

INTERIOR BOARD OF LAND APPEALS

Benson-Montin-Greer Drilling Corp.

146 IBLA 387 (December 9, 1998)

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Editor's Note: Reconsideration denied by Order dated April 13, 1999

BENSON-MONTIN-GREER DRILLING CORP.

IBLA 96-485

Decided December 9, 1998

Appeal from a decision of the Deputy Commissioner of Indian Affairs, Bureau of Indian Affairs, denying an appeal of a Minerals Management Service order requiring the recalculation and payment of amounts due on Jicarilla Apache Tribal leases. MMS-89-0391-IND.

Affirmed in part, as modified; reversed in part.

1. Accounts: Payments--Administrative Authority: Generally--Indians: Leases and Permits: Generally--Indians: Mineral Resources: Oil and Gas: Royalties--Oil and Gas Leases: Royalties: Generally--Statute of Limitations

A statute establishing time limitations for the commencement of judicial actions for damages on behalf of the United States does not limit administrative proceedings within the Department of the Interior.

2. Contracts: Construction and Operation: General Rules of Construction--Indians: Leases and Permits: Generally--Indians: Mineral Resources: Oil and Gas: Royalties

The Board's task when faced with construing a contract is to determine and give effect to the intent of the parties as gleaned from the instrument as a whole, according a reasonable interpretation to all parts of the instrument and ascribing to the contract language its ordinary and commonly accepted meaning. When an agreement between an oil and gas lessee and a Tribal lessor grants the Tribal lessor a 50-percent interest in net profits of production from certain Tribal properties and creates a net profits account into which the proceeds of all oil, gas, and other hydrocarbons accruing to the Tribal interest from those properties will

be credited and against which all the allowable costs and expenses incurred by the lessee in developing, operating, equipping, and maintaining the properties will be charged, MMS properly requires the lessee to credit the received tertiary incentive revenue attributable to those properties in the net profits accounting.

3. Attorney Fees: Equal Access to Justice Act: Adversary Adjudication–Equal Access to Justice Act: Adversary Adjudication–Equal Access to Justice Act: Application

A request for an award of costs and attorney fees under the Equal Access to Justice Act, 5 U.S.C. § 504 (1994), will be denied where there has been no adversary adjudication as defined by 43 C.F.R. §§ 4.602(b) and 4.603(a).

APPEARANCES: Michael G. Maloney, Esq., Austin, Texas, for Benson-Montin-Greer Drilling Corporation; Peter J. Schaumberg, Esq., Howard W. Chalker, Esq., Geoffrey Heath, Esq., Sarah L. Inderbitzen, Esq., and Lisa K. Hemmer, Esq., Office of the Solicitor, U.S. Department of the Interior, Washington, D.C., for the Minerals Management Service.

OPINION BY DEPUTY CHIEF ADMINISTRATIVE JUDGE HARRIS

Benson-Montin-Greer Drilling Corporation (BMG) has appealed a January 26, 1996, decision of the Deputy Commissioner of Indian Affairs (Deputy Commissioner), Bureau of Indian Affairs (BIA), denying its appeal of a November 15, 1989, Minerals Management Service (MMS) order directing BMG to perform a restructured accounting of the Jicarilla Apache Tribe's (Tribe) net profits account to include all expenses and revenues related to Tribal leases committed to the East Puerto Chiquito Mancos Unit (EPCMU) during the period August 1980 through January 1981, including \$876,971 of tertiary incentive revenue, and to pay the additional net profits share and royalties due.

BMG is the lessee of Tribal oil and gas lease Nos. 235, 237, 238, 287, and 432, embracing lands within T. 27 N., R. 1 E., and T. 27 N., R. 1 W., New Mexico Principal Meridian (NMPM), Rio Arriba County, New Mexico. On October 18, 1979, BMG and the Tribe executed a Joint Development Contract (Contract) authorizing the cooperative development of the oil and gas under the unleased S½ sec. 16, T. 27 N., R. 1 E., NMPM, and Tribal lease Nos. 235, 238, and 432.

