital investment, a lessee may use either paragraphs (h) and (i) or paragraph (j) of this section. After a lessee has elected to use either method for a transportation system, the lessee may not later elect to change to the other alternative without MMS approval.

(h)(1) To compute depreciation, you must use a straight-line depreciation method based on either the life of the equipment or the life of the geothermal project which the transportation system services. After you choose the basis for depreciation, you may not change that basis without MMS approval. You may not depreciate equipment below a reasonable salvage value.

(2) A change in ownership of a transportation system does not alter the depreciation schedule established by the original lessee-owner for purposes of computing transportation costs.

(3) With or without a change in ownership, you may depreciate a transportation system only once.

(i) To calculate a return on undepreciated capital investment, multiply the remaining undepreciated capital balance as of the beginning of the period for which you are calculating the transportation allowance by the rate of return provided in paragraph (k) of this section.

(j) To compute a return on capital investment in the transportation system, the allowed cost will be the amount equal to the allowable capital investment in the transportation system multiplied by the rate of return determined pursuant to paragraph (k) of this section. There is no allowance for depreciation.

(k) The rate of return must be the industrial rate associated with Standard & Poor's BBB rating. The BBB

rate must be the monthly average rate as published in Standard & Poor's Bond Guide for the first month for which the allowance is applicable. You must redetermine the rate at the beginning of each subsequent calendar year.

(l)(1) For new transportation facilities or arrangements, base your initial deduction on estimates of allowable byproduct transportation costs for the applicable period. Use the most recently available operations data for the transportation system or, if such data are not available, use estimates based on data for similar transportation systems.

(2) When actual cost information is available, you must amend your prior Form MMS-2014 reports to reflect actual byproduct transportation cost deductions for each month for which you reported and paid based on estimated byproduct transportation costs. You must pay any additional royalties due (together with interest computed under §218.302). You are entitled to a credit for or a refund of any overpaid royalties.

**§ 206.360 What records must I keep to support my calculations of royalty or fees under this subpart?**



[top](#)

If you determine royalties or direct use fees for your geothermal resource under this subpart, you must retain all data relevant to the determination of the royalty value or the fee you paid. Recordkeeping requirements are found at part 212 of this chapter.

(a) You must be able to show:

(1) How you calculated the royalty value or fee you reported, including all allowable deductions; and

(2) How you complied with this subpart.

(b) Upon request, you must submit all data to MMS. You must comply with any such requirement within the time MMS specifies.

**§ 206.361 How will MMS determine whether my royalty or direct use fee payments are correct?**



[top](#)

(a)(1) The royalties or direct use fees that you report are subject to monitoring, review, and audit. The MMS may review and audit your data, and MMS will direct you to use a different measure of royalty value, gross proceeds, or fee, whichever is applicable, if it determines that the reported value, gross proceeds, or fee is inconsistent with the requirements of this subpart.

(2) If MMS directs you to use a different royalty value, measure of gross proceeds, or fee, you must either pay any royalties or fees due (together with interest computed under §218.302) or report a credit for or request a refund of any overpaid royalties or fees.

(b) When the provisions in this subpart refer to gross proceeds either for the sale of electricity or the sale of a geothermal resource, in conducting reviews and audits MMS will examine whether your sales contract reflects the total consideration actually transferred, either directly or indirectly, from the buyer to you for the geothermal resource or electricity. If MMS determines that a contract does not reflect the total consideration, or the gross proceeds accruing to you under a contract do not reflect reasonable consideration because of misconduct by or between the contracting parties, or because you otherwise have breached your duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, MMS may require you to increase the gross proceeds to reflect any additional consideration. Alternatively, for Class I leases, MMS may require you to use another valuation method in the regulations applicable to dispositions other than under an arm's-length contract. The MMS will notify you to give you an opportunity to provide written information justifying your gross proceeds.

(c) For arm's-length sales, you have the burden of demonstrating that your contract is arm's length.

(d) The MMS may require you to certify that the provisions in your sales contract include all of the consideration the buyer paid you, either directly or indirectly, for the electricity or geothermal resource.

(e) Notwithstanding any other provision of this subpart, under no circumstances will the value of production for royalty purposes under a Class I lease where the geothermal resources are sold before use be less than the gross proceeds accruing to you.

(f) Gross proceeds for the sale of electricity or for the sale of the geothermal resource will be based on the highest price a prudent lessee can receive through legally enforceable claims under its contract.

(1) Absent contract revision or amendment, if you fail to take proper or timely action to receive prices or benefits to which you are entitled, you must pay royalty based upon that obtainable price or benefit.

(2) Contract revisions or amendments you make must be in writing and signed by all parties to the contract.

(3) If you make timely application for a price increase or benefit allowed under your contract, but the purchaser refuses and you take reasonable measures, which are documented, to force purchaser compliance, you will owe no additional royalties unless or until you receive additional monies or consideration resulting from the price increase. This paragraph (f)(3) will not be construed to permit you to avoid your royalty payment obligation in situations where a purchaser fails to pay, in whole or in part or timely, for a quantity of geothermal resources or electricity.

#### **§ 206.362 What are my responsibilities to place production into marketable condition and to market production?**



[top](#)

You must place geothermal resources and byproducts in marketable condition and market the geothermal resources or byproducts for the mutual benefit of the lessee and the lessor at no cost to the Federal Government. If you use gross proceeds under an arm's-length contract in determining royalty, you must increase those gross proceeds to the extent that the purchaser, or any other person, provides certain services that the seller normally would be responsible to perform to place the geothermal resources or byproducts in marketable condition or to market the geothermal resources or byproducts.

#### **§ 206.363 When is an MMS audit, review, reconciliation, monitoring, or other like process considered final?**



[top](#)

Notwithstanding any provision in these regulations to the contrary, no audit, review, reconciliation, monitoring, or other like process that results in a redetermination by MMS of royalty or fees due under this subpart is considered final or binding as against the Federal Government or its beneficiaries until MMS formally closes the audit period in writing.

#### **§ 206.364 How do I request a value or gross proceeds determination?**



[top](#)

(a) You may request a value determination from MMS regarding any geothermal resources produced from a Class I lease or for byproducts produced from a Class I, Class II, or Class III lease. You may also request a gross proceeds determination for a Class II or Class III lease. Your request must:

(1) Be in writing;

(2) Identify specifically all leases involved, all owners of interests in those leases, and the operator(s) for those leases;

(3) Completely explain all relevant facts. You must inform MMS of any changes to relevant facts that occur before we respond to your request;

(4) Include copies of all relevant documents;

(5) Provide your analysis of the issue(s), including citations to all relevant precedents (including adverse precedents); and

(6) Suggest your proposed gross proceeds calculation or valuation method.

(b) In response to your request:

(1) The Assistant Secretary, Land and Minerals Management, may issue a determination; or

(2) The MMS may issue a determination; or

(3) The MMS may inform you in writing that MMS will not provide a determination. Situations in which MMS typically will not provide any determination include, but are not limited to:

(i) Requests for guidance on hypothetical situations; and

(ii) Matters that are the subject of pending litigation or administrative appeals.

(c)(1) A determination signed by the Assistant Secretary, Land and Minerals Management, is binding on both you and MMS until the Assistant Secretary modifies or rescinds it.

(2) After the Assistant Secretary issues a determination, you must make any adjustments in royalty payments that follow from the determination and, if you owe additional royalties, pay the royalties owed together with late payment interest computed under §218.302.

(3) A determination signed by the Assistant Secretary is the final action of the Department and is subject to judicial review under 5 U.S.C. 701–706.

(d) A determination issued by MMS is binding on MMS and delegated States, but not on you, with respect to the specific situation addressed in the determination unless the MMS (for MMS-issued determinations) or the Assistant Secretary modifies or rescinds it.

(1) A determination by MMS is not an appealable decision or order under 30 CFR part 290 subpart B.

(2) If you receive an order requiring you to pay royalty on the same basis as the determination, you may appeal that order under 30 CFR part 290 subpart B.

(e) In making a determination, MMS or the Assistant Secretary may use any of the applicable criteria in this subpart.

(f) A change in an applicable statute or regulation on which any determination is based takes precedence over the determination after the effective date of the statute or regulation, regardless of whether the MMS or the Assistant Secretary modifies or rescinds the determination.

(g) The MMS or the Assistant Secretary generally will not retroactively modify or rescind a determination issued under paragraph (d) of this section, unless:

(1) There was a misstatement or omission of material facts; or

(2) The facts subsequently developed are materially different from the facts on which the guidance was based.

(h) The MMS may make requests and replies under this section available to the public, subject to the confidentiality requirements under §206.365.

#### **§ 206.365 Does MMS protect information I provide?**



[top](#)

Certain information you submit to MMS regarding royalties or fees on geothermal resources or byproducts, including deductions and allowances, may be exempt from disclosure. To the extent applicable laws and regulations permit, MMS will keep confidential any data you submit that is privileged, confidential, or otherwise exempt from disclosure. All requests for information must be submitted under the Freedom of Information Act regulations of the Department of the Interior at 43 CFR part 2.

**§ 206.366 What is the nominal fee that a State, tribal, or local government lessee must pay for the use of geothermal resources?**



[top](#)

If a State, tribal, or local government lessee uses a geothermal resource without sale and for public purposes—other than commercial production or generation of electricity—the State, tribal, or local government lessee must pay a nominal fee. A nominal fee means a slight or *de minimis* fee. The MMS will determine the fee on a case-by-case basis.

**Subpart I—OCS Sulfur [Reserved]**



[top](#)

**Subpart J—Indian Coal**



[top](#)

**Source:** 61 FR 5481, Feb. 12, 1996, unless otherwise noted.

**§ 206.450 Purpose and scope.**



[top](#)

(a) This subpart prescribes the procedures to establish the value, for royalty purposes, of all coal from Indian Tribal and allotted leases (except leases on the Osage Indian Reservation, Osage County, Oklahoma).

(b) If the specific provisions of any statute, treaty, or settlement agreement between the Indian lessor and a lessee resulting from administrative or judicial litigation, or any coal lease subject to the requirements of this subpart, are inconsistent with any regulation in this subpart, then the statute, treaty, lease provision, or settlement shall govern to the extent of that inconsistency.

(c) All royalty payments are subject to later audit and adjustment.

(d) The regulations in this subpart are intended to ensure that the trust responsibilities of the United States with respect to the administration of Indian coal leases are discharged in accordance with the requirements of the governing mineral leasing laws, treaties, and lease terms.

**§ 206.451 Definitions.**



[top](#)

*Ad valorem lease* means a lease where the royalty due to the lessor is based upon a percentage of the amount or value of the coal.

*Allowance* means an approved, or an MMS-initially accepted deduction in determining value for royalty purposes. Coal washing allowance means an allowance for the reasonable, actual costs incurred by the lessee for coal washing, or an approved or MMS-initially accepted deduction for the costs of washing coal, determined pursuant to this subpart. Transportation allowance means an allowance for the reasonable, actual costs incurred by the lessee for moving coal to a point of sale or point of delivery remote from both the lease and mine or wash plant, or an approved MMS-initially accepted deduction for costs of such transportation, determined pursuant to this subpart.

*Area* means a geographic region in which coal has similar quality and economic characteristics. Area boundaries are not officially designated and the areas are not necessarily named.

*Arm's-length contract* means a contract or agreement that has been arrived at in the marketplace between independent, nonaffiliated persons with opposing economic interests regarding that contract. For purposes of this subpart, two persons are affiliated if one person controls, is controlled by, or is under common control with another person. For purposes of this subpart, based on the instruments of

ownership of the voting securities of an entity, or based on other forms of ownership: ownership in excess of 50 percent constitutes control; ownership of 10 through 50 percent creates a presumption of control; and ownership of less than 10 percent creates a presumption of noncontrol which MMS may rebut if it demonstrates actual or legal control, including the existence of interlocking directorates. Notwithstanding any other provisions of this subpart, contracts between relatives, either by blood or by marriage, are not arm's-length contracts. MMS may require the lessee to certify ownership control. To be considered arm's-length for any production month, a contract must meet the requirements of this definition for that production month, as well as when the contract was executed.

*Audit* means a review, conducted in accordance with generally accepted accounting and auditing standards, of royalty payment compliance activities of lessees or other interest holders who pay royalties, rents, or bonuses on Indian leases.

*BIA* means the Bureau of Indian Affairs of the Department of the Interior.

*BLM* means the Bureau of Land Management of the Department of the Interior.

*Coal* means coal of all ranks from lignite through anthracite.

*Coal washing* means any treatment to remove impurities from coal. Coal washing may include, but is not limited to, operations such as flotation, air, water, or heavy media separation; drying; and related handling (or combination thereof).

*Contract* means any oral or written agreement, including amendments or revisions thereto, between two or more persons and enforceable by law that with due consideration creates an obligation.

*Gross proceeds* (for royalty payment purposes) means the total monies and other consideration accruing to a coal lessee for the production and disposition of the coal produced. Gross proceeds includes, but is not limited to, payments to the lessee for certain services such as crushing, sizing, screening, storing, mixing, loading, treatment with substances including chemicals or oils, and other preparation of the coal to the extent that the lessee is obligated to perform them at no cost to the Indian lessor. Gross proceeds, as applied to coal, also includes but is not limited to reimbursements for royalties, taxes or fees, and other reimbursements. Tax reimbursements are part of the gross proceeds accruing to a lessee even though the Indian royalty interest may be exempt from taxation. Monies and other consideration, including the forms of consideration identified in this paragraph, to which a lessee is contractually or legally entitled but which it does not seek to collect through reasonable efforts are also part of gross proceeds.

*Indian allottee* means any Indian for whom land or an interest in land is held in trust by the United States or who holds title subject to Federal restriction against alienation.

*Indian Tribe* means any Indian Tribe, band, nation, pueblo, community, rancheria, colony, or other group of Indians for which any land or interest in land is held in trust by the United States or which is subject to Federal restriction against alienation.

*Lease* means any contract, profit-share arrangement, joint venture, or other agreement issued or approved by the United States for an Indian coal resource under a mineral leasing law that authorizes exploration for, development or extraction of, or removal of coal—or the land covered by that authorization, whichever is required by the context.

*Lessee* means any person to whom the Indian Tribe or an Indian allottee issues a lease, and any person who has been assigned an obligation to make royalty or other payments required by the lease. This includes any person who has an interest in a lease as well as an operator or payor who has no interest in the lease but who has assumed the royalty payment responsibility.

*Like-quality coal* means coal that has similar chemical and physical characteristics.

*Marketable condition* means coal that is sufficiently free from impurities and otherwise in a condition that it will be accepted by a purchaser under a sales contract typical for that area.

*Mine* means an underground or surface excavation or series of excavations and the surface or underground support facilities that contribute directly or indirectly to mining, production, preparation, and handling of lease products.

*MMS* means the Minerals Management Service of the Department of the Interior.

*Net-back method* means a method for calculating market value of coal at the lease or mine. Under this

method, costs of transportation, washing, handling, etc., are deducted from the ultimate proceeds received for the coal at the first point at which reasonable values for the coal may be determined by a sale pursuant to an arm's-length contract or by comparison to other sales of coal, to ascertain value at the mine.

*Net output* means the quantity of washed coal that a washing plant produces.

*Person* means by individual, firm, corporation, association, partnership, consortium, or joint venture.

*Sales type code* means the contract type or general disposition (e.g., arm's-length or non-arm's-length) of production from the lease. The sales type code applies to the sales contract, or other disposition, and not to the arm's-length or non-arm's-length nature of a transportation or washing allowance.

*Spot market price* means the price received under any sales transaction when planned or actual deliveries span a short period of time, usually not exceeding one year.

[61 FR 5481, Feb. 12, 1996, as amended at 64 FR 43289, Aug. 10, 1999; 73 FR 15891, Mar. 26, 2008]

## § 206.452 Coal subject to royalties—general provisions.



[top](#)

(a) All coal (except coal unavoidably lost as determined by BLM pursuant to 43 CFR group 3400) from an Indian lease subject to this part is subject to royalty. This includes coal used, sold, or otherwise disposed of by the lessee on or off the lease.

(b) If a lessee receives compensation for unavoidably lost coal through insurance coverage or other arrangements, royalties at the rate specified in the lease are to be paid on the amount of compensation received for the coal. No royalty is due on insurance compensation received by the lessee for other losses.

(c) If waste piles or slurry ponds are reworked to recover coal, the lessee shall pay royalty at the rate specified in the lease at the time the recovered coal is used, sold, or otherwise finally disposed of. The royalty rate shall be that rate applicable to the production method used to initially mine coal in the waste pile or slurry pond; i.e., underground mining method or surface mining method. Coal in waste pits or slurry ponds initially mined from Indian leases shall be allocated to such leases regardless of whether it is stored on Indian lands. The lessee shall maintain accurate records to determine to which individual Indian lease coal in the waste pit or slurry pond should be allocated. However, nothing in this section requires payment of a royalty on coal for which a royalty has already been paid.

## § 206.453 Quality and quantity measurement standards for reporting and paying royalties.



[top](#)

For all leases subject to this subpart, the quantity of coal on which royalty is due shall be measured in short tons (of 2,000 pounds each) by methods prescribed by the BLM. Coal quantity information will be reported on appropriate forms required under 30 CFR part 210—Forms and Reports.

[61 FR 5481, Feb. 12, 1996, as amended at 66 FR 45769, Aug. 30, 2001; 73 FR 15892, Mar. 26, 2008]

## § 206.454 Point of royalty determination.



[top](#)

(a) For all leases subject to this subpart, royalty shall be computed on the basis of the quantity and quality of Indian coal in marketable condition measured at the point of royalty measurement as determined jointly by BLM and MMS.

(b) Coal produced and added to stockpiles or inventory does not require payment of royalty until such coal is later used, sold, or otherwise finally disposed of. MMS may ask BLM or BIA to increase the lease bond to protect the lessor's interest when BLM determines that stockpiles or inventory become excessive so as to increase the risk of degradation of the resource.

