Report of the Public Lands Committee

I. Introduction

Perhaps the most notable event of 1992 was the passage of the long-awaited Energy Policy Act of 1992 (Act).[1] The Act, however, in its final form, is more notable for what it fails to address than for what it does address. The entire Outer Continental Shelf (OCS) chapter was eliminated by House and Senate conferees because of impasses over whether to pass a five-year ban on OCS drilling in certain areas and whether the government should buy back leases off the coasts of Alaska, Florida, and North Carolina. Also eliminated were programs for sharing federal OCS revenues with coastal governments, royalty relief for producers developing fields in more than 200 meters of water, and leasing bans on part of the Arctic National Wildlife Refuge (ANWR) in northern Alaska.[2] The Act does, however, give independent producers an estimated one billion dollars in tax breaks over the next five years as incentive to further domestic exploration.

II. Coal Lease Sales

The first coal lease sale in 1991 by the Bureau of Land Management (BLM) in the "second round" of leasing in the Powder River Basin in Wyoming has generated opposition and litigation by Wyoming environmental groups. Their challenge to the sale was rejected by the BLM and the BLM's decision was affirmed on appeal by the Interior Board of Land Appeals (IBLA or Board) on September 15, 1992 in *Powder River Basin Resource Council.*[3] The appellants' motion for reconsideration of that decision is pending before the IBLA.

In October 1989, Kerr-McGee Coal Corporation (Kerr-McGee) filed an application to lease certain federal coal lands adjacent to its existing Jacobs Ranch Mine Basin in Wyoming. Kerr-McGee's application was the first of a number of other applications filed by existing federal lessees to expand their operations and was twice amended at BLM's request to reconfigure the proposed lease tract to include certain other federal coal lands.

Kerr-McGee's initial application could only have been granted as an "emergency lease sale" of federal coal deposits that would otherwise be bypassed. However, with the decertification of the Powder River Regional Coal Team in 1990 by Secretary Lujan, federal coal in the basin became generally available by the "lease by application" provisions of the federal coal leasing regulations.[4]

A draft "environmental assessment" (EA) was prepared by BLM and was the subject of written comments and public hearings. Certain environ-

1. Pub. L. No. 102-486, 106 Stat. 2776 (1992)[hereinafter *Act*].
2. *See* H.R. Rep. No. 474, 102nd Cong., 2d Sess., (1992), *reprinted in* 1992 U.S.C.C.A.N. 1953.
3. 124 I.B.L.A. 83 (Sept. 15, 1992).
4. 43 C.F.R. § 3425.1-5 (1992).

mental groups argued that the National Environmental Policy Act (NEPA) required a "comprehensive" environmental impact statement (EIS) covering the entire Powder River Basin and focusing on the "cumulative" impacts of the Kerr-McGee lease and other pending lease applications on various regional resources, particularly groundwater. They also contended that the proposed lease sale would violate the competitive bidding requirements of the Federal Coal Leasing Amendments Act (FCLAA). The BLM addressed and rejected the environmental groups' arguments in its final EA and carried out the proposed lease sale. Kerr-McGee submitted the only bid and was declared the successful bidder.

The environmental groups filed an appeal of the Wyoming BLM State Director's decision with the IBLA, claiming that the BLM's EA failed to satisfy its obligations under NEPA and that the sale failed to implement the competitive bidding requirements of the FCLAA.

The BLM, Kerr-McGee, the State of Wyoming, and each supporting amici coal lease applicant moved to dismiss the appeal on the grounds that the appellants had failed to demonstrate that they had been "adversely affected," as required by the Department's appeal regulations. The appellants asserted a number of specific injuries to their individual members and also alleged a "general informational interest" of their organizations that would be injured if an EIS was not prepared.[5]

The IBLA affirmed the BLM decision. With respect to the "standing" issue, the IBLA found that several of the appellants had demonstrated "colorable allegations of adverse effect" that were adequate to sustain standing. The general environmental informational interest ground relied on by one of the appellant organizations was rejected by the Board and its appeal dismissed.[6]

On the merits, the Board rejected the appellants' NEPA claims. It found that the EA's analysis was properly "tiered" to earlier comprehensive EISs in the basin and had properly incorporated by reference more recent scientific studies on particular subjects. Specifically, the BLM's Finding Of No Significant Impact (FONSI), obviating preparation of an EIS, clearly satisfied the Board's precedents that a FONSI will be affirmed on appeal "if the record shows that a careful review of environmental problems has been made, relevant environmental concerns have been identified, and the final determination is reasonable."[7] The Board rejected the contention that the BLM had violated NEPA by failing to consider alternative tract configurations, pointing out that the tract as originally proposed by Kerr-McGee had been significantly reconfigured and that there were no other feasible configurations.[8] On this latter point, the Board also rejected appellants' contention that the sale as structured violated the competitive bidding requirements of the FCLAA, concluding that "nothing indicates that other entities were barred from bidding on coal offered, that fair market value was not received, or that maximum economic

5. 124 I.B.L.A. at 90.

6. *Id.*

7. *Id.* at 91.

8. *Id.*

recovery will not be achieved."[9]

On November 16, 1992, the appellants sought reconsideration of the Board's decision, contending that it did not adequately address their "cumulative impacts" argument and that certain information developed subsequent to the decision supported their argument that alternative tract configurations should have been considered. The BLM, Wyoming, and Kerr-McGee all responded that appellants had failed to demonstrate any of the "extraordinary circumstances" required by 43 C.F.R. § 4.403 to justify reconsideration.[10] As of February 1, 1993, no decision had been issued in response to appellants' motion. Meanwhile, an additional "maintenance" lease has been issued by BLM in the basin and the processing of several others continues.