On October 18, 1979, BMG and the Tribe also entered into a Secondary Recovery Unit Program Agreement (Agreement) covering land included within the five Tribal leases and the S½ sec. 16, which together comprised the

EPCMU. 1/ The Agreement divided the affected lands into two distinct groups with different royalty rate provisions. The lands within Tribal lease Nos. 235, 238, and 432 and the S $\frac{1}{2}$ sec. 16 were designated as "235-238-432-Section 16" lands and were subject to a royalty rate of 1/6 of the value of production (16.67 percent) until payout and a 50 percent net profits interest thereafter. See Agreement at 6, section 8. 2/ The lands within Tribal lease Nos. 237 and 287 covered by the EPCMU were denoted as "237-287" lands (Agreement at 4, section 5) and had an initial royalty rate of 12 $\frac{1}{2}$ percent which escalated to 25 percent, under certain circumstances. See Agreement at 11, section 11.

Section 10 of the Agreement defined the net profits interest accruing to the "235-238-432-Section 16" lands. This section, which is pivotal to this appeal, states:

In this Section 10, the "235-238-432-Section 16" lands shall be called the "properties". Also for the purposes of this Section 10 the share of the proceeds from the sale of all oil, gas and other hydrocarbons which accrue after the effective date of the unit, after deducting all proceeds of production accruing to the Tribe's share of production (subject to the Joint Development Contract between the Tribe and BMG as to these tracts) and taxes legally assessed and payable measured by production, will hereafter be referred to as the "Tribal Interest".

There is hereby assigned 50% of all oil, gas and other hydrocarbons that may be allocated to the properties that accrue after the effective date to the Tribal interest; less, however, that part of such 50% interest in the production accruing to the interest, the proceeds of which are equal to 50% of all costs incurred after the effective date by BMG in developing, operating, equipping and maintaining the properties as hereinafter set forth, it being the intention of the parties that BMG will

1/ In a letter dated Dec. 14, 1978, BMG proposed to the Tribe that the EPCMU be formed for secondary recovery purposes. Copies of the proposed unit agreement and unit operating agreement were apparently attached to the Agreement although no such copies have been included in the case file. BMG asserts that the Tribe approved the EPCMU on Nov. 2, 1979 (see Statement of Reasons (SOR), Appendix 1 at 1), and it appears that the unit agreements were executed on June 1, 1980. See Nov. 15, 1989, MMS Order at 1.

2/ Although the Agreement indicated that the term "payout" was defined in the Contract, we have found no such definition in the Contract, even though the Contract itself refers to "payout as defined in this Joint Development Contract." See Contract at 4, paragraph 3. MMS defines payout as the point at which the proceeds from the sale of lease production exceed the lessee's costs of developing, operating, and maintaining the EPCMU. See Answer at 1 n.3.

cause to be assigned, as the net profits interest, 50% of the net profits, if any, that are realized by BMG from ownership, maintenance, development and operation of the properties in accordance with the terms and provisions hereof.

*** [T]he interest hereby assigned to the Tribe is exclusively an interest in net profits, as hereafter defined, and the Tribe shall look exclusively to the oil, gas and other hydrocarbons produced from the properties for the satisfaction and realization of the net profits interest.

BMG shall pay all costs and expenses incurred after the effective date in developing, operating, equipping and maintaining the properties, ***. BMG shall have exclusive charge and control of the marketing of all oil, gas and other hydrocarbons allocable to the net profits interest and shall market such production proportionately with and on the same terms as the Tribe's share of the production from the properties and shall collect and receive the proceeds of the sale of all such production; provided, however, that the Tribe shall at all times have the right to take its share of production in kind, on six months notice, subject to federal statutes and applicable regulations.

* * * * *

Into the net profits account shall be credited the proceeds of all oil, gas and hydrocarbons accruing to the Tribal interest after the effective date.

Against the net profits account shall be charged the following:

All costs and expenses incurred by BMG after the effective date in developing, operating, equipping and maintaining the properties (including costs of gas or water injection, pressure maintenance or requisite related facilities) ***.

The charges provided above shall be reduced by all other monies and the market value at the time of receipt of all other things of value received by BMG by virtue of the ownership of the properties and personal property and equipment located thereon or used in connection therewith, exclusive of the sale price of its interest in the properties should BMG sell all or any part of its interest therein subject to the net profits interest. Such credit items shall be taken into account solely for determination as to whether net profits exist and the Tribe shall have no interest therein. These credit items are limited to those installed after the effective date of the unit; it being

the intention of the parties that personal property and equipment now installed be excluded in the accounting of equipment costs or credits.

All credits to the net profits account shall be applied to the unliquidated balance of the above items. The total net profits from the properties shall be determined by deducting the total charges properly made against the net profits account from the total credits properly made into it, and the Tribe shall participate in 50% of the net profits derived from the properties as herein provided only after and while all charges properly charged against the net profits account shall have been recovered from the credits made into such account and a credit balance shall exist therein as of the date of distribution.