(c) The lessee shall pay royalty at a rate specified in the lease at the time the coal is used, sold, or otherwise finally disposed of, unless otherwise provided for at §206.455(d) of this subpart.

#### **§ 206.455 Valuation standards for cents-per-ton leases.**



(a) This section is applicable to coal leases on Indian Tribal and allotted Indian lands (except leases on the Osage Indian Reservation, Osage County, Oklahoma) which provide for the determination of royalty on a cents-per-ton (or other quantity) basis.

(b) The royalty for coal from leases subject to this section shall be based on the dollar rate per ton prescribed in the lease. That dollar rate shall be applicable to the actual quantity of coal used, sold, or otherwise finally disposed of, including coal which is avoidably lost as determined by BLM pursuant to 43 CFR part 3400.

(c) For leases subject to this section, there shall be no allowances for transportation, removal of impurities, coal washing, or any other processing or preparation of the coal.

(d) When a coal lease is readjusted pursuant to 43 CFR part 3400 and the royalty valuation method changes from a cents-per-ton basis to an ad valorem basis, coal which is produced prior to the effective date of readjustment and sold or used within 30 days of the effective date of readjustment shall be valued pursuant to this section. All coal that is not used, sold, or otherwise finally disposed of within 30 days after the effective date of readjustment shall be valued pursuant to the provisions of §206.456 of this subpart, and royalties shall be paid at the royalty rate specified in the readjusted lease.

#### **§ 206.456 Valuation standards for ad valorem leases.**



(a) This section is applicable to coal leases on Indian Tribal and allotted Indian lands (except leases on the Osage Indian Reservation, Osage County, Oklahoma) which provide for the determination of royalty as a percentage of the amount of value of coal (ad valorem). The value for royalty purposes of coal from such leases shall be the value of coal determined pursuant to this section, less applicable coal washing allowances and transportation allowances determined pursuant to §§206.457 through 206.461 of this subpart, or any allowance authorized by §206.464 of this subpart. The royalty due shall be equal to the value for royalty purposes multiplied by the royalty rate in the lease.

(b)(1) The value of coal that is sold pursuant to an arm's-length contract shall be the gross proceeds accruing to the lessee, except as provided in paragraphs (b)(2), (b)(3), and (b)(5) of this section. The lessee shall have the burden of demonstrating that its contract is arm's-length. The value which the lessee reports, for royalty purposes, is subject to monitoring, review, and audit.

(2) In conducting reviews and audits, MMS will examine whether the contract reflects the total consideration actually transferred either directly or indirectly from the buyer to the seller for the coal produced. If the contract does not reflect the total consideration, then MMS may require that the coal sold pursuant to that contract be valued in accordance with paragraph (c) of this section. Value may not be based on less than the gross proceeds accruing to the lessee for the coal production, including the additional consideration.

(3) If MMS determines that the gross proceeds accruing to the lessee pursuant to an arm's-length contract do not reflect the reasonable value of the production because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then MMS shall require that the coal production be valued pursuant to paragraphs (c)(2)(ii), (c)(2)(iii), (c)(2)(iv), or (c)(2)(v) of this section, and in accordance with the notification requirements of paragraph (d)(3) of this section. When MMS determines that the value may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's reported coal value.

(4) MMS may require a lessee to certify that its arm's-length contract provisions include all of the consideration to be paid by the buyer, either directly or indirectly, for the coal production.

(5) The value of production for royalty purposes shall not include payments received by the lessee pursuant to a contract which the lessee demonstrates, to MMS' satisfaction, were not part of the total consideration paid for the purchase of coal production.

(c)(1) The value of coal from leases subject to this section and which is not sold pursuant to an arm's-length contract shall be determined in accordance with this section.

(2) If the value of the coal cannot be determined pursuant to paragraph (b) of this section, then the value shall be determined through application of other valuation criteria. The criteria shall be considered in the following order, and the value shall be based upon the first applicable criterion:

(i) The gross proceeds accruing to the lessee pursuant to a sale under its non-arm's-length contract (or other disposition of produced coal by other than an arm's-length contract), provided that those gross proceeds are within the range of the gross proceeds derived from, or paid under, comparable arm's-length contracts between buyers and sellers neither of whom is affiliated with the lessee for sales, purchases, or other dispositions of like-quality coal produced in the area. In evaluating the comparability of arm's-length contracts for the purposes of these regulations, the following factors shall be considered: price, time of execution, duration, market or markets served, terms, quality of coal, quantity, and such other factors as may be appropriate to reflect the value of the coal;

(ii) Prices reported for that coal to a public utility commission;

(iii) Prices reported for that coal to the Energy Information Administration of the Department of Energy;

(iv) Other relevant matters including, but not limited to, published or publicly available spot market prices, or information submitted by the lessee concerning circumstances unique to a particular lease operation or the salability of certain types of coal;

(v) If a reasonable value cannot be determined using paragraphs (c)(2)(i), (c)(2)(ii), (c)(2)(iii), or (c)(2)(iv) of this section, then a net-back method or any other reasonable method shall be used to determine value.

(3) When the value of coal is determined pursuant to paragraph (c)(2) of this section, that value determination shall be consistent with the provisions contained in paragraph (b)(5) of this section.

(d)(1) Where the value is determined pursuant to paragraph (c) of this section, that value does not require MMS' prior approval. However, the lessee shall retain all data relevant to the determination of royalty value. Such data shall be subject to review and audit, and MMS will direct a lessee to use a different value if it determines that the reported value is inconsistent with the requirements of these regulations.

(2) An Indian lessee will make available upon request to the authorized MMS or Indian representatives, or to the Inspector General of the Department of the Interior or other persons authorized to receive such information, arm's-length sales and sales quantity data for like-quality coal sold, purchased, or otherwise obtained by the lessee from the area.

(3) A lessee shall notify MMS if it has determined value pursuant to paragraphs (c)(2)(ii), (c)(2)(iii), (c)(2)(iv), or (c)(2)(v) of this section. The notification shall be by letter to the Associate Director for Minerals Revenue Management or his/her designee. The letter shall identify the valuation method to be used and contain a brief description of the procedure to be followed. The notification required by this section is a one-time notification due no later than the month the lessee first reports royalties on the Form MMS-4430 using a valuation method authorized by paragraphs (c)(2)(ii), (c)(2)(iii), (c)(2)(iv), or (c)(2)(v) of this section, and each time there is a change in a method under paragraphs (c)(2)(iv) or (c)(2)(v) of this section.

(e) If MMS determines that a lessee has not properly determined value, the lessee shall be liable for the difference, if any, between royalty payments made based upon the value it has used and the royalty payments that are due based upon the value established by MMS. The lessee shall also be liable for interest computed pursuant to 30 CFR 218.202. If the lessee is entitled to a credit, MMS will provide instructions for the taking of that credit.

(f) The lessee may request a value determination from MMS. In that event, the lessee shall propose to MMS a value determination method, and may use that method in determining value for royalty purposes until MMS issues its decision. The lessee shall submit all available data relevant to its proposal. MMS shall expeditiously determine the value based upon the lessee's proposal and any additional information MMS deems necessary. That determination shall remain effective for the period stated therein. After MMS issues its determination, the lessee shall make the adjustments in accordance with paragraph (e) of this section.

(g) Notwithstanding any other provisions of this section, under no circumstances shall the value for royalty purposes be less than the gross proceeds accruing to the lessee for the disposition of produced coal less applicable provisions of paragraph (b)(5) of this section and less applicable allowances

determined pursuant to §§206.457 through 206.461 and §206.464 of this subpart.

(h) The lessee is required to place coal in marketable condition at no cost to the Indian lessor. Where the value established pursuant to this section is determined by a lessee's gross proceeds, that value shall be increased to the extent that the gross proceeds has been reduced because the purchaser, or any other person, is providing certain services, the cost of which ordinarily is the responsibility of the lessee to place the coal in marketable condition.

(i) Value shall be based on the highest price a prudent lessee can receive through legally enforceable claims under its contract. Absent contract revision or amendment, if the lessee fails to take proper or timely action to receive prices or benefits to which it is entitled, it must pay royalty at a value based upon that obtainable price or benefit. Contract revisions or amendments shall be in writing and signed by all parties to an arm's-length contract, and may be retroactively applied to value for royalty purposes for a period not to exceed two years, unless MMS approves a longer period. If the lessee makes timely application for a price increase allowed under its contract but the purchaser refuses, and the lessee takes reasonable measures, which are documented, to force purchaser compliance, the lessee will owe no additional royalties unless or until monies or consideration resulting from the price increase are received. This paragraph shall not be construed to permit a lessee to avoid its royalty payment obligation in situations where a purchaser fails to pay, in whole or in part or timely, for a quantity of coal.

(j) Notwithstanding any provision in these regulations to the contrary, no review, reconciliation, monitoring, or other like process that results in a redetermination by MMS of value under this section shall be considered final or binding as against the Indian Tribes or allottees until the audit period is formally closed.

(k) Certain information submitted to MMS to support valuation proposals, including transportation, coal washing, or other allowances pursuant to §§206.457 through 206.461 and §206.464 of this subpart, is exempted from disclosure by the Freedom of Information Act, 5 U.S.C. 522. Any data specified by the Act to be privileged, confidential, or otherwise exempt shall be maintained in a confidential manner in accordance with applicable law and regulations. All requests for information about determinations made under this part are to be submitted in accordance with the Freedom of Information Act regulation of the Department of the Interior, 43 CFR part 2. Nothing in this section is intended to limit or diminish in any manner whatsoever the right of an Indian lessor to obtain any and all information as such lessor may be lawfully entitled from MMS or such lessor's lessee directly under the terms of the lease or applicable law.

[61 FR 5481, Feb. 12, 1996, as amended at 66 FR 45769, Aug. 30, 2001]

#### **§ 206.457 Washing allowances—general.**



[top](#)

(a) For ad valorem leases subject to §206.456 of this subpart, MMS shall, as authorized by this section, allow a deduction in determining value for royalty purposes for the reasonable, actual costs incurred to wash coal, unless the value determined pursuant to §206.456 of this subpart was based upon like-quality unwashed coal. Under no circumstances will the authorized washing allowance and the transportation allowance reduce the value for royalty purposes to zero.

(b) If MMS determines that a lessee has improperly determined a washing allowance authorized by this section, then the lessee shall be liable for any additional royalties, plus interest determined in accordance with 30 CFR 218.202, or shall be entitled to a credit, without interest.

(c) Lessees shall not disproportionately allocate washing costs to Indian leases.

(d) No cost normally associated with mining operations and which are necessary for placing coal in marketable condition shall be allowed as a cost of washing.

(e) Coal washing costs shall only be recognized as allowances when the washed coal is sold and royalties are reported and paid.

[61 FR 5481, Feb. 12, 1996, as amended at 64 FR 43289, Aug. 10, 1999]

#### **§ 206.458 Determination of washing allowances.**



[top](#)

(a) *Arm's-length contracts.* (1) For washing costs incurred by a lessee pursuant to an arm's-length contract, the washing allowance shall be the reasonable actual costs incurred by the lessee for washing the coal under that contract, subject to monitoring, review, audit, and possible future adjustment. MMS' prior approval is not required before a lessee may deduct costs incurred under an arm's-length contract. However, before any deduction may be taken, the lessee must submit a completed page one of Form MMS-4292, Coal Washing Allowance Report, in accordance with paragraph (c)(1) of this section. A washing 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-4292 is filed with MMS, unless MMS approves a longer period upon a showing of good cause by the lessee.

(2) In conducting reviews and audits, MMS will examine whether the contract reflects more than the consideration actually transferred either directly or indirectly from the lessee to the washer for the washing. If the contract reflects more than the total consideration paid, then MMS may require that the washing allowance be determined in accordance with paragraph (b) of this section.

(3) If MMS determines that the consideration paid pursuant to an arm's-length washing contract does not reflect the reasonable value of the washing because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then MMS shall require that the washing allowance be determined in accordance with paragraph (b) of this section. When MMS determines that the value of the washing may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's washing costs.

(4) Where the lessee's payments for washing under an arm's-length contract are not based on a dollar-per-unit basis, the lessee shall convert whatever consideration is paid to a dollar value equivalent. Washing allowances shall be expressed as a cost per ton of coal washed.

(b) *Non-arm's-length or no contract.* (1) If a lessee has a non-arm's-length contract or has no contract, including those situations where the lessee performs washing for itself, the washing allowance will be based upon the lessee's reasonable actual costs. All washing allowances deducted under a non-arm's-length or no contract situation are subject to monitoring, review, audit, and possible future adjustment. Prior MMS approval of washing allowances is not required for non-arm's-length or no contract situations. However, before any estimated or actual deduction may be taken, the lessee must submit a completed Form MMS-4292 in accordance with paragraph (c)(2) of this section. A washing 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-4292 is filed with MMS, unless MMS approves a longer period upon a showing of good cause by the lessee. MMS will monitor the allowance deduction to ensure that deductions are reasonable and allowable. When necessary or appropriate, MMS may direct a lessee to modify its actual washing allowance.

(2) The washing allowance for non-arm's-length or no contract situations shall be based upon the lessee's actual costs for washing during the reported period, including operating and maintenance expenses, overhead, and either depreciation and a return on undepreciated capital investment in accordance with paragraph (b)(2)(iv)(A) of this section, or a cost equal to the depreciable investment in the wash plant multiplied by the rate of return in accordance with paragraph (b)(2)(iv)(B) of this section. Allowable capital costs are generally those for depreciable fixed assets (including costs of delivery and installation of capital equipment) which are an integral part of the wash plant.

(i) Allowable operating expenses include: Operations supervision and engineering; operations labor; fuel; utilities; materials; ad valorem property taxes; rent; supplies; and any other directly allocable and attributable operating expense which the lessee can document.

(ii) Allowable maintenance expenses include: Maintenance of the wash plant; maintenance of equipment; maintenance labor; and other directly allocable and attributable maintenance expenses which the lessee can document.

(iii) Overhead attributable and allocable to the operation and maintenance of the wash plant is an allowable expense. State and Federal income taxes and severance taxes, including royalties, are not allowable expenses.

(iv) A lessee may use either paragraph (b)(2)(iv)(A) or (b)(2)(iv)(B) of this section. After a lessee has elected to use either method for a wash plant, the lessee may not later elect to change to the other alternative without approval of MMS.

(A) To compute depreciation, the lessee may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves which the wash plant services, whichever is appropriate, or a unit of production method. After an election is made, the lessee may not change methods without MMS approval. A change in ownership of a wash plant shall not alter the depreciation schedule established by the original operator/lessee for purposes of the allowance calculation. With or

without a change in ownership, a wash plant shall be depreciated only once. Equipment shall not be depreciated below a reasonable salvage value.

(B) MMS shall allow as a cost an amount equal to the allowable capital investment in the wash plant multiplied by the rate of return determined pursuant to paragraph (b)(2)(v) of this section. No allowance shall be provided for depreciation. This alternative shall apply only to plants first placed in service or acquired after March 1, 1989.

(v) The rate of return shall be the industrial rate associated with Standard and Poor's BBB rating. The rate of return shall be the monthly average rate as published in Standard and Poor's Bond Guide for the first month of the reporting period for which the allowance is applicable and shall be effective during the reporting period. The rate shall be redetermined at the beginning of each subsequent washing allowance reporting period (which is determined pursuant to paragraph (c)(2) of this section).

(3) The washing allowance for coal shall be determined based on the lessee's reasonable and actual cost of washing the coal. The lessee may not take an allowance for the costs of washing lease production that is not royalty bearing.

(c) *Reporting requirements* —(1) *Arm's-length contracts.* (i) With the exception of those washing allowances specified in paragraphs (c)(1)(v) and (c)(1)(vi) of this section, the lessee shall submit page one of the initial Form MMS-4292 prior to, or at the same time, as the washing allowance determined pursuant to an arm's-length contract is reported on Form MMS-4430, Solid Minerals Production and Royalty Report. A Form MMS-4292 received by the end of the month that the Form MMS-4430 is due shall be considered to be received timely.

(ii) The initial Form MMS-4292 shall be effective for a reporting period beginning the month that the lessee is first authorized to deduct a washing allowance and shall continue until the end of the calendar year, or until the applicable contract or rate terminates or is modified or amended, whichever is earlier.

(iii) After the initial reporting period and for succeeding reporting periods, lessees must submit page one of Form MMS-4292 within 3 months after the end of the calendar year, or after the applicable contract or rate terminates or is modified or amended, whichever is earlier, unless MMS approves a longer period (during which period the lessee shall continue to use the allowance from the previous reporting period).

(iv) MMS may require that a lessee submit arm's-length washing contracts and related documents. Documents shall be submitted within a reasonable time, as determined by MMS.

(v) Washing allowances which are based on arm's-length contracts and which are in effect at the time these regulations become effective will be allowed to continue until such allowances terminate. For the purposes of this section, only those allowances that have been approved by MMS in writing shall qualify as being in effect at the time these regulations become effective.

(vi) MMS may establish, in appropriate circumstances, reporting requirements that are different from the requirements of this section.

(2) *Non-arm's-length or no contract.* (i) With the exception of those washing allowances specified in paragraphs (c)(2)(v) and (c)(2)(vii) of this section, the lessee shall submit an initial Form MMS-4292 prior to, or at the same time as, the washing allowance determined pursuant to a non-arm's-length contract or no contract situation is reported on Form MMS-4430, Solid Minerals Production and Royalty Report. A Form MMS-4292 received by the end of the month that the Form MMS-4430 is due shall be considered to be timely received. The initial reporting may be based on estimated costs.

(ii) The initial Form MMS-4292 shall be effective for a reporting period beginning the month that the lessee first is authorized to deduct a washing allowance and shall continue until the end of the calendar year, or until the washing under the non-arm's-length contract or the no contract situation terminates, whichever is earlier.