* * * * *

The Tribe shall never be responsible for the payment of any part of the costs and expenses charged against the net profits account or for any liabilities incurred in connection with the ownership, development, operation and maintenance of the properties and BMG covenants with the Tribe to hold the Tribe harmless from any and all such responsibility and liability: provided, however, all such costs and expenses shall nevertheless be charged against the net profits account to the extent herein provided.

(Agreement at 7-11.)

Section 11 of the Agreement set variable royalty provisions for Tribal lease Nos. 237 and 287:

[F]or any month following that in which the cumulative (from the effective date of unitization) expense exceeds the cumulative income, the Tribe's royalty rate shall be 12-1/2% and for any month following a month in which the cumulative income exceeds the cumulative costs, the Tribe's royalty rate shall be 25%. For the purposes of this Section 11 "income" means gross proceeds of production allocated to the subject leases after deducting all royalties and taxes legally payable measured by production and "costs" means that share allocated to each of these leases of all unit costs of drilling, completing and equipping wells and in developing, operating, equipping and maintaining the unit facilities (including costs of gas or water injection, pressure maintenance or requisite related facilities) * * *.

(Agreement at 11.)

In 1979, pursuant to the mandate of the Energy Conservation and Production Act of 1976, 15 U.S.C. § 757(j)(1) (1982), directing the amendment

of oil price control regulations established under the Emergency Petroleum Allocation Act of 1975 (EPAA), 15 U.S.C. §§ 753(a), 757(a) (1976), to "provide additional price incentives for bona fide tertiary enhanced recovery techniques," ^{3/} the Department of Energy (DOE) adopted regulations, effective October 1, 1979, creating a tertiary incentive program. 44 Fed. Reg. 51148 (Aug. 30, 1979). This program permitted a "qualified producer" to charge a price higher than the EPAA ceiling price for crude oil in order to recover 75 percent of specified "recoupable allowed expenses" of qualified tertiary recovery projects. 10 C.F.R. § 212.78 (1980); see *Diamond Shamrock Corp. v. Edwards*, 510 F. Supp. 1376, 1381 (D. Del. 1981); *Pennzoil Oil & Gas, Inc.*, 109 IBLA 147, 148 (1989), *aff'd*, 751 F. Supp. 602 (1990), *aff'd*, 928 F.2d 1139 (TECA 1991). The difference between the regulated ceiling price and the higher market price (less any ad valorem or severance taxes attributable to the excess) was termed "tertiary incentive revenue." 10 C.F.R. § 212.78(c) (1980). The regulations defined a "qualified producer" as one who "possesses an interest in the property on which the project is located and contributes to the initiation or expansion of the project." 10 C.F.R. § 212.78(c) (1980). The regulations further provided that above-ceiling prices could be charged for crude oil produced from properties other than those involved in enhanced recovery projects if necessary to recover the allowed expenses. See 10 C.F.R. § 212.78(a)(2), (c) (1980); DOE Interpretation 1980-7, 45 Fed. Reg. 33951 (May 21, 1980).

BMG participated in the tertiary incentive program by qualifying the EPCMU as an enhanced recovery project and incurred \$1,227,190 in enhanced recovery project expenses (costs) on the EPCMU. For the period August 1980 through January 1981, BMG sold the production from the EPCMU at unregulated (above-ceiling) prices, receiving \$499,969 in tertiary incentive revenue. Because the proceeds from the EPCMU were insufficient to recoup all of BMG's costs, BMG also sold oil production from the Canada Ojitos Unit (COU) at unregulated prices, collecting an additional \$377,002. BMG charged all of the recoupable allowed expenses of the project against the Tribe's net profits account, but did not credit any of the total \$876,971 in tertiary incentive revenue to the net profits account. Throughout this period the Tribe took its royalty interest in kind.

By letter dated April 30, 1986, MMS notified BMG of the initiation of an audit of BMG's activities relating to Tribal leases and units involving Tribal leases for the period March 1, 1980, through February 28, 1986.

^{3/} "Tertiary enhanced recovery techniques" were defined as "extraordinary and high cost enhancement technologies of a type associated with tertiary applications including, to the extent that such techniques would be uneconomical without additional pricing incentives, miscible fluid or gas injection, chemical flooding, steam flooding, microemulsion flooding, in situ combustion, cyclic steam injection, polymer flooding, and caustic flooding and variations of the same. The President shall have authority to further define the term by rule." 15 U.S.C. § 757(j)(2) (1982). See 44 Fed. Reg. 51148 n.1 (Aug. 30, 1979).

In an order dated November 15, 1989, MMS directed BMG to perform a restructured accounting of the Tribe's net profits account to include all the expenses incurred and all revenues received as a result of BMG's participation in the enhanced recovery program and to pay the additional net profits share and royalties due. Specifically, MMS ordered BMG to credit the \$876,971 in tertiary incentive revenue collected from both the EPCMU and the COU to the Tribe's net profits account on a monthly basis as it was actually received during the period August 1980 through January 1981 and recalculate before and after payout royalties.

BMG appealed the MMS order to the Acting Deputy Commissioner of Indian Affairs, BIA, who issued a decision on February 2, 1994, modifying the order to recalculate royalties. The Acting Deputy Commissioner upheld MMS' finding that BMG had improperly computed the payout point by failing to credit the tertiary incentive revenue to the Tribe's net profits account. She concluded, however, that BMG's deduction of tertiary recovery costs from the net profits account should have been limited to 57.011 percent, i.e., the percentage of the total costs corresponding to the percentage of the total revenue received for production from the EPCMU (\$499,969 divided by \$876,971). She correspondingly held that only the \$499,969 in revenue directly attributable to sales of production from the EPCMU should have been included in the Tribe's net profits account. The Acting Deputy Commissioner therefore modified the MMS order to the extent it had demanded that all the tertiary incentive revenue as well as all the associated costs be included in the net profits account.

BMG appealed the Acting Deputy Commissioner's decision to the Board (IBLA 94-472). On February 1, 1995, MMS filed a motion to remand stating that "the case record is incomplete and does not support the decision." By order dated February 16, 1995, the Board granted the request, setting aside the decision and remanding the case for further action.

That action took the form of the January 26, 1996, decision presently under appeal. Therein, the Deputy Commissioner concluded that the 6-year Federal statute of limitations, 28 U.S.C. § 2415(a) (1994), did not apply to these administrative proceedings. She further found that the tertiary incentive revenue had no relevance to the base royalty which had been taken in kind and sold by the Tribe. However, she determined that, under the Agreement between BMG and the Tribe, all the tertiary incentive revenue received by BMG from both the EPCMU and the COU should have been considered in the net profits and payout accounting.

She construed the Agreement creating the net profits account as requiring BMG to deduct all costs and credit all income accruing from the enhanced recovery project in order to determine when the payout point had been reached. She therefore determined that BMG had violated the Agreement by charging all the enhanced recovery project's costs to the net profits account while refusing to credit the account with any of the \$876,971 in additional revenue realized due to the project. In so doing, she rejected BMG's contention that DOE regulations prohibited the Tribe, which was not

a qualified producer, from receiving tertiary incentive revenue, holding that DOE regulations could not limit the Secretary's royalty determinations and that the provisions of the Agreement controlled the interests in the leases. Since BMG had charged 100 percent of its enhanced recovery costs to the net profits account, the Deputy Commissioner found that BMG had improperly computed payout by failing to credit 100 percent of tertiary incentive revenue to that account. Accordingly, she directed BMG to credit the tertiary incentive revenue to the Tribe's net profits account on a monthly basis as it was actually received during the period August 1980 through January 1981 and to reflect in the account the effects of these adjustments on payout calculations for that period.

In its SOR, BMG raises three principal grounds for appeal of the Deputy Commissioner's decision: (1) tertiary incentive revenue should not be included in the net profits share and payout accounting for the Tribal leases; (2) tertiary incentive revenue relating to the COU should not be included in the net profits share or payout accounting for the EPCMU; and (3) the 6-year Federal statute of limitations bars MMS from demanding additional royalties and/or revision of net profits share proceeds or payout calculations. BMG contends that the Agreement and DOE regulations, not MMS' general royalty valuation authority and rules, control here because this dispute concerns nonroyalty oil and net profits and payout accounting. It asserts that the Agreement, which was developed for secondary recovery purposes, did not contemplate the inclusion of tertiary incentive revenue in the net profits account or payout accounting. BMG maintains that the Tribe declined the opportunity to participate in the tertiary recovery project as a cost bearing working interest owner and that its choice to remain solely a net profits interest owner precludes the Tribe from being considered a qualified producer entitled to receive tertiary incentive revenue.