(iii) For calendar-year reporting periods succeeding the initial reporting period, the lessee shall submit a completed Form MMS-4292 containing the actual costs for the previous reporting period. If coal washing is continuing, the lessee shall include on Form MMS-4292 its estimated costs for the next calendar year. The estimated coal washing allowance shall be based on the actual costs for the previous period plus or minus any adjustments which are based on the lessee's knowledge of decreases or increases which will affect the allowance. Form MMS-4292 must be received by MMS within 3 months after the end of the previous reporting period, unless MMS approves a longer period (during which period the lessee shall continue to use the allowance from the previous reporting period).

(iv) For new wash plants, the lessee's initial Form MMS-4292 shall include estimates of the allowable coal washing costs for the applicable period. Cost estimates shall be based upon the most recently

available operations data for the plant, or if such data are not available, the lessee shall use estimates based upon industry data for similar coal wash plants.

(v) Washing allowances based on non-arm's-length or no contract situations which are in effect at the time these regulations become effective will be allowed to continue until such allowances terminate. For the purposes of this section, only those allowances that have been approved by MMS in writing shall qualify as being in effect at the time these regulations become effective.

(vi) Upon request by MMS, the lessee shall submit all data used by the lessee to prepare its Forms MMS-4292. The data shall be provided within a reasonable period of time, as determined by MMS.

(vii) MMS may establish, in appropriate circumstances, reporting requirements which are different from the requirements of this section.

(3) MMS may establish coal washing allowance reporting dates for individual leases different from those specified in this subpart in order to provide more effective administration. Lessees will be notified of any change in their reporting period.

(4) Washing allowances must be reported as a separate line on the Form MMS-4430, unless MMS approves a different reporting procedure.

(d) *Interest assessments for incorrect or late reports and failure to report.* (1) If a lessee deducts a washing allowance on its Form MMS-4430 without complying with the requirements of this section, the lessee shall be liable for interest on the amount of such deduction until the requirements of this section are complied with. The lessee also shall repay the amount of any allowance which is disallowed by this section.

(2) If a lessee erroneously reports a washing allowance which results in an underpayment of royalties, interest shall be paid on the amount of that underpayment.

(3) Interest required to be paid by this section shall be determined in accordance with 30 CFR 218.202.

(e) *Adjustments.* (1) If the actual coal washing allowance is less than the amount the lessee has taken on Form MMS-4430 for each month during the allowance form reporting period, the lessee shall be required to pay additional royalties due plus interest computed pursuant to 30 CFR 218.202, retroactive to the first month the lessee is authorized to deduct a washing allowance. If the actual washing allowance is greater than the amount the lessee has estimated and taken during the reporting period, the lessee shall be entitled to a credit, without interest.

(2) The lessee must submit a corrected Form MMS-4430 to reflect actual costs, together with any payment, in accordance with instructions provided by MMS.

(f) *Other washing cost determinations.* The provisions of this section shall apply to determine washing costs when establishing value using a net-back valuation procedure or any other procedure that requires deduction of washing costs.

[61 FR 5481, Feb. 12, 1996, as amended at 66 FR 45769, Aug. 30, 2001]

#### § 206.459 Allocation of washed coal.



[top](#)

(a) When coal is subjected to washing, the washed coal must be allocated to the leases from which it was extracted.

(b) When the net output of coal from a washing plant is derived from coal obtained from only one lease, the quantity of washed coal allocable to the lease will be based on the net output of the washing plant.

(c) When the net output of coal from a washing plant is derived from coal obtained from more than one lease, unless determined otherwise by BLM, the quantity of net output of washed coal allocable to each lease will be based on the ratio of measured quantities of coal delivered to the washing plant and washed from each lease compared to the total measured quantities of coal delivered to the washing plant and washed.

#### § 206.460 Transportation allowances—general.



(a) For ad valorem leases subject to §206.456 of this subpart, where the value for royalty purposes has been determined at a point remote from the lease or mine, MMS shall, as authorized by this section, allow a deduction in determining value for royalty purposes for the reasonable, actual costs incurred to:

- (1) Transport the coal from an Indian lease to a sales point which is remote from both the lease and mine; or
- (2) Transport the coal from an Indian lease to a wash plant when that plant is remote from both the lease and mine and, if applicable, from the wash plant to a remote sales point. In-mine transportation costs shall not be included in the transportation allowance.

(b) Under no circumstances will the authorized washing allowance and the transportation allowance reduce the value for royalty purposes to zero.

(c)(1) When coal transported from a mine to a wash plant is eligible for a transportation allowance in accordance with this section, the lessee is not required to allocate transportation costs between the quantity of clean coal output and the rejected waste material. The transportation allowance shall be authorized for the total production which is transported. Transportation allowances shall be expressed as a cost per ton of cleaned coal transported.

(2) For coal that is not washed at a wash plant, the transportation allowance shall be authorized for the total production which is transported. Transportation allowances shall be expressed as a cost per ton of coal transported.

(3) Transportation costs shall only be recognized as allowances when the transported coal is sold and royalties are reported and paid.

(d) If, after a review and/or audit, MMS determines that a lessee has improperly determined a transportation allowance authorized by this section, then the lessee shall pay any additional royalties, plus interest, determined in accordance with 30 CFR 218.202, or shall be entitled to a credit, without interest.

(e) Lessees shall not disproportionately allocate transportation costs to Indian leases.

[61 FR 5481, Feb. 12, 1996, as amended at 64 FR 43289, Aug. 10, 1999]

#### **§ 206.461 Determination of transportation allowances.**



(a) *Arm's-length contracts.* (1) For transportation costs incurred by a lessee pursuant to an arm's-length contract, the transportation allowance shall be the reasonable, actual costs incurred by the lessee for transporting the coal under that contract, subject to monitoring, review, audit, and possible future adjustment. MMS' prior approval is not required before a lessee may deduct costs incurred under an arm's-length contract. However, before any deduction may be taken, the lessee must submit a completed page one of Form MMS-4293, Coal Transportation Allowance Report, in accordance with paragraph (c)(1) of this section. A transportation 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-4293 is filed with MMS, unless MMS approves a longer period upon a showing of good cause by the lessee.

(2) In conducting reviews and audits, MMS will examine whether the contract reflects more than the consideration actually transferred either directly or indirectly from the lessee to the transporter for the transportation. If the contract reflects more than the total consideration paid, then MMS may require that the transportation allowance be determined in accordance with paragraph (b) of this section.

(3) If MMS determines that the consideration paid pursuant to an arm's-length transportation contract does not reflect the reasonable value of the transportation because of misconduct by or between the contracting parties, or because the lessee otherwise has breached its duty to the lessor to market the production for the mutual benefit of the lessee and the lessor, then MMS shall require that the transportation allowance be determined in accordance with paragraph (b) of this section. When MMS determines that the value of the transportation may be unreasonable, MMS will notify the lessee and give the lessee an opportunity to provide written information justifying the lessee's transportation costs.

(4) Where the lessee's payments for transportation under an arm's-length contract are not based on a dollar-per-unit basis, the lessee shall convert whatever consideration is paid to a dollar value equivalent for the purposes of this section.

(b) *Non-arm's-length or no contract.* (1) If a lessee has a non-arm's-length contract or has no contract, including those situations where the lessee performs transportation services for itself, the transportation allowance will be based upon the lessee's reasonable actual costs. All transportation allowances deducted under a non-arm's-length or no contract situation are subject to monitoring, review, audit, and possible future adjustment. Prior MMS approval of transportation allowances is not required for non-arm's-length or no contract situations. However, before any estimated or actual deduction may be taken, the lessee must submit a completed Form MMS-4293 in accordance with paragraph (c)(2) of this section. A transportation 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-4293 is filed with MMS, unless MMS approves a longer period upon a showing of good cause by the lessee. MMS will monitor the allowance deductions to ensure that deductions are reasonable and allowable. When necessary or appropriate, MMS may direct a lessee to modify its estimated or actual transportation allowance deduction.

(2) The transportation allowance for non-arm's-length or no contract situations shall be based upon the lessee's actual costs for transportation during the reporting period, including operating and maintenance expenses, overhead, and either depreciation and a return on undepreciated capital investment in accordance with paragraph (b)(2)(iv)(A) of this section, or a cost equal to the depreciable investment in the transportation system multiplied by the rate of return in accordance with paragraph (b)(2)(iv)(B) of this section. Allowable capital costs are generally those for depreciable fixed assets (including costs of delivery and installation of capital equipment) which are an integral part of the transportation system.

(i) Allowable operating expenses include: Operations supervision and engineering; operations labor; fuel; utilities; materials; ad valorem property taxes; rent; supplies; and any other directly allocable and attributable operating expense which the lessee can document.

(ii) Allowable maintenance expenses include: Maintenance of the transportation system; maintenance of equipment; maintenance labor; and other directly allocable and attributable maintenance expenses which the lessee can document.

(iii) Overhead attributable and allocable to the operation and maintenance of the transportation system is an allowable expense. State and Federal income taxes and severance taxes and other fees, including royalties, are not allowable expenses.

(iv) A lessee may use either paragraph (b)(2)(iv)(A) or paragraph (b)(2)(iv)(B) of this section. After a lessee has elected to use either method for a transportation system, the lessee may not later elect to change to the other alternative without approval of MMS.

(A) To compute depreciation, the lessee may elect to use either a straight-line depreciation method based on the life of equipment or on the life of the reserves which the transportation system services, whichever is appropriate, or a unit of production method. After an election is made, the lessee may not change methods without MMS approval. A change in ownership of a transportation system shall not alter the depreciation schedule established by the original transporter/lessee for purposes of the allowance calculation. With or without a change in ownership, a transportation system shall be depreciated only once. Equipment shall not be depreciated below a reasonable salvage value.

(B) MMS shall allow as a cost an amount equal to the allowable capital investment in the transportation system multiplied by the rate of return determined pursuant to paragraph (b)(2)(B)(v) of this section. No allowance shall be provided for depreciation. This alternative shall apply only to transportation facilities first placed in service or acquired after March 1, 1989.

(v) The rate of return shall be the industrial rate associated with Standard and Poor's BBB rating. The rate of return shall be the monthly average as published in Standard and Poor's Bond Guide for the first month of the reporting period of which the allowance is applicable and shall be effective during the reporting period. The rate shall be redetermined at the beginning of each subsequent transportation allowance reporting period (which is determined pursuant to paragraph (c)(2) of this section).

(3) A lessee may apply to MMS for exception from the requirement that it compute actual costs in accordance with paragraphs (b)(1) and (b)(2) of this section. MMS will grant the exception only if the lessee has a rate for the transportation approved by a Federal agency for Indian leases. MMS shall deny the exception request if it determines that the rate is excessive as compared to arm's-length transportation charges by systems, owned by the lessee or others, providing similar transportation services in that area. If there are no arm's-length transportation charges, MMS shall deny the exception request if:

(i) No Federal regulatory agency cost analysis exists and the Federal regulatory agency has declined to

investigate pursuant to MMS timely objections upon filing; and

(ii) The rate significantly exceeds the lessee's actual costs for transportation as determined under this section.

(c) *Reporting requirements* —(1) *Arm's-length contracts.* (i) With the exception of those transportation allowances specified in paragraphs (c)(1)(v) and (c)(1)(vi) of this section, the lessee shall submit page one of the initial Form MMS-4293 prior to, or at the same time as, the transportation allowance determined pursuant to an arm's-length contract is reported on Form MMS-4430, Solid Minerals Production and Royalty Report.

(ii) The initial Form MMS-4293 shall be effective for a reporting period beginning the month that the lessee is first authorized to deduct a transportation allowance and shall continue until the end of the calendar year, or until the applicable contract or rate terminates or is modified or amended, whichever is earlier.

(iii) After the initial reporting period and for succeeding reporting periods, lessees must submit page one of Form MMS-4293 within 3 months after the end of the calendar year, or after the applicable contract or rate terminates or is modified or amended, whichever is earlier, unless MMS approves a longer period (during which period the lessee shall continue to use the allowance from the previous reporting period). Lessees may request special reporting procedures in unique allowance reporting situations, such as those related to spot sales.

(iv) MMS may require that a lessee submit arm's-length transportation contracts, production agreements, operating agreements, and related documents. Documents shall be submitted within a reasonable time, as determined by MMS.

(v) Transportation allowances that are based on arm's-length contracts and which are in effect at the time these regulations become effective will be allowed to continue until such allowances terminate. For the purposes of this section, only those allowances that have been approved by MMS in writing shall qualify as being in effect at the time these regulations become effective.

(vi) MMS may establish, in appropriate circumstances, reporting requirements that are different from the requirements of this section.

(2) *Non-arm's-length or no contract.* (i) With the exception of those transportation allowances specified in paragraphs (c)(2)(v) and (c)(2)(vii) of this section, the lessee shall submit an initial Form MMS-4293 prior to, or at the same time as, the transportation allowance determined pursuant to a non-arm's-length contract or no contract situation is reported on Form MMS-4430, Solid Minerals Production and Royalty Report. The initial report may be based on estimated costs.

(ii) The initial Form MMS-4293 shall be effective for a reporting period beginning the month that the lessee first is authorized to deduct a transportation allowance and shall continue until the end of the calendar year, or until the transportation under the non-arm's-length contract or the no contract situation terminates, whichever is earlier.

(iii) For calendar-year reporting periods succeeding the initial reporting period, the lessee shall submit a completed Form MMS-4293 containing the actual costs for the previous reporting period. If the transportation is continuing, the lessee shall include on Form MMS-4293 its estimated costs for the next calendar year. The estimated transportation allowance shall be based on the actual costs for the previous reporting period plus or minus any adjustments that are based on the lessee's knowledge of decreases or increases that will affect the allowance. Form MMS-4293 must be received by MMS within 3 months after the end of the previous reporting period, unless MMS approves a longer period (during which period the lessee shall continue to use the allowance from the previous reporting period).

(iv) For new transportation facilities or arrangements, the lessee's initial Form MMS-4293 shall include estimates of the allowable transportation costs for the applicable period. Cost estimates shall be based upon the most recently available operations data for the transportation system, or, if such data are not available, the lessee shall use estimates based upon industry data for similar transportation systems.

(v) Non-arm's-length contract or no contract-based transportation allowances that are in effect at the time these regulations become effective will be allowed to continue until such allowances terminate. For purposes of this section, only those allowances that have been approved by MMS in writing shall qualify as being in effect at the time these regulations become effective.

(vi) Upon request by MMS, the lessee shall submit all data used to prepare its Form MMS-4293. The data shall be provided within a reasonable period of time, as determined by MMS.

(vii) MMS may establish, in appropriate circumstances, reporting requirements that are different from the requirements of this section.

(viii) If the lessee is authorized to use its Federal-agency-approved rate as its transportation cost in accordance with paragraph (b)(3) of this section, it shall follow the reporting requirements of paragraph (c)(1) of this section.

(3) MMS may establish reporting dates for individual lessees different than those specified in this paragraph in order to provide more effective administration. Lessees will be notified as to any change in their reporting period.

(4) Transportation allowances must be reported as a separate line item on Form MMS-4430, unless MMS approves a different reporting procedure.

(d) *Interest assessments for incorrect or late reports and failure to report.* (1) If a lessee deducts a transportation allowance on its Form MMS-4430 without complying with the requirements of this section, the lessee shall be liable for interest on the amount of such deduction until the requirements of this section are complied with. The lessee also shall repay the amount of any allowance which is disallowed by this section.

(2) If a lessee erroneously reports a transportation allowance which results in an underpayment of royalties, interest shall be paid on the amount of that underpayment.

(3) Interest required to be paid by this section shall be determined in accordance with 30 CFR 218.202.

(e) *Adjustments.* (1) If the actual transportation allowance is less than the amount the lessee has taken on Form MMS-4430 for each month during the allowance form reporting period, the lessee shall be required to pay additional royalties due plus interest, computed pursuant to 30 CFR 218.202, retroactive to the first month the lessee is authorized to deduct a transportation allowance. If the actual transportation allowance is greater than the amount the lessee has estimated and taken during the reporting period, the lessee shall be entitled to a credit, without interest.

(2) The lessee must submit a corrected Form MMS-4430 to reflect actual costs, together with any payment, in accordance with instructions provided by MMS.

(f) *Other transportation cost determinations.* The provisions of this section shall apply to determine transportation costs when establishing value using a net-back valuation procedure or any other procedure that requires deduction of transportation costs.

[61 FR 5481, Feb. 12, 1996, as amended at 64 FR 43289, Aug. 10, 1999; 66 FR 45769, Aug. 30, 2001]

## § 206.462 [Reserved]



[top](#)

## § 206.463 In-situ and surface gasification and liquefaction operations.



[top](#)

If an ad valorem Federal coal lease is developed by in-situ or surface gasification or liquefaction technology, the lessee shall propose the value of coal for royalty purposes to MMS. MMS will review the lessee's proposal and issue a value determination. The lessee may use its proposed value until MMS issues a value determination.

[61 FR 5481, Feb. 12, 1996, as amended at 64 FR 43289, Aug. 10, 1999]

## § 206.464 Value enhancement of marketable coal.



[top](#)

If, prior to use, sale, or other disposition, the lessee enhances the value of coal after the coal has been placed in marketable condition in accordance with §206.456(h) of this subpart, the lessee shall notify MMS that such processing is occurring or will occur. The value of that production shall be determined as

follows:

(a) A value established for the feedstock coal in marketable condition by application of the provisions of §206.456(c)(2) (i) through (iv) of this subpart; or,

(b) In the event that a value cannot be established in accordance with paragraph (a) of this section, then the value of production will be determined in accordance with §206.456(c)(2)(v) of this subpart and the value shall be the lessee's gross proceeds accruing from the disposition of the enhanced product, reduced by MMS-approved processing costs and procedures including a rate of return on investment equal to two times the Standard and Poor's BBB bond rate applicable under §206.458(b)(2)(v) of this subpart.