BMG argues that, notwithstanding the treatment of tertiary incentive revenue attributable to production from the EPCMU in the net profits and payout accounting, absolutely no basis exists for including tertiary incentive revenue allocated to the COU in that accounting. According to BMG, the Agreement applies only to income and proceeds allotted to the Tribal leases, none of which is included in the COU. Since the tertiary incentive revenue received for COU production is not proceeds of EPCMU production, BMG maintains that, under the Agreement, this revenue should not be included in the EPCMU net profits and payout accounting.

While recognizing the Department's consistent position that the 6-year statute of limitations at 28 U.S.C. § 2415(a) (1994) does not apply to administrative proceedings, BMG nevertheless insists that Federal court precedent undermines that viewpoint. BMG asserts that the Department knew of its activities as early as 1981, yet took no action to recover the alleged underpayments until mid-1989, long after the end of the 6-year limitations period, and that the MMS payment demand is therefore time-barred. BMG also requests that it be awarded costs and attorney fees as provided in the Equal Access to Justice Act (EAJA), as amended, 5 U.S.C. § 504 (1994), because MMS' position in this proceeding is not substantially justified.

In its Answer, MMS asserts that 28 U.S.C. § 2415(a) (1994) does not bar the demand for payment of additional royalties and net profits share because the 6-year statute of limitations does not apply to administrative proceedings. MMS further argues that the tertiary incentive revenue BMG received must be included in the Tribe's net profits account because the Agreement dictates that all profits, including tertiary incentive revenue, must be credited to the net profits account, citing language in section 10 providing that charges against the account must be reduced by "all monies and * * * other things of value received by BMG by virtue of the ownership of the properties." Since tertiary incentive revenue clearly constitutes monies and a thing of value obtained by BMG by virtue of its ownership of the properties, MMS maintains that the revenue should have been credited to the Tribe's net profits account.

MMS contends that, contrary to BMG's assertions, the Agreement contemplated that all consideration paid to BMG with respect to the affected Tribal leases would be credited to the net profits account, explaining that, under the Agreement, the tertiary incentive revenue affects only the determination of whether net profits exist. MMS avers that BMG's failure to credit the net profits account with the tertiary incentive revenue delayed the payout point, and deprived the Tribe of earlier participation in the 50 percent net profits share and escalated rate outlined in the Agreement. Accordingly, MMS submits that the decision properly required BMG to credit 100 percent of the tertiary incentive revenue from both the EPCMU and the COU to the net profits account.

BMG's payment of royalty in kind did not discharge its obligation under the Agreement to credit the Tribe's net profits account with the tertiary incentive revenue, MMS insists, because the agency is not assessing additional royalty on the royalty in kind oil, but rather requiring BMG to accurately accredit the tertiary incentive revenue to the net profits account. Nor does the fact that the Tribe is not a qualified producer under DOE regulations preclude consideration of the tertiary incentive revenue in the net profits account, MMS submits, because the Agreement requires BMG to credit the account with that revenue, and relevant case law clarifies that entities other than qualified producers may benefit from tertiary incentive revenue. MMS argues that BMG treated the Tribe as a partner in the tertiary recovery program by charging the net profits account with the program's costs and must also credit the account with the revenues regardless of whether the Tribe is a qualified producer.

MMS insists that tertiary incentive revenue from both the EPCMU and the COU must be added to the Tribe's net profits account. MMS points out that, although BMG incurred all its recoupable allowed expenses on the EPCMU and charged all those expenses to the net profits account, revenues from the EPCMU were insufficient to recoup the expenses so BMG charged above-ceiling prices for production from the COU. MMS therefore maintains that the tertiary incentive revenue from the COU constitutes monies or other things of value BMG received as a result of its ownership and development of the tertiary incentive program on the EPCMU and was properly includable in the Tribe's net profits account.

Finally, MMS disputes BMG's request for costs and fees under the EAJA. MMS claims that BMG is not entitled to recover its costs and fees because no adversary adjudication within the meaning of the EAJA has taken place.

In reply, BMG again disputes the inclusion of tertiary incentive revenue attributable to the COU in the net profits and payout accounting, arguing that there is no factual or legal connection between the EPCMU and the COU. Citing language in sections 10 and 11 of the Agreement referring to the "properties" and the "subject leases," BMG maintains that the Tribe can only look to EPCMU production income for net profits and payout accounting. BMG denies that it received the COU tertiary incentive revenue by virtue of its ownership of the EPCMU lands, asserting that such revenue derived from its ownership of the completely unrelated COU lands. BMG reiterates that, under DOE regulations, the Tribe's failure to attain qualified producer status precludes it from receiving tertiary incentive revenue or having that revenue credited in net profits or payout accounting. BMG contends that case law addressing gross proceeds determinations does not apply to this situation which involves the application of DOE regulations and nonstandard contract language. BMG further submits that the "all monies language" in the Agreement was never intended to include tertiary incentive revenue and does not override the DOE regulations. Finally, BMG insists that this proceeding is an adversary adjudication under the EAJA by virtue of its pendency before the Office of Hearings and Appeals both previously and currently, and that it is entitled to recover costs and fees because MMS' position was not substantially justified.

In response, MMS disputes BMG's argument that none of the tertiary incentive revenue should be considered in determining the Tribe's net profits share interest because the Tribe is not a qualified producer, pointing out that BMG has charged all the expenses of the tertiary recovery project against the net profits account. MMS explains that since the Tribe only benefits derivatively from the tertiary incentive revenue by the use of that revenue to offset the costs of the tertiary recovery project previously charged against the net profits account, the fact that the Tribe is not a qualified producer is irrelevant. Nor are the DOE regulations controlling here, MMS submits, because they do not address the key issue of whether the lessee's receipt of the higher tertiary incentive price should be taken into account in determining net profits share. MMS dismisses BMG's contradictory position that the Agreement was never intended to cover tertiary incentive revenue yet allows the deduction of the costs of the tertiary recovery project from the net profits account. MMS also insists that the tertiary incentive revenue received from COU production must be considered in the net profits and payout accounting because BMG would not have been able to charge the higher prices for COU production if not for its ownership of the EPCMU leases on which it developed the tertiary recovery project. Again MMS emphasizes that the COU production revenue has relevance only to the determination of whether the costs of the project on the EPCMU have been recovered and, as a consequence, whether the net profits account has reached payout. Finally, MMS asserts that BMG's EAJA claim is grossly premature because there has not yet been a final disposition of this proceeding.

[1] As an initial matter, we reject BMG's contention that the 6-year Federal statute of limitations, 28 U.S.C. § 2415(a) (1994), precludes the MMS demands for the recalculation of the Tribe's net profits share and the payout point and the payment of additional amounts due. That section, which governs the time for commencing judicial actions brought by the United States, provides in part:

Subject to the provisions of section 2416 of this title, and except as otherwise provided by Congress, every action for money damages brought by the United States or an officer or agency thereof which is founded upon any contract express or implied in law or fact, shall be barred unless the complaint is filed within six years after the right of action accrues or within one year after final decisions have been rendered in applicable administrative proceedings required by contract or by law, whichever is later * * *.

28 U.S.C. § 2415(a) (1994). This Board has held numerous times that statutes establishing time limits for the commencement of judicial actions for damages on behalf of the United States do not limit administrative proceedings within the Department of the Interior conducted to determine liability and fix the amount the Government claims to be due. See, e.g., Santa Fe Minerals, Inc., 145 IBLA 317, 323 (1998); Cenex, Inc., 145 IBLA 254, 257 (1998); U.S. Oil and Refining Co., 137 IBLA 223, 230 (1996), and cases cited.

A demand for the recalculation and payment of additional monies owed for Tribal oil and gas leases is not a judicial action for money damages brought by the United States, but is an administrative action not subject to the statute of limitations. Id.; see S.E.R., Jobs for Progress, Inc. v. United States, 759 F.2d 1, 5 (Fed. Cir. 1985); Chevron U.S.A., Inc., 129 IBLA 151, 154 (1994); Alaska Statebank, 111 IBLA 300, 311-12 (1989). As the U.S. Court of Appeals for the Fifth Circuit stated in a September 7, 1994, order granting rehearing of its opinion in Phillips Petroleum Co. v. Johnson, 22 F.2d 616 (5th Cir. 1994), and affirming the district court's grant of summary judgment to the defendants in two of four consolidated cases:

The term "action for money damages" refers to a suit in court seeking compensatory damages. The plain meaning of the statute bars "every action for money damages" unless "the complaint is filed within six years." (Emphasis added.) Thus, actions for money damages are commenced by filing a complaint. Actions that do not involve the filing of a complaint are not "action[s] for money damages." Since the government has filed no complaint, the agency action is not a[n] action for money damages." Thus, [28 U.S.C.] § 2415 is no bar.

(Order at 3-4, quoted in Texaco Exploration and Production, Inc., 134 IBLA 267, 270-71 (1995).)