[61 FR 5481, Feb. 12, 1996, as amended 64 FR 43289, Aug. 10, 1999]

[Browse Previous](#) | [Browse Next](#)

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[Section 508 / Accessibility](#)

[Home Page](#) > [Executive Branch](#) > [Code of Federal Regulations](#) > [Electronic Code of Federal Regulations](#)

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**Title 43: Public Lands: Interior**[Browse Previous](#) | [Browse Next](#)**PART 3160—ONSHORE OIL AND GAS OPERATIONS****Section Contents****Subpart 3160—Onshore Oil and Gas Operations: General**

- [§ 3160.0-1 Purpose.](#)
- [§ 3160.0-2 Policy.](#)
- [§ 3160.0-3 Authority.](#)
- [§ 3160.0-4 Objectives.](#)
- [§ 3160.0-5 Definitions.](#)
- [§ 3160.0-7 Cross references.](#)
- [§ 3160.0-9 Information collection.](#)

**Subpart 3161—Jurisdiction and Responsibility**

- [§ 3161.1 Jurisdiction.](#)
- [§ 3161.2 Responsibility of the authorized officer.](#)
- [§ 3161.3 Inspections.](#)

**Subpart 3162—Requirements for Operating Rights Owners and Operators**

- [§ 3162.1 General requirements.](#)
- [§ 3162.2 Drilling, producing, and drainage obligations.](#)
  - [§ 3162.2-1 Drilling and producing obligations.](#)
  - [§ 3162.2-2 What steps may BLM take to avoid uncompensated drainage of Federal or Indian mineral resources?](#)
  - [§ 3162.2-3 When am I responsible for protecting my Federal or Indian lease from drainage?](#)
  - [§ 3162.2-4 What protective action may BLM require the lessee to take to protect the leases from drainage?](#)
  - [§ 3162.2-5 Must I take protective action when a protective well would be uneconomic?](#)
  - [§ 3162.2-6 When will I have constructive notice that drainage may be occurring?](#)
  - [§ 3162.2-7 Who is liable for drainage if more than one person holds undivided interests in the record title or operating rights for the same lease?](#)
  - [§ 3162.2-8 Does my responsibility for drainage protection end when I assign or transfer my lease interest?](#)
  - [§ 3162.2-9 What is my duty to inquire about the potential for drainage and inform BLM of my findings?](#)
  - [§ 3162.2-10 Will BLM notify me when it determines that drainage is occurring?](#)
  - [§ 3162.2-11 How soon after I know of the likelihood of drainage must I take protective action?](#)
  - [§ 3162.2-12 If I hold an interest in a lease, for what period will the Department assess compensatory royalty against me?](#)
  - [§ 3162.2-13 If I acquire an interest in a lease that is being drained, will the Department assess me for compensatory royalty?](#)
  - [§ 3162.2-14 May I appeal BLM's decision to require drainage protective measures?](#)
  - [§ 3162.2-15 Who has the burden of proof if I appeal BLM's drainage determination?](#)

- § 3162.3 Conduct of operations.
- § 3162.3-1 Drilling applications and plans.
- § 3162.3-2 Subsequent well operations.
- § 3162.3-3 Other lease operations.
- § 3162.3-4 Well abandonment.
- § 3162.4 Records and reports.
- § 3162.4-1 Well records and reports.
- § 3162.4-2 Samples, tests, and surveys.
- § 3162.4-3 Monthly report of operations (Form 3160-6).
- § 3162.5 Environment and safety.
- § 3162.5-1 Environmental obligations.
- § 3162.5-2 Control of wells.
- § 3162.5-3 Safety precautions.
- § 3162.6 Well and facility identification.
- § 3162.7 Measurement, disposition, and protection of production.
- § 3162.7-1 Disposition of production.
- § 3162.7-2 Measurement of oil.
- § 3162.7-3 Measurement of gas.
- § 3162.7-4 Royalty rates on oil; sliding and step-scale leases (public land only).
- § 3162.7-5 Site security on Federal and Indian (except Osage) oil and gas leases.

#### **Subpart 3163—Noncompliance, Assessments, and Penalties**

- § 3163.1 Remedies for acts of noncompliance.
- § 3163.2 Civil penalties.
- § 3163.3 Criminal penalties.
- § 3163.4 Failure to pay.
- § 3163.5 Assessments and civil penalties.
- § 3163.6 Injunction and specific performance.

#### **Subpart 3164—Special Provisions**

- § 3164.1 Onshore Oil and Gas Orders.
- § 3164.2 NTL's and other implementing procedures.
- § 3164.3 Surface rights.
- § 3164.4 Damages on restricted Indian lands.

#### **Subpart 3165—Relief, Conflicts, and Appeals**

- § 3165.1 Relief from operating and producing requirements.
- § 3165.1-1 Relief from royalty and rental requirements.
- § 3165.2 Conflicts between regulations.
- § 3165.3 Notice, State Director review and hearing on the record.
- § 3165.4 Appeals.

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**Authority:** 25 U.S.C. 396d and 2107; 30 U.S.C. 189, 306, 359, and 1751; and 43 U.S.C. 1732(b), 1733 and 1740.

**Source:** 47 FR 47765, Oct. 27, 1982, unless otherwise noted. Redesignated at 48 FR 36583, Aug. 12, 1983.

#### **Subpart 3160—Onshore Oil and Gas Operations: General**



[top](#)

##### **§ 3160.0-1 Purpose.**



[top](#)

The regulations in this part govern operations associated with the exploration, development and production of oil and gas deposits from—

(a) Leases issued or approved by the United States;

(b) Restricted Indian land leases; and

(c) Those leases under the jurisdiction of the Secretary of the Interior by law or administrative arrangement including the National Petroleum Reserve-Alaska (NPR-A). However, provisions relating to suspension and royalty reductions contained in subpart 3165 of this part do not apply to the NPR-A.

[67 FR 17894, Apr. 11, 2002]

#### **§ 3160.0-2 Policy.**



[top](#)

The regulations in this part are administered under the direction of the Director of the Bureau of Land Management; except that as to lands within naval petroleum reserves, they shall be administered under such official as the Secretary of Energy shall designate.

[48 FR 36584, Aug. 12, 1983]

#### **§ 3160.0-3 Authority.**



[top](#)

The Mineral Leasing Act, as amended and supplemented (30 U.S.C. 181 *et seq.*), the Act of May 21, 1930 (30 U.S.C. 301–306), the Mineral Leasing Act for Acquired Lands, as amended (30 U.S.C. 351–359), the Act of March 3, 1909, as amended (25 U.S.C. 396), the Act of May 11, 1938, as amended (25 U.S.C. 396a–396q), the Act of February 28, 1891, as amended (25 U.S.C. 397), the Act of May 29, 1924 (25 U.S.C. 398), the Act of March 3, 1927 (25 U.S.C. 398a–398e), the Act of June 30, 1919, as amended (25 U.S.C. 399), R.S. §441 (43 U.S.C. 1457), the Attorney General's Opinion of April 2, 1941 (40 Op Atty. Gen. 41), the Federal Property and Administrative Services Act of 1949, as amended (40 U.S.C. 471 *et seq.*), the National Environmental Policy Act of 1969, as amended (42 U.S.C. 4321 *et seq.*), the Act of December 12, 1980 (94 Stat. 2964), the Combined Hydrocarbon Leasing Act of 1981 (95 Stat. 1070), the Federal Oil and Gas Royalty Management Act of 1982 (30 U.S.C. 1701), the Indian Mineral Development Act of 1982 (25 U.S.C. 2102), and Order Number 3087, dated December 3, 1982, as amended on February 7, 1983 (48 FR 8983) under which the Secretary consolidated and transferred the onshore minerals management functions of the Department, except mineral revenue functions and the responsibility for leasing of restricted Indian lands, to the Bureau of Land Management.

[48 FR 36583, Aug. 12, 1983]

#### **§ 3160.0-4 Objectives.**



[top](#)

The objective of these regulations is to promote the orderly and efficient exploration, development and production of oil and gas.

[48 FR 36583, Aug. 12, 1983]

#### **§ 3160.0-5 Definitions.**



[top](#)

As used in this part, the term:

*Authorized representative* means any entity or individual authorized by the Secretary to perform duties by cooperative agreement, delegation or contract.

*Avoidably lost* means the venting or flaring of produced gas without the prior authorization, approval, ratification or acceptance of the authorized officer and the loss of produced oil or gas when the authorized officer determines that such loss occurred as a result of:

- (1) Negligence on the part of the operator; or
- (2) The failure of the operator to take all reasonable measures to prevent and/or control the loss; or
- (3) The failure of the operator to comply fully with the applicable lease terms and regulations, applicable orders and notices, or the written orders of the authorized officer; or
- (4) Any combination of the foregoing.

*Drainage* means the migration of hydrocarbons, inert gases (other than helium), or associated resources caused by production from other wells.

*Federal lands* means all lands and interests in lands owned by the United States which are subject to the mineral leasing laws, including mineral resources or mineral estates reserved to the United States in the conveyance of a surface or nonmineral estate.

*Fresh water* means water containing not more than 1,000 ppm of total dissolved solids, provided that such water does not contain objectionable levels of any constituent that is toxic to animal, plant or aquatic life, unless otherwise specified in applicable notices or orders.

*Knowingly or willfully* means a violation that constitutes the voluntary or conscious performance of an act that is prohibited or the voluntary or conscious failure to perform an act or duty that is required. It does not include performances or failures to perform that are honest mistakes or merely inadvertent. It includes, but does not require, performances or failures to perform that result from a criminal or evil intent or from a specific intent to violate the law. The knowing or willful nature of conduct may be established by plain indifference to or reckless disregard of the requirements of the law, regulations, orders, or terms of the lease. A consistent pattern of performance or failure to perform also may be sufficient to establish the knowing or willful nature of the conduct, where such consistent pattern is neither the result of honest mistakes or mere inadvertency. Conduct that is otherwise regarded as being knowing or willful is rendered neither accidental nor mitigated in character by the belief that the conduct is reasonable or legal.

*Lease* means any 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, extraction of or removal of oil or gas.

*Lease site* means any lands, including the surface of a severed mineral estate, on which exploration for, or extraction and removal of, oil or gas is authorized under a lease.

*Lessee* means any person holding record title or owning operating rights in a lease issued or approved by the United States.

*Lessor* means the party to a lease who holds legal or beneficial title to the mineral estate in the leased lands.

*Major violation* means noncompliance that causes or threatens immediate, substantial, and adverse impacts on public health and safety, the environment, production accountability, or royalty income.

*Maximum ultimate economic recovery* means the recovery of oil and gas from leased lands which a prudent operator could be expected to make from that field or reservoir given existing knowledge of reservoir and other pertinent facts and utilizing common industry practices for primary, secondary or tertiary recovery operations.

*Minor violation* means noncompliance that does not rise to the level of a *major violation*.

*New or resumed production under section 102(b)(3) of the Federal Oil and Gas Royalty Management Act* means the date on which a well commences production, or resumes production after having been off production for more than 90 days, and is to be construed as follows:

- (1) For an oil well, the date on which liquid hydrocarbons are first sold or shipped from a temporary storage facility, such as a test tank, or the date on which liquid hydrocarbons are first produced into a permanent storage facility, whichever first occurs; and
- (2) For a gas well, the date on which gas is first measured through sales metering facilities or the date on which associated liquid hydrocarbons are first sold or shipped from a temporary storage facility, whichever first occurs. For purposes of this provision, a gas well shall not be considered to have been

off of production unless it is incapable of production.

*Notice to lessees and operators (NTL)* means a written notice issued by the authorized officer. NTL's implement the regulations in this part and operating orders, and serve as instructions on specific item(s) of importance within a State, District, or Area.

*Onshore oil and gas order* means a formal numbered order issued by the Director that implements and supplements the regulations in this part.

*Operating rights owner* means a person who owns operating rights in a lease. A record title holder may also be an operating rights owner in a lease if it did not transfer all of its operating rights.

*Operator* means any person or entity including but not limited to the lessee or operating rights owner, who has stated in writing to the authorized officer that it is responsible under the terms and conditions of the lease for the operations conducted on the leased lands or a portion thereof.

*Paying well* means a well that is capable of producing oil or gas of sufficient value to exceed direct operating costs and the costs of lease rentals or minimum royalty.

*Person* means any individual, firm, corporation, association, partnership, consortium or joint venture.

*Production in paying quantities* means production from a lease of oil and/or gas of sufficient value to exceed direct operating costs and the cost of lease rentals or minimum royalties.

*Protective well* means a well drilled or modified to prevent or offset drainage of oil and gas resources from its Federal or Indian lease.

*Record title holder* means the person(s) to whom BLM or an Indian lessor issued a lease or approved the assignment of record title in a lease.

*Superintendent* means the superintendent of an Indian Agency, or other officer authorized to act in matters of record and law with respect to oil and gas leases on restricted Indian lands.

*Surface use plan of operations* means a plan for surface use, disturbance, and reclamation.

*Waste of oil or gas* means any act or failure to act by the operator that is not sanctioned by the authorized officer as necessary for proper development and production and which results in: (1) A reduction in the quantity or quality of oil and gas ultimately producible from a reservoir under prudent and proper operations; or (2) avoidable surface loss of oil or gas.

[53 FR 17362, May 16, 1988, as amended at 53 FR 22846, June 17, 1988; 66 FR 1892, Jan. 10, 2001]

#### **§ 3160.0-7 Cross references.**



[top](#)

25 CFR parts 221, 212, 213, and 227

30 CFR Group 200

40 CFR Chapter V

43 CFR parts 2, 4, and 1820 and Groups 3000, 3100 and 3500

[48 FR 36584, Aug. 12, 1983]

#### **§ 3160.0-9 Information collection.**



[top](#)

(a) The information collection requirements contained in §§3162.3, 3162.3-1, 3162.3-2, 3162.3-3, 3162.3-4, 3162.4-1, 3162.4-2, 3162.5-1, 3162.5-2, 3162.5-3, 3162.6, 3162.7-1, 3162.7-2, 3162.7-3,

3162.7-5, 3164.3, 3165.1, and 3165.3 have been approved by the Office of Management and Budget under 44 U.S.C. 3507 and assigned clearance Number 1004-0134. The information may be collected from some operators either to provide data so that proposed operations may be approved or to enable the monitoring of compliance with granted approvals. The information will be used to grant approval to begin or alter operations or to allow operations to continue. The obligation to respond is required to obtain benefits under the lease.

(b) Public reporting burden for this information is estimated to average 0.4962 hours per response, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing the burden, to the Information Collection Clearance Officer (783), Bureau of Land Management, Washington, DC 20240, and the Office of Management and Budget, Paperwork Reduction Project, 1004-0134, Washington, DC 20503.

(c)(1) The information collection requirements contained in part 3160 have been approved by the Office of Management and Budget under 44 U.S.C. 3507 and assigned the following Clearance Numbers:

#### Operating Forms

Form No.	Name and filing date	OMB No.
3160-3	Application for Permit to Drill, Deepen, or Plug Back—Filed 30 days prior to planned action	1004-0136
3160-4	With Completion of Recompletion Report and Log—Due 30 days after well completion	1004-0137
3160-5	Sundry Notice and Reports on Wells—Subsequent report due 30 days after operations completed	1004-0135

The information will be used to manage Federal and Indian oil and gas leases. It will be used to allow evaluation of the technical, safety, and environmental factors involved with drilling and producing oil and gas on Federal and Indian oil and gas leases. Response is mandatory only if the operator elects to initiate drilling, completion, or subsequent operations on an oil and gas well, in accordance with 30 U.S.C. 181 *et seq.*

(2) Public reporting burden for this information is estimated to average 25 minutes per response for clearance number 1004-0135, 30 minutes per response for clearance number 1004-0136, and 1 hour per response for clearance number 1004-0137, including the time for reviewing instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collection of information. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing the burden, to the Information Collection Clearance Officer (783), Bureau of Land Management, Washington, DC 20240, and the Office of Management and Budget, Paperwork Reduction Project, 1004-0135, 1004-0136, or 1004-0137, as appropriate, Washington, DC 20503.

(d) There are many leases and agreements currently in effect, and which will remain in effect, involving both Federal and Indian oil and gas leases which specifically refer to the United States Geological Survey, USGS, Minerals Management Service, MMS, or Conservation Division. These leases and agreements also often specifically refer to various officers such as Supervisor, Conservation Manager, Deputy Conservation Manager, Minerals Manager, and Deputy Minerals Manager. In addition, many leases and agreements specifically refer to 30 CFR part 221 or specific sections thereof, which has been redesignated as 43 CFR part 3160. Those references shall now be read in the context of Secretarial Order 3087 and now mean either the Bureau of Land Management or Minerals Management Service, as appropriate.

[57 FR 3024, Jan. 27, 1992]

#### Subpart 3161—Jurisdiction and Responsibility



top

#### § 3161.1 Jurisdiction.

[top](#)

(a) All operations conducted on a Federal or Indian oil and gas lease by the operator are subject to the regulations in this part.

(b) Regulations in this part relating to site security, measurement, reporting of production and operations, and assessments or penalties for noncompliance with such requirements are applicable to all wells and facilities on State or privately-owned mineral lands committed to a unit or communitization agreement which affects Federal or Indian interests, notwithstanding any provision of a unit or communitization agreement to the contrary.

[52 FR 5391, Feb. 20, 1987, as amended at 53 FR 17362, May 16, 1988]

## **§ 3161.2 Responsibility of the authorized officer.**

[top](#)

The authorized officer is authorized and directed to approve unitization, communitization, gas storage and other contractual agreements for Federal lands; to assess compensatory royalty; to approve suspensions of operations or production, or both; to issue NTL's; to approve and monitor other operator proposals for drilling, development or production of oil and gas; to perform administrative reviews; to impose monetary assessments or penalties; to provide technical information and advice relative to oil and gas development and operations on Federal and Indian lands; to enter into cooperative agreements with States, Federal agencies and Indian tribes relative to oil and gas development and operations; to approve, inspect and regulate the operations that are subject to the regulations in this part; to require compliance with lease terms, with the regulations in this title and all other applicable regulations promulgated under the cited laws; and to require that all operations be conducted in a manner which protects other natural resources and the environmental quality, protects life and property and results in the maximum ultimate recovery of oil and gas with minimum waste and with minimum adverse effect on the ultimate recovery of other mineral resources. The authorized officer may issue written or oral orders to govern specific lease operations. Any such oral orders shall be confirmed in writing by the authorized officer within 10 working days from issuance thereof. Before approving operations on leasehold, the authorized officer shall determine that the lease is in effect, that acceptable bond coverage has been provided and that the proposed plan of operations is sound both from a technical and environmental standpoint.

[48 FR 36584, Aug. 12, 1983, as amended at 52 FR 5391, Feb. 20, 1987; 53 FR 17362, May 16, 1988]

## **§ 3161.3 Inspections.**

[top](#)

(a) The authorized officer shall establish procedures to ensure that each Federal and Indian lease site which is producing or is expected to produce significant quantities of oil or gas in any year or which has a history of noncompliance with applicable provisions of law or regulations, lease terms, orders or directives shall be inspected at least once annually. Similarly, each lease site on non-Federal or non-Indian lands subject to a formal agreement such as a unit or communitization agreement which has been approved by the Department of the Interior and in which the United States or the Indian lessors share in production shall be inspected annually whenever any of the foregoing criteria are applicable.

(b) In accomplishing the inspections, the authorized officer may utilize Bureau personnel, may enter into cooperative agreements with States or Indian Tribes, may delegate the inspection authority to any State, or may contract with any non-Federal Government entities. Any cooperative agreement, delegation or contractual arrangement shall not be effective without concurrence of the Secretary and shall include applicable provisions of the Federal Oil and Gas Royalty Management Act.

[49 FR 37363, Sept. 21, 1984, as amended at 52 FR 5391, Feb. 20, 1987]

## **Subpart 3162—Requirements for Operating Rights Owners and Operators**

[top](#)

## **§ 3162.1 General requirements.**

[top](#)

(a) The operating rights owner or operator, as appropriate, shall comply with applicable laws and regulations; with the lease terms, Onshore Oil and Gas Orders, NTL's; and with other orders and instructions of the authorized officer. These include, but are not limited to, conducting all operations in a manner which ensures the proper handling, measurement, disposition, and site security of leasehold production; which protects other natural resources and environmental quality; which protects life and property; and which results in maximum ultimate economic recovery of oil and gas with minimum waste and with minimum adverse effect on ultimate recovery of other mineral resources.

(b) The operator shall permit properly identified authorized representatives to enter upon, travel across and inspect lease sites and records normally kept on the lease pertinent thereto without advance notice. Inspections normally will be conducted during those hours when responsible persons are expected to be present at the operation being inspected. Such permission shall include access to secured facilities on such lease sites for the purpose of making any inspection or investigation for determining whether there is compliance with the mineral leasing laws, the regulations in this part, and any applicable orders, notices or directives.

(c) For the purpose of making any inspection or investigation, the Secretary or his authorized representative shall have the same right to enter upon or travel across any lease site as the operator has acquired by purchase, condemnation or otherwise.

[47 FR 47765, Oct. 27, 1982. Redesignated and amended at 48 FR 36583-36586, Aug. 12, 1983; 49 FR 37364, Sept. 21, 1984; 53 FR 17363, May 16, 1988]

## **§ 3162.2 Drilling, producing, and drainage obligations.**

[top](#)

### **§ 3162.2-1 Drilling and producing obligations.**

[top](#)

(a) The operator, at its election, may drill and produce other wells in conformity with any system of well spacing or production allotments affecting the field or area in which the leased lands are situated, and which is authorized and sanctioned by applicable law or by the authorized officer.

(b) After notice in writing, the lessee(s) and operating rights owner(s) shall promptly drill and produce such other wells as the authorized officer may reasonably require in order that the lease may be properly and timely developed and produced in accordance with good economic operating practices.

[66 FR 1892, Jan. 10, 2001. Redesignated at 66 FR 1892, Jan. 10, 2001; 66 FR 24073, May 11, 2001]

### **§ 3162.2-2 What steps may BLM take to avoid uncompensated drainage of Federal or Indian mineral resources?**

[top](#)

If we determine that a well is draining Federal or Indian mineral resources, we may take any of the following actions:

(a) If the mineral resources being drained are in Federal or Indian leases, we may require the lessee to drill and produce all wells that are necessary to protect the lease from drainage, unless the conditions of this part are met. BLM will consider applicable Federal, State, or Tribal rules, regulations, and spacing orders when determining which action to take. Alternatively, we may accept other equivalent protective measures;

(b) If the mineral resources being drained are either unleased (including those which may not be subject to leasing) or in Federal or Indian leases, we may execute agreements with the owners of interests in the producing well under which the United States or the Indian lessor may be compensated for the drainage (with the consent of the Federal or (in consultation with the Indian mineral owner and BIA) Indian lessees, if any);

(c) We may offer for lease any qualifying unleased mineral resources under part 3120 of this chapter or enter into a communitization agreement; or

(d) We may approve a unit or communitization agreement that provides for payment of a royalty on production attributable to unleased mineral resources as provided in §3181.5.

[66 FR 1893, Jan. 10, 2001]

### **§ 3162.2-3 When am I responsible for protecting my Federal or Indian lease from drainage?**



[top](#)

You must protect your Federal or Indian lease from drainage if your lease is being drained of mineral resources by a well:

(a) Producing for the benefit of another mineral owner;

(b) Producing for the benefit of the same mineral owner but with a lower royalty rate; or

(c) Located in a unit or communitization agreement, which due to its Federal or Indian mineral owner's allocation or participation factor, generates less revenue for the United States or the Indian mineral owner for the mineral resources produced from your lease.

[66 FR 1893, Jan. 10, 2001]

### **§ 3162.2-4 What protective action may BLM require the lessee to take to protect the leases from drainage?**



[top](#)

We may require you to:

(a) Drill or modify and produce all wells that are necessary to protect the leased mineral resources from drainage;

(b) Enter into a unitization or communitization agreement with the lease containing the draining well; or

(c) Pay compensatory royalties for drainage that has occurred or is occurring.

[66 FR 1893, Jan. 10, 2001]

### **§ 3162.2-5 Must I take protective action when a protective well would be uneconomic?**



[top](#)

You are not required to take any of the actions listed in §3162.2-4 if you can prove to BLM that when you first knew or had constructive notice of drainage you could not produce a sufficient quantity of oil or gas from a protective well on your lease for a reasonable profit above the cost of drilling, completing, and operating the protective well.

[66 FR 1893, Jan. 10, 2001]

### **§ 3162.2-6 When will I have constructive notice that drainage may be occurring?**



[top](#)

(a) You have constructive notice that drainage may be occurring when well completion or first production reports for the draining well are filed with either BLM, State oil and gas commissions, or regulatory agencies and are publicly available.

(b) If you operate or own any interest in the draining well or lease, you have constructive notice that drainage may be occurring when you complete drill stem, production, pressure analysis, or flow tests of the well.

[66 FR 1893, Jan. 10, 2001]

**§ 3162.2-7 Who is liable for drainage if more than one person holds undivided interests in the record title or operating rights for the same lease?**



[top](#)

(a) If more than one person holds record title interests in a portion of a lease that is subject to drainage, each person is jointly and severally liable for taking any action we may require under this part to protect the lease from drainage, including paying compensatory royalty accruing during the period and for the area in which it holds its record title interest.

(b) Operating rights owners are jointly and severally liable with each other and with all record title holders for drainage affecting the area and horizons in which they hold operating rights during the period they hold operating rights.

[66 FR 1893, Jan. 10, 2001]

**§ 3162.2-8 Does my responsibility for drainage protection end when I assign or transfer my lease interest?**



[top](#)

If you assign your record title interest in a lease or transfer your operating rights, you are not liable for drainage that occurs after the date we approve the assignment or transfer. However, you remain responsible for the payment of compensatory royalties for any drainage that occurred when you held the lease interest.

[66 FR 1893, Jan. 10, 2001]

**§ 3162.2-9 What is my duty to inquire about the potential for drainage and inform BLM of my findings?**



[top](#)

(a) When you first acquire a lease interest, and at all times while you hold the lease interest, you must monitor the drilling of wells in the same or adjacent spacing units and gather sufficient information to determine whether drainage is occurring. This information can be in various forms, including but not limited to, well completion reports, sundry notices, or available production information. As a prudent lessee, it is your responsibility to analyze and evaluate this information and make the necessary calculations to determine:

- (1) The amount of drainage from production of the draining well;
- (2) The amount of mineral resources which will be drained from your Federal or Indian lease during the life of the draining well; and
- (3) Whether a protective well would be economic to drill.

(b) You must notify BLM within 60 days from the date of actual or constructive notice of:

- (1) Which of the actions in §3162.2-4 you will take; or
- (2) The reasons a protective well would be uneconomic.

(c) If you do not have sufficient information to comply with §3162.2-9(b)(1), indicate when you will provide the information.

(d) You must provide BLM with the analysis under paragraph (a) of this section within 60 days after we request it.

[66 FR 1893, Jan. 10, 2001]

**§ 3162.2-10 Will BLM notify me when it determines that drainage is occurring?**



[top](#)

We will send you a demand letter by certified mail, return receipt requested, or personally serve you with notice, if we believe that drainage is occurring. However, your responsibility to take protective action arises when you first knew or had constructive notice of the drainage, even when that date precedes the BLM demand letter.

[66 FR 1894, Jan. 10, 2001]

**§ 3162.2-11 How soon after I know of the likelihood of drainage must I take protective action?**



[top](#)

(a) You must take protective action within a reasonable time after the earlier of:

(1) The date you knew or had constructive notice that the potentially draining well had begun to produce oil or gas; or

(2) The date we issued a demand letter for protective action.

(b) Since the time required to drill and produce a protective well varies according to the location and conditions of the oil and gas reservoir, BLM will determine this on a case-by-case basis. When we determine whether you took protective action within a reasonable time, we will consider several factors including, but not limited to:

(1) Time required to evaluate the characteristics and performance of the draining well;

(2) Rig availability;

(3) Well depth;

(4) Required environmental analysis;

(5) Special lease stipulations which provide limited time frames in which to drill; and

(6) Weather conditions.

(c) If BLM determines that you did not take protection action timely, you will owe compensatory royalty for the period of the delay under §3162.2-12.

[66 FR 1894, Jan. 10, 2001]

**§ 3162.2-12 If I hold an interest in a lease, for what period will the Department assess compensatory royalty against me?**



[top](#)

The Department will assess compensatory royalty beginning on the first day of the month following the earliest reasonable time we determine you should have taken protective action. You must continue to pay compensatory royalty until:

(a) You drill sufficient economic protective wells and remain in continuous production;

(b) We approve a unitization or communitization agreement that includes the mineral resources being drained;

(c) The draining well stops producing; or

(d) You relinquish your interest in the Federal or Indian lease.

[66 FR 1894, Jan. 10, 2001]

**§ 3162.2-13 If I acquire an interest in a lease that is being drained, will the Department assess me for compensatory royalty?**



[top](#)

If you acquire an interest in a Federal or Indian lease through an assignment of record title or transfer of operating rights under this part, you are liable for all drainage obligations accruing on and after the date we approve the assignment or transfer.

[66 FR 1894, Jan. 10, 2001]

**§ 3162.2-14 May I appeal BLM's decision to require drainage protective measures?**



[top](#)

You may appeal any BLM decision requiring you take drainage protective measures. You may request BLM State Director review under 43 CFR 3165.3 and/or appeal to the Interior Board of Land Appeals under 43 CFR part 4 and subpart 1840.

[66 FR 1894, Jan. 10, 2001]

**§ 3162.2-15 Who has the burden of proof if I appeal BLM's drainage determination?**



[top](#)

BLM has the burden of establishing a *prima facie* case that drainage is occurring and that you knew of such drainage. Then the burden of proof shifts to you to refute the existence of drainage or to prove there was not sufficient information to put you on notice of the need for drainage protection. You also have the burden of proving that drilling and producing from a protective well would not be economically feasible.

[66 FR 1894, Jan. 10, 2001]

**§ 3162.3 Conduct of operations.**



[top](#)

(a) Whenever a change in operator occurs, the authorized officer shall be notified promptly in writing, and the new operator shall furnish evidence of sufficient bond coverage in accordance with §3106.6 and subpart 3104 of this title.

(b) A contractor on a leasehold shall be considered the agent of the operator for such operations with full responsibility for acting on behalf of the operator for purposes of complying with applicable laws, regulations, the lease terms, NTL's, Onshore Oil and Gas Orders, and other orders and instructions of the authorized officer.

[53 FR 17363, May 16, 1988; 53 FR 31959, Aug. 22, 1988]

**§ 3162.3-1 Drilling applications and plans.**



[top](#)

(a) Each well shall be drilled in conformity with an acceptable well-spacing program at a surveyed well location approved or prescribed by the authorized officer after appropriate environmental and technical reviews (see §3162.5-1 of this title). An acceptable well-spacing program may be either (1) one which conforms with a spacing order or field rule issued by a State Commission or Board and accepted by the authorized officer, or (2) one which is located on a lease committed to a communitized or unitized tract at a location approved by the authorized officer, or (3) any other program established by the authorized officer.

(b) Any well drilled on restricted Indian land shall be subject to the location restrictions specified in the lease and/or Title 25 of the CFR.

(c) The operator shall submit to the authorized officer for approval an Application for Permit to Drill for each well. No drilling operations, nor surface disturbance preliminary thereto, may be commenced prior to the authorized officer's approval of the permit.

(d) The Application for Permit to Drill process shall be initiated at least 30 days before commencement of operations is desired. Prior to approval, the application shall be administratively and technically complete. A complete application consists of Form 3160-3 and the following attachments:

(1) A drilling plan, which may already be on file, containing information required by paragraph (e) of this section and appropriate orders and notices.

(2) A surface use plan of operations containing information required by paragraph (f) of this section and appropriate orders and notices.

(3) Evidence of bond coverage as required by the Department of the Interior regulations, and

(4) Such other information as may be required by applicable orders and notices.

(e) Each drilling plan shall contain the information specified in applicable notices or orders, including a description of the drilling program, the surface and projected completion zone location, pertinent geologic data, expected hazards, and proposed mitigation measures to address such hazards. A drilling plan may be submitted for a single well or for several wells proposed to be drilled to the same zone within a field or area of geological and environmental similarity. A drilling plan may be modified from time to time as circumstances may warrant, with the approval of the authorized officer.

(f) The surface use plan of operations shall contain information specified in applicable orders or notices, including the road and drillpad location, details of pad construction, methods for containment and disposal of waste material, plans for reclamation of the surface, and other pertinent data as the authorized officer may require. A surface use plan of operations may be submitted for a single well or for several wells proposed to be drilled in an area of environmental similarity.

(g) For Federal lands, upon receipt of the Application for Permit to Drill or Notice of Staking, the authorized officer shall post the following information for public inspection at least 30 days before action to approve the Application for Permit to Drill: the company/operator name; the well name/number; the well location described to the nearest quarter-quarter section (40 acres), or similar land description in the case of lands described by metes and bounds, or maps showing the affected lands and the location of all tracts to be leased and of all leases already issued in the general area; and any substantial modifications to the lease terms. Where the inclusion of maps in such posting is not practicable, maps of the affected lands shall be made available to the public for review. This information also shall be provided promptly by the authorized officer to the appropriate office of the Federal surface management agency, for lands the surface of which is not under Bureau jurisdiction, requesting such agency to post the proposed action for public inspection for at least 30 days. The posting shall be in the office of the authorized officer and in the appropriate surface managing agency if other than the Bureau. The posting of an Application for Permit to Drill is for information purposes only and is not an appealable decision.

(h) Upon initiation of the Application for Permit to Drill process, the authorized officer shall consult with the appropriate Federal surface management agency and with other interested parties as appropriate and shall take one of the following actions as soon as practical, but in no event later than 5 working days after the conclusion of the 30-day notice period for Federal lands, or within 30 days from receipt of the application for Indian lands:

(1) Approve the application as submitted or with appropriate modifications or conditions;

(2) Return the application and advise the applicant of the reasons for disapproval; or

(3) Advise the applicant, either in writing or orally with subsequent written confirmation, of the reasons

why final action will be delayed along with the date such final action can be expected.

The surface use plan of operations for National Forest System lands shall be approved by the Secretary of Agriculture or his/her representative prior to approval of the Application for Permit to Drill by the authorized officer. Appeals from the denial of approval of such surface use plan of operations shall be submitted to the Secretary of Agriculture.

(i) Approval of the Application for Permit to Drill does not warrant or certify that the applicant holds legal or equitable title to the subject lease(s) which would entitle the applicant to conduct drilling operations.

[47 FR 47765, Oct. 27, 1982. Redesignated and amended at 48 FR 36583–36586, Aug. 12, 1983, further amended at 52 FR 5391, Feb. 20, 1987; 53 FR 17363, May 16, 1988; 53 FR 22846, June 17, 1988; 53 FR 31958, Aug. 22, 1988]

### **§ 3162.3-2 Subsequent well operations.**



[top](#)

(a) A proposal for further well operations shall be submitted by the operator on Form 3160–5 for approval by the authorized officer prior to commencing operations to redrill, deepen, perform casing repairs, plug-back, alter casing, perform nonroutine fracturing jobs, recomplete in a different interval, perform water shut off, commingling production between intervals and/or conversion to injection. If there is additional surface disturbance, the proposal shall include a surface use plan of operations. A subsequent report on these operations also will be filed on Form 3160–5. The authorized officer may prescribe that each proposal contain all or a portion of the information set forth in §3162.3–1 of this title.

(b) Unless additional surface disturbance is involved and if the operations conform to the standard of prudent operating practice, prior approval is not required for routine fracturing or acidizing jobs, or recompletion in the same interval; however, a subsequent report on these operations must be filed on Form 3160–5.

(c) No prior approval or a subsequent report is required for well cleanout work, routine well maintenance, or bottom hole pressure surveys.

[47 FR 47765, Oct. 27, 1982. Redesignated and amended at 48 FR 36583–36586, Aug. 12, 1983, further amended at 52 FR 5391, Feb. 20, 1987; 53 FR 17363, May 16, 1988; 53 FR 22847, June 17, 1988]

### **§ 3162.3-3 Other lease operations.**



[top](#)

Prior to commencing any operation on the leasehold which will result in additional surface disturbance, other than those authorized under §3162.3–1 or §3162.3–2 of this title, the operator shall submit a proposal on Form 3160–5 to the authorized officer for approval. The proposal shall include a surface use plan of operations.