We are without authority to decide whether the statute of limitations would bar a judicial suit to collect any underpayments; such a determination would be made by the court before which any collection proceeding is brought. Cenex, Inc., *supra*; U.S. Oil & Refining Co., 137 IBLA at 231; see also Phillips Petroleum Co. v. Lujan, 951 F.2d 257, 259-60 (10th Cir. 1991). None of BMG's arguments persuades us that the 6-year limitation period in 28 U.S.C. § 2415(a) (1994) should be read expansively to apply to administrative proceedings. See Amoco Production Co., 144 IBLA 135, 139-40 (1998); Meridian Oil, Inc., 140 IBLA 135, 145-46 (1997). We, therefore, hold that 28 U.S.C. § 2415(a) (1994) does not prevent MMS from demanding that BMG include tertiary incentive revenue in the net profits and payout accounting and remit additional amounts due.

[2] The resolution of this appeal focuses on the proper interpretation of sections 10 and 11 of the Agreement which establish the net profits account and the variable royalty rate provisions, respectively. The Board's task when faced with the construction of a contract is to determine and give effect to the intent of the parties as gleaned from the instrument as a whole, according a reasonable interpretation to all parts of the instrument and ascribing to the contract language its ordinary and commonly accepted meaning. BHP Minerals International, Inc., 139 IBLA 269, 305-306 (1997); Asarco Inc., 116 IBLA 120, 126-27 (1990), and cases cited. The parties' intent should be ascertained from the words of the contract, when clear and explicit, as long as to do so would not lead to absurd consequences. BHP Minerals International, Inc., 139 IBLA at 306; Exxon Company, U.S.A., 118 IBLA 30, 36 (1991).

The crux of this dispute centers on whether the tertiary incentive revenue received by BMG to recoup the costs of the enhanced recovery project on the EPCMU must be credited to the net profits account, and, if so, whether the tertiary incentive revenue attributable to production from the COU, as well as the EPCMU, must be included in that account. MMS and BMG each emphasize different portions of section 10 as support for their respective positions.

Section 10, quoted extensively above, directs that "the proceeds of all oil, gas, and hydrocarbons accruing to the Tribal interest" will be credited to the net profits account and that charges against the account will be reduced by "all other monies and the market value at the time of receipt of all other things of value received by BMG by virtue of the ownership of the properties and personal property and equipment located thereon or used in connection therewith." (Agreement at 9.) Section 10 further clarifies that these credits "shall be taken into account solely for determination as to whether net profits exist and the Tribe shall have no interest therein." *Id.* However, section 10 also explicitly states that "the Tribe shall look exclusively to the oil, gas and other hydrocarbons produced from the properties for the satisfaction and realization of the net profits interest." (Agreement at 8 (emphasis added).) The Agreement states that "[i]n this Section 10 the '235-238-432-Section 16' lands shall be called the 'properties.'" *Id.* at 7.

Thus, while section 10 directs that the proceeds of all oil, gas, and hydrocarbons accruing to the Tribal interest will be credited to the net profits account, it limits that accrual to the oil, gas, and other hydrocarbons "produced from the properties," which are, in turn, limited to the "235-238-432-Section 16" lands. Because tertiary incentive revenue was part of the proceeds received by BMG from the oil, gas, and other hydrocarbons produced from the "properties," the Agreement requires the crediting of that revenue to the net profits account.

BMG attempts to avoid the all-inclusive language of section 10 by first insisting that the Agreement does not cover the tertiary recovery project developed on the EPCMU. However, BMG's deduction of the costs of the project from the net profits account established in the Agreement belies this claim. We also reject BMG's assertion that, under DOE regulations, the fact that the Tribe is not a qualified producer precludes inclusion of tertiary incentive revenue for net profits accounting purposes. As MMS correctly points out, the Tribe is not attempting to collect above-ceiling prices as a seller of its royalty in kind oil; rather, the tertiary incentive revenue must be included solely to determine whether any net profits exist and, if so, the Tribe's share of those profits. Given BMG's debiting of the net profits account with the costs of the enhanced recovery project, crediting that account with the tertiary incentive revenue received for production from the "properties" does not conflict with DOE's rationale for generally excluding royalty owners from sharing in such revenue, i.e., that royalty owners have incurred no expenses to recoup. See DOE Interpretation 1980-7, 45 Fed. Reg. 33952 (May 21, 1980); see also Pennzoil, 109 IBLA at 152 n.15. Accordingly, we find no impediment to construing the language of section 10 as requiring that tertiary incentive revenue from the "properties" be credited to the net profits account.