[47 FR 47765, Oct. 27, 1982. Redesignated and amended at 48 FR 36583–36586, Aug. 12, 1983, and amended at 52 FR 5391, Feb. 20, 1987; 53 FR 17363, May 16, 1988; 53 FR 22847, June 17, 1988]

### **§ 3162.3-4 Well abandonment.**



[top](#)

(a) The operator shall promptly plug and abandon, in accordance with a plan first approved in writing or prescribed by the authorized officer, each newly completed or recompleted well in which oil or gas is not encountered in paying quantities or which, after being completed as a producing well, is demonstrated to the satisfaction of the authorized officer to be no longer capable of producing oil or gas in paying quantities, unless the authorized officer shall approve the use of the well as a service well for injection to recover additional oil or gas or for subsurface disposal of produced water. In the case of a newly drilled or recompleted well, the approval to abandon may be written or oral with written confirmation.

(b) Completion of a well as plugged and abandoned may also include conditioning the well as water supply source for lease operations or for use by the surface owner or appropriate Government Agency,

when authorized by the authorized officer. All costs over and above the normal plugging and abandonment expense will be paid by the party accepting the water well.

(c) No well may be temporarily abandoned for more than 30 days without the prior approval of the authorized officer. The authorized officer may authorize a delay in the permanent abandonment of a well for a period of 12 months. When justified by the operator, the authorized officer may authorize additional delays, no one of which may exceed an additional 12 months. Upon the removal of drilling or producing equipment from the site of a well which is to be permanently abandoned, the surface of the lands disturbed in connection with the conduct of operations shall be reclaimed in accordance with a plan first approved or prescribed by the authorized officer.

[47 FR 47765, Oct. 27, 1982. Redesignated and amended at 48 FR 36583–36586, Aug. 12, 1983, further amended at 53 FR 17363, May 16, 1988; 53 FR 22847, June 17, 1988]

#### § 3162.4 Records and reports.



[top](#)

##### § 3162.4-1 Well records and reports.



[top](#)

(a) The operator shall keep accurate and complete records with respect to all lease operations including, but not limited to, production facilities and equipment, drilling, producing, redrilling, deepening, repairing, plugging back, and abandonment operations, and other matters pertaining to operations. With respect to production facilities and equipment, the record shall include schematic diagrams as required by applicable orders and notices.

(b) Standard forms for providing basic data are listed in Note 1 at the beginning of this title. As noted on Form 3160–4, two copies of all electric and other logs run on the well must be submitted to the authorized officer. Upon request, the operator shall transmit to the authorized officer copies of such other records maintained in compliance with paragraph (a) of this section.

(c) Not later than the 5th business day after any well begins production on which royalty is due anywhere on a lease site or allocated to a lease site, or resumes production in the case of a well which has been off production for more than 90 days, the operator shall notify the authorized officer by letter or sundry notice, Form 3160–5, or orally to be followed by a letter or sundry notice, of the date on which such production has begun or resumed.

(d) All records and reports required by this section shall be maintained for 6 years from the date they were generated. In addition, if the Secretary, or his/her designee notifies the recordholder that the Department of the Interior has initiated or is participating in an audit or investigation involving such records, the records shall be maintained until the Secretary, or his/her designee, releases the recordholder from the obligation to maintain such records.

[47 FR 47765, Oct. 27, 1982. Redesignated and amended at 48 FR 36583–36586, Aug. 12, 1983; 49 FR 37364, Sept. 21, 1984; 52 FR 5391, Feb. 20, 1987; 53 FR 17363, May 16, 1988]

##### § 3162.4-2 Samples, tests, and surveys.



[top](#)

(a) During the drilling and completion of a well, the operator shall, when required by the authorized officer, conduct tests, run logs, and make other surveys reasonably necessary to determine the presence, quantity, and quality of oil, gas, other minerals, or the presence or quality of water; to determine the amount and/or direction of deviation of any well from the vertical; and to determine the relevant characteristics of the oil and gas reservoirs penetrated.

(b) After the well has been completed, the operator shall conduct periodic well tests which will demonstrate the quantity and quality of oil and gas and water. The method and frequency of such well tests will be specified in appropriate notices and orders. When needed, the operator shall conduct reasonable tests which will demonstrate the mechanical integrity of the downhole equipment.

(c) Results of samples, tests, and surveys approved or prescribed under this section shall be provided to

the authorized officer without cost to the lessor.

[47 FR 47765, Oct. 27, 1982. Redesignated and amended at 48 FR 36583–36586, Aug. 12, 1983, further amended at 53 FR 17363, May 16, 1988]

### § 3162.4-3 Monthly report of operations (Form 3160–6).



[top](#)

The operator shall report production data to BLM in accordance with the requirements of this section until required to begin reporting to MMS pursuant to 30 CFR 216.50. When reporting production data to BLM in accordance with the requirements of this section, the operator shall either use Form BLM 3160–6 or Form MMS–3160. A separate report of operations for each lease shall be made on Form 3160–6 for each calendar month, beginning with the month in which drilling operations are initiated, and shall be filed with the authorized officer on or before the 10th day of the second month following the operation month, unless an extension of time for the filing of such report is granted by the authorized officer. The report on this form shall disclose accurately all operations conducted on each well during each month, the status of operations on the last day of the month, and a general summary of the status of operations on the leased lands, and the report shall be submitted each month until the lease is terminated or until omission of the report is authorized by the authorized officer. It is particularly necessary that the report shall show for each calendar month:

- (a) The lease be identified by inserting the name of the United States land office and the serial number, or in the case of Indian land, the lease number and lessor's name, in the space provided in the upper right corner;
- (b) Each well be listed separately by number, its location be given by 40-acre subdivision (1/41/4sec. or lot), section number, township, range, and meridian;
- (c) The number of days each well produced, whether oil or gas, and the number of days each input well was in operation be stated;
- (d) The quantity of oil, gas and water produced, the total amount of gasoline, and other lease products recovered, and other required information. When oil and gas, or oil, gas and gasoline, or other hydrocarbons are concurrently produced from the same lease, separate reports on this form should be submitted for oil and for gas and gasoline, unless otherwise authorized or directed by the authorized officer.
- (e) The depth of each active or suspended well, and the name, character, and depth of each formation drilled during the month, the date each such depth was reached, the date and reason for every shut-down, the names and depths of important formation changes and contents of formations, the amount and size of any casing run since last report, the dates and results of any tests such as production, water shut-off, or gasoline content, and any other noteworthy information on operations not specifically provided for in the form.
- (f) The footnote shall be completely filled out as required by the authorized officer. If no runs or sales were made during the calendar month, the report shall so state.

[47 FR 47765, Oct. 27, 1982. Redesignated and amended at 48 FR 36583–36586, Aug. 12, 1983; 52 FR 5391, Feb. 20, 1987; 53 FR 16413, May 9, 1988]

### § 3162.5 Environment and safety.



[top](#)

#### § 3162.5-1 Environmental obligations.



[top](#)

- (a) The operator shall conduct operations in a manner which protects the mineral resources, other natural resources, and environmental quality. In that respect, the operator shall comply with the pertinent orders of the authorized officer and other standards and procedures as set forth in the applicable laws, regulations, lease terms and conditions, and the approved drilling plan or subsequent operations plan. Before approving any Application for Permit to Drill submitted pursuant to §3162.3–1 of this title, or other

plan requiring environmental review, the authorized officer shall prepare an environmental record of review or an environmental assessment, as appropriate. These environmental documents will be used in determining whether or not an environmental impact statement is required and in determining any appropriate terms and conditions of approval of the submitted plan.

(b) The operator shall exercise due care and diligence to assure that leasehold operations do not result in undue damage to surface or subsurface resources or surface improvements. All produced water must be disposed of by injection into the subsurface, by approved pits, or by other methods which have been approved by the authorized officer. Upon the conclusion of operations, the operator shall reclaim the disturbed surface in a manner approved or reasonably prescribed by the authorized officer.

(c) All spills or leakages of oil, gas, produced water, toxic liquids, or waste materials, blowouts, fires, personal injuries, and fatalities shall be reported by the operator in accordance with these regulations and as prescribed in applicable order or notices. The operator shall exercise due diligence in taking necessary measures, subject to approval by the authorized officer, to control and remove pollutants and to extinguish fires. An operator's compliance with the requirements of the regulations in this part shall not relieve the operator of the obligation to comply with other applicable laws and regulations.

(d) When reasonably required by the authorized officer, a contingency plan shall be submitted describing procedures to be implemented to protect life, property, and the environment.

(e) The operator's liability for damages to third parties shall be governed by applicable law.

[47 FR 47765, Oct. 27, 1982. Redesignated and amended at 48 FR 36583–36586, Aug. 12, 1983, further amended at 53 FR 17363, May 16, 1988; 53 FR 22847, June 17, 1988]

#### § 3162.5-2 Control of wells.



[top](#)

(a) *Drilling wells.* The operator shall take all necessary precautions to keep each well under control at all times, and shall utilize and maintain materials and equipment necessary to insure the safety of operating conditions and procedures.

(b) *Vertical drilling.* The operator shall conduct drilling operations in a manner so that the completed well does not deviate significantly from the vertical without the prior written approval of the authorized officer. Significant deviation means a projected deviation of the well bore from the vertical of 10° or more, or a projected bottom hole location which could be less than 200 feet from the spacing unit or lease boundary. Any well which deviates more than 10° from the vertical or could result in a bottom hole location less than 200 feet from the spacing unit or lease boundary without prior written approval must be promptly reported to the authorized officer. In these cases, a directional survey is required.

(c) *High pressure or loss of circulation.* The operator shall take immediate steps and utilize necessary resources to maintain or restore control of any well in which the pressure equilibrium has become unbalanced.

(d) *Protection of fresh water and other minerals.* The operator shall isolate freshwater-bearing and other usable water containing 5,000 ppm or less of dissolved solids and other mineral-bearing formations and protect them from contamination. Tests and surveys of the effectiveness of such measures shall be conducted by the operator using procedures and practices approved or prescribed by the authorized officer.

[47 FR 47765, Oct. 27, 1982. Redesignated and amended at 48 FR 36583–36586, Aug. 12, 1983, further amended at 53 FR 17363, May 16, 1988]

#### § 3162.5-3 Safety precautions.



[top](#)

The operator shall perform operations and maintain equipment in a safe and workmanlike manner. The operator shall take all precautions necessary to provide adequate protection for the health and safety of life and the protection of property. Compliance with health and safety requirements prescribed by the authorized officer shall not relieve the operator of the responsibility for compliance with other pertinent health and safety requirements under applicable laws or regulations.

[47 FR 47765, Oct. 27, 1982. Redesignated and amended at 48 FR 36583-36586, Aug. 12, 1983, further amended at 53 FR 17363, May 16, 1988]

#### **§ 3162.6 Well and facility identification.**



(a) Every well within a Federal or Indian lease or supervised agreement shall have a well identification sign. All signs shall be maintained in a legible condition.

(b) For wells located on Federal and Indian lands, the operator shall properly identify, by a sign in a conspicuous place, each well, other than those permanently abandoned. The well sign shall include the well number, the name of the operator, the lease serial number, the surveyed location (the quarter-quarter section, section, township and range or other authorized survey designation acceptable to the authorized officer; such as metes and bounds). When approved by the authorized officer, individual well signs may display only a unique well name and number. When specifically requested by the authorized officer, the sign shall include the unit or communitization name or number. The authorized officer may also require the sign to include the name of the Indian allottee lessor(s) preceding the lease serial number. In all cases, individual well signs in place on the effective date of this rulemaking which do not have the unit or communitization agreement number or do not have quarter-quarter identification will satisfy these requirements until such time as the sign is replaced. All new signs shall have identification as above, including quarter-quarter section.

(c) All facilities at which Federal or Indian oil is stored shall be clearly identified with a sign that contains the name of the operator, the lease serial number or communitization or unit agreement identification number, as appropriate, and in public land states, the quarter-quarter section, township, and range. On Indian leases, the sign also shall include the name of the appropriate Tribe and whether the lease is tribal or allotted. For situations of 1 tank battery servicing 1 well in the same location, the requirements of this paragraph and paragraph (b) of this section may be met by 1 sign as long as it includes the information required by both paragraphs. In addition, each storage tank shall be clearly identified by a unique number. All identification shall be maintained in legible condition and shall be clearly apparent to any person at or approaching the sales or transportation point. With regard to the quarter-quarter designation and the unique tank number, any such designation established by state law or regulation shall satisfy this requirement.

(d) All abandoned wells shall be marked with a permanent monument containing the information in paragraph (b) of this section. The requirement for a permanent monument may be waived in writing by the authorized officer.

[52 FR 5391, Feb. 20, 1987, as amended at 53 FR 17363, May 16, 1988]

#### **§ 3162.7 Measurement, disposition, and protection of production.**



##### **§ 3162.7-1 Disposition of production.**



(a) The operator shall put into marketable condition, if economically feasible, all oil, other hydrocarbons, gas, and sulphur produced from the leased land.

(b) Where oil accumulates in a pit, such oil must either be (1) recirculated through the regular treating system and returned to the stock tanks for sale, or (2) pumped into a stock tank without treatment and measured for sale in the same manner as from any sales tank in accordance with applicable orders and notices. In the absence of prior approval from the authorized officer, no oil should go to a pit except in an emergency. Each such occurrence must be reported to the authorized officer and the oil promptly recovered in accordance with applicable orders and notices.

(c)(1) Any person engaged in transporting by motor vehicle any oil from any lease site, or allocated to any such lease site, shall carry on his/her person, in his/her vehicle, or in his/her immediate control, documentation showing at a minimum; the amount, origin, and intended first purchaser of the oil.

(2) Any person engaged in transporting any oil or gas by pipeline from any lease site, or allocated to any lease site, shall maintain documentation showing, at a minimum, the amount, origin, and intended first

purchaser of such oil or gas.

(3) On any lease site, any authorized representative who is properly identified may stop and inspect any motor vehicle that he/she has probable cause to believe is carrying oil from any such lease site, or allocated to such lease site, to determine whether the driver possesses proper documentation for the load of oil.

(4) Any authorized representative who is properly identified and who is accompanied by an appropriate law enforcement officer, or an appropriate law enforcement officer alone, may stop and inspect any motor vehicle which is not on a lease site if he/she has probable cause to believe the vehicle is carrying oil from a lease site, or allocated to a lease site, to determine whether the driver possesses proper documentation for the load of oil.

(d) The operator shall conduct operations in such a manner as to prevent avoidable loss of oil and gas. A operator shall be liable for royalty payments on oil or gas lost or wasted from a lease site, or allocated to a lease site, when such loss or waste is due to negligence on the part of the operator of such lease, or due to the failure of the operator to comply with any regulation, order or citation issued pursuant to this part.

(e) When requested by the authorized officer, the operator shall furnish storage for royalty oil, on the leasehold or at a mutually agreed upon delivery point off the leased land without cost to the lessor, for 30 days following the end of the calendar month in which the royalty accrued.

(f) Any records generated under this section shall be maintained for 6 years from the date they were generated or, if notified by the Secretary, or his designee, that such records are involved in an audit or investigation, the records shall be maintained until the recordholder is released by the Secretary from the obligation to maintain them.

[47 FR 47765, Oct. 27, 1982. Redesignated and amended at 48 FR 36583-36586, Aug. 12, 1983; 49 FR 37364, Sept. 21, 1984; 53 FR 17363, May 16, 1988]

#### **§ 3162.7-2 Measurement of oil.**



All oil production shall be measured on the lease by tank gauging, positive displacement metering system, or other methods acceptable to the authorized officer, pursuant to methods and procedures prescribed in applicable orders and notices. Where production cannot be measured due to spillage or leakage, the amount of production shall be determined in accordance with the methods and procedures approved or prescribed by the authorized officer. Off-lease storage or measurement, or commingling with production from other sources prior to measurement, may be approved by the authorized officer.

[47 FR 47765, Oct. 27, 1982. Redesignated and amended at 48 FR 36583-36586, Aug. 12, 1983; 49 FR 37364, Sept. 21, 1984; 52 FR 5392, Feb. 20, 1987]

#### **§ 3162.7-3 Measurement of gas.**



All gas production shall be measured by orifice meters or other methods acceptable to the authorized officer on the lease pursuant to methods and procedures prescribed in applicable orders and notices. The measurement of the volume of all gas produced shall be adjusted by computation to the standard pressure and temperature of 14.73 psia and 60° F unless otherwise prescribed by the authorized officer, regardless of the pressure and temperature at which the gas is actually measured. Gas lost without measurement by meter shall be estimated in accordance with methods prescribed in applicable orders and notices. Off-lease measurement or commingling with production from other sources prior to measurement may be approved by the authorized officer.

[47 FR 47765, Oct. 27, 1982. Redesignated and amended at 48 FR 36583-36586, Aug. 12, 1983; 49 FR 37364, Sept. 21, 1984; 52 FR 5392, Feb. 20, 1987]

#### **§ 3162.7-4 Royalty rates on oil; sliding and step-scale leases (public land only).**



Sliding- and step-scale royalties are based on the average daily production per well. The authorized officer shall specify which wells on a leasehold are commercially productive, including in that category all wells, whether produced or not, for which the annual value of permissible production would be greater than the estimated reasonable annual lifting cost, but only wells that yield a commercial volume of production during at least part of the month shall be considered in ascertaining the average daily production per well. The average daily production per well for a lease is computed on the basis of a 28-, 29-, 30-, or 31-day month (as the case may be), the number of wells on the leasehold counted as producing, and the gross production from the leasehold. The authorized officer will determine which commercially productive wells shall be considered each month as producing wells for the purpose of computing royalty in accordance with the following rules, and in the authorized officer's discretion may count as producing any commercially productive well shut in for conservation purposes.

(a) For a previously producing leasehold, count as producing for every day of the month each previously producing well that produced 15 days or more during the month, and disregard wells that produced less than 15 days during the month.

(b) Wells approved by the authorized officer as input wells shall be counted as producing wells for the entire month if so used 15 days or more during the month and shall be disregarded if so used less than 15 days during the month.

(c) When the initial production of a leasehold is made during the calendar month, compute royalty on the basis of producing well days.

(d) When a new well is completed for production on a previously producing leasehold and produces for 10 days or more during the calendar month in which it is brought in, count such new wells as producing every day of the month in arriving at the number of producing well days. Do not count any new well that produces for less than 10 days during the calendar month.

(e) Consider "head wells" that make their best production by intermittent pumping or flowing as producing every day of the month, provided they are regularly operated in this manner with approval of the authorized officer.

(f) For previously producing leaseholds on which no wells produced for 15 days or more, compute royalty on the basis of actual producing well days.

(g) For previously producing leaseholds on which no wells were productive during the calendar month but from which oil was shipped, compute royalty at the same royalty percentage as that of the last preceding calendar month in which production and shipments were normal.

(h) Rules for special cases not subject to definition, such as those arising from averaging the production from two distinct sands or horizons when the production of one sand or horizon is relatively insignificant compared to that of the other, shall be made by the authorized officer as need arises.

(i)(1) In the following summary of operations on a typical leasehold for the month of June, the wells considered for the purpose of computing royalty on the entire production of the property for the months are indicated.

Well No. and record	Count (marked X)
1. Produced full time for 30 days	X
2. Produced for 26 days; down 4 days for repairs	X
3. Produced for 28 days; down June 5, 12 hours, rods; June 14, 6 hours, engine down; June 26, 24 hours, pulling rods and tubing	X
4. Produced for 12 days; down June 13 to 30	
5. Produced for 8 hours every day (head well)	X
6. Idle producer (not operated)	
7. New well, completed June 17; produced for 14 days	X
8. New well, completed June 22; produced for 9 days	

(2) In this example, there are eight wells on the leasehold, but wells No. 4, 6, and 8 are not counted in computing royalties. Wells No. 1, 2, 3, 5, and 7 are counted as producing for 30 days. The average

production per well per day is determined by dividing the total production of the leasehold for the month (including the oil produced by wells 4 and 8) by 5 (the number of wells counted as producing), and dividing the quotient thus obtained by the number of days in the month.

[53 FR 1226, Jan. 15, 1988, as amended at 53 FR 17364, May 16, 1988]

#### **§ 3162.7-5 Site security on Federal and Indian (except Osage) oil and gas leases.**



(a) *Definitions. Appropriate valves.* Those valves in a particular piping system, i.e., fill lines, equalizer or overflow lines, sales lines, circulating lines, and drain lines that shall be sealed during a given operation.

*Effectively sealed.* The placement of a seal in such a manner that the position of the sealed valve may not be altered without the seal being destroyed.

*Production phase.* That period of time or mode of operation during which crude oil is delivered directly to or through production vessels to the storage facilities and includes all operations at the facility other than those defined by the sales phase.

*Sales phase.* That period of time or mode of operation during which crude oil is removed from the storage facilities for sales, transportation or other purposes.

*Seal.* A device, uniquely numbered, which completely secures a valve.

(b) *Minimum Standards.* Each operator of a Federal or Indian lease shall comply with the following minimum standards to assist in providing accountability of oil or gas production:

(1) All lines entering or leaving oil storage tanks shall have valves capable of being effectively sealed during the production and sales operations unless otherwise modified by other subparagraphs of this paragraph, and any equipment needed for effective sealing, excluding the seals, shall be located at the site. For a minimum of 6 years the operator shall maintain a record of seal numbers used and shall document on which valves or connections they were used as well as when they were installed and removed. The site facility diagram(s) shall show which valves will be sealed in which position during both the production and sales phases of operation.

(2) Each Lease Automatic Custody Transfer (LACT) system shall employ meters that have non-resettable totalizers. There shall be no by-pass piping around the LACT. All components of the LACT that are used for volume or quality determinations of the oil shall be effectively sealed. For systems where production may only be removed through the LACT, no sales or equalizer valves need be sealed. However, any valves which may allow access for removal of oil before measurement through the LACT shall be effectively sealed.

(3) There shall be no by-pass piping around gas meters. Equipment which permits changing the orifice plate without bleeding the pressure off the gas meter run is not considered a by-pass.

(4) For oil measured and sold by hand gauging, all appropriate valves shall be sealed during the production or sales phase, as applicable.

(5) Circulating lines having valves which may allow access to remove oil from storage and sales facilities to any other source except through the treating equipment back to storage shall be effectively sealed as near the storage tank as possible.

(6) The operator, with reasonable frequency, shall inspect all leases to determine production volumes and that the minimum site security standards are being met. The operator shall retain records of such inspections and measurements for 6 years from generation. Such records and measurements shall be available to any authorized officer or authorized representative upon request.

(7) Any person removing oil from a facility by motor vehicle shall possess the identification documentation required by applicable NTL's or onshore Orders while the oil is removed and transported.

(8) Theft or mishandling of oil from a Federal or Indian lease shall be reported to the authorized officer as soon as discovered, but not later than the next business day. Said report shall include an estimate of the volume of oil involved. Operators also are expected to report such thefts promptly to local law enforcement agencies and internal company security.

(9) Any operator may request the authorized officer to approve a variance from any of the minimum standards prescribed by this section. The variance request shall be submitted in writing to the authorized officer who may consider such factors as regional oil field facility characteristics and fenced, guarded sites. The authorized officer may approve a variance if the proposed alternative will ensure measures equal to or in excess of the minimum standards provided in paragraph (b) of this section will be put in place to detect or prevent internal and external theft, and will result in proper production accountability.

(c) *Site security plans.* (1) Site security plans, which include the operator's plan for complying with the minimum standards enumerated in paragraph (b) of this section for ensuring accountability of oil/condensate production are required for all facilities and such facilities shall be maintained in compliance with the plan. For new facilities, notice shall be given that it is subject to a specific existing plan, or a notice of a new plan shall be submitted, no later than 60 days after completion of construction or first production or following the inclusion of a well on committed non-Federal lands into a federally supervised unit or communitization agreement, whichever occurs first, and on that date the facilities shall be in compliance with the plan. At the operator's option, a single plan may include all of the operator's leases, unit and communitized areas, within a single BLM district, provided the plan clearly identifies each lease, unit, or communitized area included within the scope of the plan and the extent to which the plan is applicable to each lease, unit, or communitized area so identified.

(2) The operator shall retain the plan but shall notify the authorized officer of its completion and which leases, unit and communitized areas are involved. Such notification is due at the time the plan is completed as required by paragraph (c)(1) of this section. Such notification shall include the location and normal business hours of the office where the plan will be maintained. Upon request, all plans shall be made available to the authorized officer.

(3) The plan shall include the frequency and method of the operator's inspection and production volume recordation. The authorized officer may, upon examination, require adjustment of the method or frequency of inspection.

(d) *Site facility diagrams.* (1) Facility diagrams are required for all facilities which are used in storing oil/condensate produced from, or allocated to, Federal or Indian lands. Facility diagrams shall be filed within 60 days after new measurement facilities are installed or existing facilities are modified or following the inclusion of the facility into a federally supervised unit or communitization agreement.

(2) No format is prescribed for facility diagrams. They are to be prepared on 8 1/2 inch x 11 inch paper, if possible, and be legible and comprehensible to a person with ordinary working knowledge of oil field operations and equipment. The diagram need not be drawn to scale.

(3) A site facility diagram shall accurately reflect the actual conditions at the site and shall, commencing with the header if applicable, clearly identify the vessels, piping, metering system, and pits, if any, which apply to the handling and disposal of oil, gas and water. The diagram shall indicate which valves shall be sealed and in what position during the production or sales phase. The diagram shall clearly identify the lease on which the facility is located and the site security plan to which it is subject, along with the location of the plan.

[47 FR 47765, Oct. 27, 1982. Redesignated at 48 FR 36583-36586, Aug. 12, 1983, and amended at 52 FR 5392, Feb. 20, 1987. Redesignated at 53 FR 1218, Jan. 15, 1988; 53 FR 24688, June 30, 1988]

## Subpart 3163—Noncompliance, Assessments, and Penalties



[top](#)

### § 3163.1 Remedies for acts of noncompliance.



[top](#)

(a) Whenever an operating rights owner or operator fails or refuses to comply with the regulations in this part, the terms of any lease or permit, or the requirements of any notice or order, the authorized officer shall notify the operating rights owner or operator, as appropriate, in writing of the violation or default. Such notice shall also set forth a reasonable abatement period:

(1) If the violation or default is not corrected within the time allowed, the authorized officer may subject the operating rights owner or operator, as appropriate, to an assessment of not more than \$500 per day for each day nonabatement continues where the violation or default is deemed a major violation;

(2) Where noncompliance involves a minor violation, the authorized officer may subject the operating

rights owner or operator, as appropriate, to an assessment of \$250 for failure to abate the violation or correct the default within the time allowed;

(3) When necessary for compliance, or where operations have been commenced without approval, or where continued operations could result in immediate, substantial, and adverse impacts on public health and safety, the environment, production accountability, or royalty income, the authorized officer may shut down operations. Immediate shut-in action may be taken where operations are initiated and conducted without prior approval, or where continued operations could result in immediate, substantial, and adverse impacts on public health and safety, the environment, production accountability, or royalty income. Shut-in actions for other situations may be taken only after due notice, in writing, has been given;

(4) When necessary for compliance, the authorized officer may enter upon a lease and perform, or have performed, at the sole risk and expense of the operator, operations that the operator fails to perform when directed in writing by the authorized officer. Appropriate charges shall include the actual cost of performance, plus an additional 25 percent of such amount to compensate the United States for administrative costs. The operator shall be provided with a reasonable period of time either to take corrective action or to show why the lease should not be entered;

(5) Continued noncompliance may subject the lease to cancellation and forfeiture under the bond. The operator shall be provided with a reasonable period of time either to take corrective action or to show why the lease should not be recommended for cancellation;

(6) Where actual loss or damage has occurred as a result of the operator's noncompliance, the actual amount of such loss or damage shall be charged to the operator.

(b) Certain instances of noncompliance are violations of such a serious nature as to warrant the imposition of immediate assessments upon discovery. Upon discovery the following violations shall result in immediate assessments, which may be retroactive, in the following specified amounts per violation:

(1) For failure to install blowout preventer or other equivalent well control equipment, as required by the approved drilling plan, \$500 per day for each day that the violation existed, including days the violation existed prior to discovery, not to exceed \$5,000;

(2) For drilling without approval or for causing surface disturbance on Federal or Indian surface preliminary to drilling without approval, \$500 per day for each day that the violation existed, including days the violation existed prior to discovery, not to exceed \$5,000;

(3) For failure to obtain approval of a plan for well abandonment prior to commencement of such operations, \$500.

(c) Assessments under paragraph (a)(1) of this section shall not exceed \$1,000 per day, per operating rights owner or operator, per lease. Assessments under paragraph (a)(2) of this section shall not exceed a total of \$500 per operating rights owner or operator, per lease, per inspection.

(d) Continued noncompliance shall subject the operating rights owner or operator, as appropriate, to penalties described in §3163.2 of this title.

(e) On a case-by-case basis, the State Director may compromise or reduce assessments under this section. In compromising or reducing the amount of the assessment, the State Director shall state in the record the reasons for such determination.

[52 FR 5393, Feb. 20, 1987; 52 FR 10225, Mar. 31, 1987, as amended at 53 FR 17364, May 16, 1988; 53 FR 22847, June 17, 1988]

### § 3163.2 Civil penalties.



top

(a) Whenever an operating rights owner or operator, as appropriate, fails or refuses to comply with any applicable requirements of the Federal Oil and Gas Royalty Management Act, any mineral leasing law, any regulation thereunder, or the terms of any lease or permit issued thereunder, the authorized officer shall notify the operating rights owner or operator, as appropriate, in writing of the violation, unless the violation was discovered and reported to the authorized officer by the liable person or the notice was previously issued under §3163.1 of this title. If the violation is not corrected within 20 days of such notice

or report, or such longer time as the authorized officer may agree to in writing, the operating rights owner or operator, as appropriate, shall be liable for a civil penalty of up to \$500 per violation for each day such violation continues, dating from the date of such notice or report. Any amount imposed and paid as assessments under the provisions of §3163.1(a)(1) of this title shall be deducted from penalties under this section.

(b) If the violation specified in paragraph (a) of this section is not corrected within 40 days of such notice or report, or a longer period as the authorized officer may agree to in writing, the operating rights owner or operator, as appropriate, shall be liable for a civil penalty of up to \$5,000 per violation for each day the violation continues, not to exceed a maximum of 60 days, dating from the date of such notice or report. Any amount imposed and paid as assessments under the provisions of §3163.1(a)(1) of this title shall be deducted from penalties under this section.

(c) In the event the authorized officer agrees to an abatement period of more than 20 days, the date of notice shall be deemed to be 20 days prior to the end of such longer abatement period for the purpose of civil penalty calculation.

(d) Whenever a transporter fails to permit inspection for proper documentation by any authorized representative, as provided in §3162.7-1(c) of this title, the transporter shall be liable for a civil penalty of up to \$500 per day for the violation, not to exceed a maximum of 20 days, dating from the date of notice of the failure to permit inspection and continuing until the proper documentation is provided.

(e) Any person shall be liable for a civil penalty of up to \$10,000 per violation for each day such violation continues, not to exceed a maximum of 20 days if he/she:

(1) Fails or refuses to permit lawful entry or inspection authorized by §3162.1(b) of this title; or

(2) Knowingly or willfully fails to notify the authorized officer by letter or Sundry Notice, Form 3160-5 or orally to be followed by a letter or Sundry Notice, not later than the 5th business day after any well begins production on which royalty is due, or resumes production in the case of a well which has been off of production for more than 90 days, from a well located on a lease site, or allocated to a lease site, of the date on which such production began or resumed.

(f) Any person shall be liable for a civil penalty of up to \$25,000 per violation for each day such violation continues, not to exceed a maximum of 20 days if he/she:

(1) Knowingly or willfully prepares, maintains or submits false, inaccurate or misleading reports, notices, affidavits, records, data or other written information required by this part; or

(2) Knowingly or willfully takes or removes, transports, uses or diverts any oil or gas from any Federal or Indian lease site without having valid legal authority to do so; or

(3) Purchases, accepts, sells, transports or conveys to another any oil or gas knowing or having reason to know that such oil or gas was stolen or unlawfully removed or diverted from a Federal or Indian lease site.

(g) Determinations of Penalty Amounts for this section are as follows:

(1) For major violations, all initial proposed penalties shall be at the maximum rate provided in paragraphs (a), (b), and (d) through (f) of this section, i.e., in paragraph (a) of this section, the initial proposed penalty for a major violation shall be at the rate of \$500 per day through the 40th day of a noncompliance beginning after service of notice, and in paragraph (b) of this section, \$5,000 per day for each day the violation remains uncorrected after the date of notice or report of the violation. Such penalties shall not exceed a rate of \$1,000 per day, per operating rights owner or operator, per lease under paragraph (a) of this section or \$10,000 per day, per operating rights owner or operator, per lease under paragraph (b) of this section. For paragraphs (d) through (f) of this section, the rate shall be \$500, \$10,000, and \$25,000, respectively.

(2) For minor violations, no penalty under paragraph (a) of this section shall be assessed unless:

(i) The operating rights owner or operator, as appropriate, has been notified of the violation in writing and did not correct the violation within the time allowed; and

(ii) The operating rights owner or operator, as appropriate, has been assessed \$250 under §3163.1 of this title and a second notice has been issued giving an abatement period of not less than 20 days; and

(iii) The noncompliance was not abated within the time allowed by the second notice. The initial

proposed penalty for a minor violation under paragraph (a) of this section shall be at the rate of \$50 per day beginning with the date of the second notice. Under paragraph (b) of this section, the penalty shall be at a daily rate of \$500. Such penalties shall not exceed a rate of \$100 per day, per operating rights owner or operator, per lease under paragraph (a) of this section, of \$1,000 per day, per operating rights owner or operator, per lease under paragraph (b) of this section.

(h) On a case-by-case basis, the Secretary may compromise or reduce civil penalties under this section. In compromising or reducing the amount of a civil penalty, the Secretary shall state on the record the reasons for such determination.

(i) Civil penalties provided by this section shall be supplemental to, and not in derogation of, any other penalties or assessments for noncompliance in any other provision of law, except as provided in paragraphs (a) and (b) of this section.

(j) If the violation continues beyond the 60-day maximum specified in paragraph (b) of this section or beyond the 20 day maximum specified in paragraphs (e) and (f) of this section, lease cancellation proceedings shall be initiated under either Title 43 or Title 25 of the Code of Federal Regulations.

(k) If the violation continues beyond the 20-day maximum specified in paragraph (d) of this section, the authorized officer shall revoke the transporter's authority to remove crude oil or other liquid hydrocarbons from any Federal or Indian lease under the authority of that authorized officer or to remove any crude oil or liquid hydrocarbons allocation to such lease site. This revocation of the transporter's authority shall continue until compliance is achieved and related penalty paid.

[52 FR 5393, Feb. 20, 1987; 52 FR 10225, Mar. 31, 1987, as amended at 53 FR 17364, May 16, 1988]

### **§ 3163.3 Criminal penalties.**



[top](#)

Any person who commits an act for which a civil penalty is provided in §3163.2(f) shall, upon conviction, be punished by a fine of not more than \$50,000, or by imprisonment for not more than 2 years, or both.

[70 FR 75954, Dec. 22, 2005]

### **§ 3163.4 Failure to pay.**



[top](#)

If any person fails to pay an assessment or a civil penalty under §3163.1 or §3163.2 of this title after the order making the assessment or penalty becomes a final order, and if such person does not file a petition for judicial review in accordance with this subpart, or, after a court in an action brought under this subpart has entered a final judgment in favor of the Secretary, the court shall have jurisdiction to award the amount assessed plus interest from the date of the expiration of the 90-day period provided by §3165.4(e) of this title. The Federal Oil and Gas Royalty Management Act requires that any judgment by the court shall include an order to pay.