In her decision, the Deputy Commissioner did not distinguish between tertiary incentive revenue derived from the "properties" and that derived from the EPCMU, as a whole. Her decision authorized the inclusion of all EPCMU tertiary incentive revenue in the net profits account. We cannot find that the language of section 10 justifies such a broad interpretation. We must modify her decision and direct that only the tertiary incentive revenue attributable to production from the "properties" may be credited to the net profits account.

Likewise, we must modify her decision to the extent she allows BMG to charge against the net profits account all \$1,227,190 of its enhanced recovery costs on the EPCMU. Those costs must be limited to the costs associated with the "properties." Section 10 states that "[a]gainst the net profits account shall be charged the following: All cost and expenses incurred by BMG after the effective date in developing, operating, equipping and maintaining the properties * * *." (Agreement at 9.)

Although the parties have concentrated their arguments on the net profits account and have not explicitly discussed the escalated royalty

provisions of section 11 of the Agreement, we conclude that the language of that section requires the inclusion of tertiary incentive revenue attributable to lease Nos. 237 and 287 as "income," as well as allowing the enhanced recovery costs apportioned to those leases to be included in "costs," for the purpose of determining the months, if any, in which the royalty rate should have escalated from 12½ percent to 25 percent.

Section 11 defines "income" as meaning "gross proceeds of production allocated to the subject leases" minus certain royalties and taxes. (Agreement at 11.) In Pennzoil, 109 IBLA at 156, the Board held that tertiary incentive revenue is properly included within "gross proceeds" representing the value of production from Federal oil and gas leases. The parties' utilization of a term with a specific meaning in the Federal oil and gas lexicon signifies their intent to adopt that construction of the term. Thus, BMG must include the tertiary incentive revenue attributable to the two Tribal leases covered by section 11 in the calculations required by that section.

We turn now to the question whether tertiary incentive revenue attributable to the COU must be included in the section 10 net profits accounting for the EPCMU, as argued by MMS. We conclude that it should not be included.

The COU does not contain any section 10 "properties." In fact, the COU does not include any Tribal leases at all. We disagree with MMS' assertion that the section 10 language authorizing credits for "all monies and the market value * * * of all other things of value received by BMG by virtue of its ownership of the properties" is broad enough to include tertiary incentive revenue allotted to the COU production. MMS' position is that, but for BMG's ownership of the properties, it would not have been able to collect tertiary incentive revenues on production from the COU. However, MMS' construction would negate the language cited above specifically requiring the Tribe to "look exclusively to the oil, gas, and other hydrocarbons produced from the properties for the satisfaction and realization of the net profits interest." Accordingly, we reverse the Deputy Commissioner's decision to the extent it required BMG to credit the tertiary incentive revenue received for production from the COU to the net profits account.

[3] Finally, we deny BMG's request for costs and fees pursuant to the EAJA, 5 U.S.C. § 504 (1994), which authorizes the awarding of expenses and attorney fees to the prevailing party in an adversary adjudication. As an initial matter, we note that, while BMG claims that it is entitled to fees and expenses, it has failed to file a formal and complete application as required by 43 C.F.R. §§ 4.608-4.611. See Sigma M Explorations Inc., 145 IBLA 182, 192 (1998). In any event, the EAJA limits the award of fees and expenses to those incurred in connection with an adversary adjudication. An "adversary adjudication" is defined in relevant part as "an adjudication under section 554 of [Title 5] in which the position of the United States is represented by counsel or otherwise." 5 U.S.C.

§ 504(b)(1)(C)(i) (1994). By its own terms, 5 U.S.C. § 554 (1994) applies "in every case of adjudication required by statute to be determined on the record after opportunity for an agency hearing." See also 43 C.F.R. §§ 4.602(b), 4.603(a). Since there has been no adversary adjudication in this case, the EAJA does not apply and no award can be made. Sigma M Explorations Inc., supra; Herbert J. Hansen, 119 IBLA 29, 31 (1991).

To the extent not specifically addressed herein, the other arguments raised by BMG have been considered and rejected.

Therefore, pursuant to the authority delegated to the Board of Land Appeals by the Secretary of the Interior, 43 C.F.R. § 4.1, the Deputy Commissioner's decision is affirmed in part, as modified, and reversed in part.

Bruce R. Harris
Deputy Chief Administrative Judge

I concur:

Will A. Irwin
Administrative Judge