[52 FR 5394, Feb. 20, 1987; 52 FR 10225, Mar. 31, 1987]

### **§ 3163.5 Assessments and civil penalties.**



[top](#)

(a) Assessments made under §3163.1 of this title are due upon issuance and shall be paid within 30 days of receipt of certified mail written notice or personal service, as directed by the authorized officer in the notice. Failure to pay assessed damages timely will be subject to late payment charges as prescribed under Title 30 CFR Group 202.

(b) Civil penalties under §3163.2 of this title shall be paid within 30 days of completion of any final order of the Secretary or the final order of the Court.

(c) Payments made pursuant to this section shall not relieve the responsible party of compliance with the regulations in this part or from liability for waste or any other damage. A waiver of any particular

assessment shall not be construed as precluding an assessment pursuant to §3163.1 of this title for any other act of noncompliance occurring at the same time or at any other time. The amount of any civil penalty under §3163.2 of this title, as finally determined, may be deducted from any sums owing by the United States to the person charged.

[47 FR 47765, Oct. 27, 1982. Redesignated and amended at 48 FR 36583–36586, Aug. 12, 1983; 49 FR 37368, Sept. 21, 1984; 52 FR 5394, Feb. 20, 1987; 52 FR 10225, Mar. 31, 1987; 53 FR 17364, May 16, 1988]

### § 3163.6 Injunction and specific performance.


[top](#)

(a) In addition to any other remedy under this part or any mineral leasing law, the Attorney General of the United States or his designee may bring a civil action in a district court of the United States to:

- (1) Restrain any violation of the Federal Oil and Gas Royalty and Management Act or any mineral leasing law of the United States; or
- (2) Compel the taking of any action required by or under the Act or any mineral leasing law of the United States.

(b) A civil action described in paragraph (a) may be brought only in the United States district court of the judicial district wherein the act, omission or transaction constituting a violation under the Act or any other mineral leasing law occurred, or wherein the defendant is found or transacts business.

[49 FR 37368, Sept. 21, 1984]

### Subpart 3164—Special Provisions


[top](#)

### § 3164.1 Onshore Oil and Gas Orders.


[top](#)

(a) The Director is authorized to issue Onshore Oil and Gas Orders when necessary to implement and supplement the regulations in this part. All orders will be published in the Federal Register both for public comment and in final form.

(b) These Orders are binding on operating rights owners and operators, as appropriate, of Federal and restricted Indian oil and gas leases which have been, or may hereafter be, issued. The Onshore Oil and Gas Orders listed below are currently in effect:

Order No.	Subject	Effective date	Federal Register reference	Supersedes
1.	Approval of operations	May 7, 2007	71 FR	NTL–6.
2.	Drilling	Dec. 19, 1988	53 FR 46790	None.
3.	Site security	Mar. 27, 1989	54 FR 8056	NTL–7.
4.	Measurement of oil	Aug. 23, 1989	54 FR 8086	None.
5.	Measurement of gas	Mar. 27, 1989, new facilities greater than 200 MCF production; Aug. 23, 1989, existing facility greater than	54 FR 8100	None.

		200 MCF production; Feb. 26, 1990, existing facility less than 200 MCF production		
6.	Hydrogen sulfide operations	Jan. 22, 1991	55 FR 48958	None.
7.	Disposal of produced water	October 8, 1993	58 FR 47354	NTL-2B

Note: Numbers to be assigned sequentially by the Washington Office as proposed Orders are prepared for publication.

[47 FR 47765, Oct. 27, 1982. Redesignated at 48 FR 36583-36586, Aug. 12, 1983, and amended at 48 FR 48921, Oct. 21, 1983; 48 FR 56226, Dec. 20, 1983; 53 FR 17364, May 16, 1988; 54 FR 8060, Feb. 24, 1989; 54 FR 8092, Feb. 24, 1989; 54 FR 8106, Feb. 24, 1989; 54 FR 39527, 39529, Sept. 27, 1989; 56 FR 48967, Nov. 23, 1991; 57 FR 3025, Jan. 27, 1992; 58 FR 47361, Sept. 8, 1993; 58 FR 58505, Nov. 2, 1993; 72 FR 10328, Mar. 7, 2007]

#### § 3164.2 NTL's and other implementing procedures.



(a) The authorized officer is authorized to issue NTL's when necessary to implement the onshore oil and gas orders and the regulations in this part. All NTL's will be issued after notice and opportunity for comment.

(b) All NTL's issued prior to the promulgation of these regulations shall remain in effect until modified, superseded by an Onshore Oil and Gas Order, or otherwise terminated.

(c) A manual and other written instructions will be used to provide policy and procedures for internal guidance of the Bureau of Land Management.

#### § 3164.3 Surface rights.



(a) Operators shall have the right of surface use only to the extent specifically granted by the lease. With respect to restricted Indian lands, additional surface rights may be exercised when granted by a written agreement with the Indian surface owner and approved by the Superintendent of the Indian agency having jurisdiction.

(b) Except for the National Forest System lands, the authorized officer is responsible for approving and supervising the surface use of all drilling, development, and production activities on the leasehold. This includes storage tanks and processing facilities, sales facilities, all pipelines upstream from such facilities, and other facilities to aid production such as water disposal pits and lines, and gas or water injection lines.

(c) On National Forest System lands, the Forest Service shall regulate all surface disturbing activities in accordance with Forest Service regulations, including providing to the authorized officer appropriate approvals of such activities.

[47 FR 47765, Oct. 27, 1982. Redesignated and amended at 48 FR 36583-36586, Aug. 12, 1983, further amended at 53 FR 17364, May 16, 1988; 53 FR 22847, June 17, 1988]

#### § 3164.4 Damages on restricted Indian lands.



Assessments for damages to lands, crops, buildings, and to other improvements on restricted Indian lands shall be made by the Superintendent and be payable in the manner prescribed by said official.

## **Subpart 3165—Relief, Conflicts, and Appeals**



[top](#)

### **§ 3165.1 Relief from operating and producing requirements.**



[top](#)

(a) Applications for relief from either the operating or the producing requirements of a lease, or both, shall be filed with the authorized officer, and shall include a full statement of the circumstances that render such relief necessary.

(b) The authorized officer shall act on applications submitted for a suspension of operations or production, or both, filed pursuant to §3103.4–4 of this title. The application for suspension shall be filed with the authorized officer prior to the expiration date of the lease; shall be executed by all operating rights owners or, in the case of a Federal unit approved under part 3180 of this title, by the unit operator on behalf of the committed tracts or by all operating rights owners of such tracts; and shall include a full statement of the circumstances that makes such relief necessary.

(c) If approved, a suspension of operations and production will be effective on the first of the month in which the completed application was filed or the date specified by the authorized officer. Suspensions will terminate when they are no longer justified in the interest of conservation, when such action is in the interest of the lessor, or as otherwise stated by the authorized officer in the approval letter.

[47 FR 47765, Oct. 27, 1982. Redesignated and amended at 48 FR 36583–36586, Aug. 12, 1983, further amended at 53 FR 17364, May 16, 1988; 61 FR 4752, Feb. 8, 1996]

#### **§ 3165.1-1 Relief from royalty and rental requirements.**



[top](#)

Applications for any modification authorized by law of the royalty or rental requirements of a lease for lands of the United States shall be filed in the office of the authorized officer having jurisdiction of the lands. (For other regulations relating to royalty and rental relief, and suspension of operations and production, see part 3103 of this title.)

[48 FR 36586, Aug. 12, 1983, as amended at 53 FR 17365, May 16, 1988]

### **§ 3165.2 Conflicts between regulations.**



[top](#)

In the event of any conflict between the regulations in this part and the regulations in title 25 CFR concerning oil and gas operations on Federal and Indian leaseholds, the regulations in this part shall govern with respect to the obligations in the conduct of oil and gas operations, acts of noncompliance, and the jurisdiction and authority of the authorized officer.

[47 FR 47765, Oct. 27, 1982. Redesignated and amended at 48 FR 36583–36586, Aug. 12, 1983, further amended at 53 FR 17365, May 16, 1988]

### **§ 3165.3 Notice, State Director review and hearing on the record.**



[top](#)

(a) *Notice.* Whenever an operating rights owner or operator, as appropriate, fails to comply with any provisions of the lease, the regulations in this part, applicable orders or notices, or any other appropriate orders of the authorized officer, written notice shall be given the appropriate party and the lessee(s) to remedy any defaults or violations. Written orders or a notice of violation, assessment, or proposed

penalty shall be issued and served by personal service by an authorized officer or by certified mail. Service shall be deemed to occur when received or 7 business days after the date it is mailed, whichever is earlier. Any person may designate a representative to receive any notice of violation, assessment, or proposed penalty on his/her behalf. In the case of a major violation, the authorized officer shall make a good faith effort to contact such designated representative by telephone to be followed by a written notice. Receipt of notice shall be deemed to occur at the time of such verbal communication, and the time of notice and the name of the receiving party shall be confirmed in the file. If the good faith effort to contact the designated representative is unsuccessful, notice of the major violation may be given to any person conducting or supervising operations subject to the regulations in this part. In the case of a minor violation, written notice shall be provided as described above. A copy of all orders, notices, or instructions served on any contractor or field employee or designated representative shall also be mailed to the operator. Any notice involving a civil penalty shall be mailed to the operating rights owner.

(b) *State Director review.* Any adversely affected party that contests a notice of violation or assessment or an instruction, order, or decision of the authorized officer issued under the regulations in this part, may request an administrative review, before the State Director, either with or without oral presentation. Such request, including all supporting documentation, shall be filed in writing with the appropriate State Director within 20 business days of the date such notice of violation or assessment or instruction, order, or decision was received or considered to have been received and shall be filed with the appropriate State Director. Upon request and showing of good cause, an extension for submitting supporting data may be granted by the State Director. Such review shall include all factors or circumstances relevant to the particular case. Any party who is adversely affected by the State Director's decision may appeal that decision to the Interior Board of Land Appeals as provided in §3165.4 of this part.

(c) *Review of proposed penalties.* Any adversely affected party wishing to contest a notice of proposed penalty shall request an administrative review before the State Director under the procedures set out in paragraph (b) of this section. However, no civil penalty shall be assessed under this part until the party charged with the violation has been given the opportunity for a hearing on the record in accordance with section 109(e) of the Federal Oil and Gas Royalty Management Act. Therefore, any party adversely affected by the State Director's decision on the proposed penalty, may request a hearing on the record before an Administrative Law Judge or, in lieu of a hearing, may appeal that decision directly to the Interior Board of Land Appeals as provided in §3165.4(b)(2) of this part. If such party elects to request a hearing on the record, such request shall be filed in the office of the State Director having jurisdiction over the lands covered by the lease within 30 days of receipt of the State Director's decision on the notice of proposed penalty. Where a hearing on the record is requested, the State Director shall refer the complete case file to the Office of Hearings and Appeals for a hearing before an Administrative Law Judge in accordance with part 4 of this title. A decision shall be issued following completion of the hearing and shall be served on the parties. Any party, including the United States, adversely affected by the decision of the Administrative Law Judge may appeal to the Interior Board of Land Appeals as provided in §3163.4 of this title.

(d) *Action on request for State Director review. Action on request for administrative review.* The State Director shall issue a final decision within 10 business days of the receipt of a complete request for administrative review or, where oral presentation has been made, within 10 business days therefrom. Such decision shall represent the final Bureau decision from which further review may be obtained as provided in paragraph (c) of this section for proposed penalties, and in §3165.4 of this title for all decisions.

(e) *Effect of request for State Director review or for hearing on the record.* (1) Any request for review by the State Director under this section shall not result in a suspension of the requirement for compliance with the notice of violation or proposed penalty, or stop the daily accumulation of assessments or penalties, unless the State Director to whom the request is made so determines.

(2) Any request for a hearing on the record before an administrative law judge under this section shall not result in a suspension of the requirement for compliance with the decision, unless the administrative law judge so determines. Any request for hearing on the record shall stop the accumulation of additional daily penalties until such time as a final decision is rendered, except that within 10 days of receipt of a request for a hearing on the record, the State Director may, after review of such request, recommend that the Director reinstate the accumulation of daily civil penalties until the violation is abated. Within 45 days of the filing of the request for a hearing on the record, the Director may reinstate the accumulation of civil penalties if he/she determines that the public interest requires a reinstatement of the accumulation and that the violation is causing or threatening immediate, substantial and adverse impacts on public health and safety, the environment, production accountability, or royalty income. If the Director does not reinstate the daily accumulation within 45 days of the filing of the request for a hearing on the record, the suspension shall continue.

[52 FR 5394, Feb. 20, 1987; 52 FR 10225, Mar. 31, 1987, as amended at 53 FR 17365, May 16, 1988; 66 FR 1894, Jan. 10, 2001]

**§ 3165.4 Appeals.**[top](#)

(a) *Appeal of decision of State Director.* Any party adversely affected by the decision of the State Director after State Director review, under §3165.3(b) of this title, of a notice of violation or assessment or of an instruction, order, or decision may appeal that decision to the Interior Board of Land Appeals pursuant to the regulations set out in part 4 of this title.

(b) *Appeal from decision on a proposed penalty after a hearing on the record.* (1) Any party adversely affected by the decision of an Administrative Law Judge on a proposed penalty after a hearing on the record under §3165.3(c) of this title may appeal that decision to the Interior Board of Land Appeals pursuant to the regulations in part 4 of this title.

(2) In lieu of a hearing on the record under §3165.3(c) of this title, any party adversely affected by the decision of the State Director on a proposed penalty may waive the opportunity for such a hearing on the record by appealing directly to the Interior Board of Land Appeals under part 4 of this title. However, if the right to a hearing on the record is waived, further appeal to the District Court under section 109(j) of the Federal Oil and Gas Royalty Management Act is precluded.

(c) *Effect of an appeal on an approval/decision by a State Director or Administrative Law Judge.* All decisions and approvals of a State Director or Administrator Law Judge under this part shall remain effective pending appeal unless the Interior Board of Land Appeals determines otherwise upon consideration of the standards stated in this paragraph. The provisions of 43 CFR 4.21(a) shall not apply to any decision or approval of a State Director or Administrative Law Judge under this part. A petition for a stay of a decision or approval of a State Director or Administrative Law Judge shall be filed with the Interior Board of Land Appeals, Office of Hearings and Appeals, Department of the Interior, and shall show sufficient justification based on the following standards:

- (1) The relative harm to the parties if the stay is granted or denied,
- (2) The likelihood of the appellant's success on the merits,
- (3) The likelihood of irreparable harm to the appellant or resources if the stay is not granted, and
- (4) Whether the public interest favors granting the stay.

Nothing in this paragraph shall diminish the discretionary authority of a State Director or Administrative Law Judge to stay the effectiveness of a decision subject to appeal pursuant to paragraph (a) or (b) of this section upon a request by an adversely affected party or on the State Director's or Administrative Law Judge's own initiative. If a State Director or Administrative Law Judge denies such a request, the requester can petition for a stay of the denial decision by filing a petition with the Interior Board of Land Appeals that addresses the standards described above in this paragraph.

(d) *Effect of appeal on compliance requirements.* Except as provided in paragraph (d) of this section, any appeal filed pursuant to paragraphs (a) and (b) of this section shall not result in a suspension of the requirement for compliance with the order or decision from which the appeal is taken unless the Interior Board of Land Appeals determines that suspension of the requirements of the order or decision will not be detrimental to the interests of the lessor or upon submission and acceptance of a bond deemed adequate to indemnify the lessor from loss or damage.

(e) *Effect of appeal on assessments and penalties.* (1) Except as provided in paragraph (d)(3) of this section, an appeal filed pursuant to paragraph (a) of this section shall suspend the accumulation of additional daily assessments. However, the pendency of an appeal shall not bar the authorized officer from assessing civil penalties under §3163.2 of this title in the event the operator has failed to abate the violation which resulted in the assessment. The Board of Land Appeals may issue appropriate orders to coordinate the pending appeal and the pending civil penalty proceeding.

(2) Except as provided in paragraph (d)(3) of this section, an appeal filed pursuant to paragraph (b) of this section shall suspend the accumulation of additional daily civil penalties.

(3) When an appeal is filed under paragraph (a) or (b) of this section, the State Director may, within 10 days of receipt of the notice of appeal, recommend that the Director reinstate the accumulation of assessments and daily civil penalties until such time as a final decision is rendered or until the violation is abated. The Director may, if he/she determines that the public interest requires it, reinstate such accumulation(s) upon a finding that the violation is causing or threatening immediate substantial and adverse impacts on public health and safety, the environment, production accountability, or royalty

income. If the Director does not act on the recommendation to reinstate the accumulation(s) within 45 days of the filing of the notice of appeal, the suspension shall continue.

(4) When an appeal is filed under paragraph (a) of this section from a decision to require drainage protection, BLM's drainage determination will remain in effect during the appeal, notwithstanding the provisions of 43 CFR 4.21. Compensatory royalty and interest determined under 30 CFR Part 218 will continue to accrue throughout the appeal.

(f) *Judicial review.* Any person who is aggrieved by a final order of the Secretary under this section may seek review of such order in the United States District Court for the judicial district in which the alleged violation occurred. Because section 109 of the Federal Oil and Gas Royalty Management Act provides for judicial review of civil penalty determinations only where a person has requested a hearing on the record, a waiver of such hearing precludes further review by the district court. Review by the district court shall be on the administrative record only and not de novo. Such an action shall be barred unless filed within 90 days after issuance of final decision as provided in §4.21 of this title.

[52 FR 5395, Feb. 20, 1987; 52 FR 10225, Mar. 31, 1987, as amended at 53 FR 17365, May 16, 1988; 57 FR 9013, Mar. 13, 1992; 66 FR 1894, Jan. 10, 2001]

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