III. ROYALTY PAYMENTS ON PUBLIC LANDS

Royalty payments on gas contract settlements continue to be a source of controversy among producers and the Department of Interior (DOI). In an audit report dated March 31, 1992, the DOI determined that the Minerals Management Service (MMS) "had not vigorously pursued the collection of royalties on proceeds received from contract settlements,"[11] and "identified $754 million in potential additional royalties due on the $4.68 billion in proceeds received by Federal and Indian lessees in gas contract settlements for the period 1982 through 1990."[12] The audit report addresses both "buydowns" and "buyouts" of gas contract settlements and advances four recommendations to facilitate and ensure enhanced collection of proper royalty payments on gas contract settlements. In evaluating the collection of royalty payments, the Inspector General relied on 30 C.F.R. § 206, which requires payment of royalties on the "gross proceeds accruing to the lessee," to support the historical position of the MMS that royalties are due "on all types of advanced payments made to Federal and Indian lessees in consideration for the sale of lease production."[13] Nevertheless, the Fifth Circuit Court of Appeals in *Diamond Shamrock Exploration Corp. v. Hodel*,[14] held that "no royalty is due on take-or-pay payments unless and until gas is actually produced and taken."[15]

While the Report estimated that enhanced royalty recovery on contract settlements would result in additional royalties of about $571 million for contract buydowns and $183 million for contract buyouts for the period 1982 through 1990, it noted that "royalties do not accrue on the contract settlement

9. *Id.* at 90.

10. 43 C.F.R. § 4.403 (1991).

11. OFFICE OF INSPECTOR GENERAL, U.S. DEPT. OF INTERIOR, GAS CONTRACT SETTLEMENTS, MINERAL MANAGEMENT SERVICE (1992).

12. Audit Report (attached Memorandum to the Assistant Secretary for Land and Minerals Management from the Assistant Inspector General to Audit Relative to Final Audit Report on Gas Contract Settlements) No. 92-I-657, MINERALS MANAGEMENT SERVICE, (March 31, 1992)[hereinafter *Report*].

13. *Id.* at 2.

14. 853 F.2d 1159, 1168 (5th Cir. 1988).

15. *But see* Frey v. Amoco Prod. Co., 943 F.2d 578 (5th Cir. 1991), *withdrawn in part*, 951 F.2d 67 (5th Cir. 1992) *reinstated in part*, 976 F.2d 242 (5th Cir. 1992) (royalty due on take-or-pay settlements in "amount realized" leases).

proceeds until the production to which they are related occurs."[16] A contract buydown usually involves a gas contract amendment by which the gas purchaser makes a lump-sum payment in order to reduce the price of future gas purchases and sometimes the amount of gas required under the original contract. The Report found that:

> [r]oyalties are not due when the settlement is made because the payment is based on future production. Instead, royalties become due on the proceeds received by a lessee in a contract buydown on an incremental basis when production occurs. The basis for allocating the proceeds received by the lessee to future production should be determined based on the specific facts contained in each settlement.[17]

Buyouts, by contrast, typically involve the termination rather than amendment of the original gas contract. In that case, the producer receives a lump-sum payment to compensate it for a loss of revenues on future production. Here, the Report recognized that royalties are not due until future production occurs.

The Report addresses the six-year statute of limitations and document retention requirements[18] noting that settlements beginning in 1985 are subject to review if such review were immediately instituted. The conclusion reached, however, is that "royalties on the payments received by lessees in contract settlements should be settled through negotiations between the Service and lessees."[19] The complexity of allocating lump-sum settlement payments to a particular lease or to that incremental portion of future production compelled this result. Specifically, the Report concluded that:

> [t]he payments received by Federal and Indian lessees to settle contract disputes are related to thousands of contracts and will have an impact on royalties paid on thousands of leases. To require lessees to account for the royalties on individual leases on a month-by-month basis would place a considerable burden on lessees' accounting resources. The Service would have to perform a review of the payments, and that review could adversely impact the Service's resources as well.[20]

Despite the repeated iterations that royalties are not due on the payments until production actually occurs, the Report concludes that "the immediate payment of the royalties at the time payments are received would be appropriate,"[21] ostensibly to offset added accounting and review costs. The "protection" offered for lessees who agree to such settlements is an explanation by MMS that "royalty payments are being made for future production and these payments would be subject to refund if the future production does not occur."[22] The Report does not address the limitations problems to which the lessees would be exposed in the event future production does not occur, nor does the Report address the problem raised by MMS response to the Report,

16. *Report, supra* note 12 at 5.

17. *Id.*

18. Federal Oil and Gas Royalty Management Act (FOGRMA), 30 U.S.C. §§ 1701-1757 (1988) (six-year document retention provision); 28 U.S.C. § 2415(a) (six-year statute of limitations on actions for money damages brought by the United States or an officer or agency thereof which is founded on contract).

19. *Report, supra* note 12 at 8.

20. *Id.*

21. *Id.*

22. *Id.*

that payments attributable to future production do not become royalty bearing when the payment is made, but only months and years later.[23]

The Report ultimately advances the following four recommendations that the Director, MMS:

1. Expedite the issuance of a policy to require lessees to report and pay royalties on proceeds received on gas contract buydowns and contract buyouts;
2. Inform Federal and Indian lessees that royalties are due on the proceeds received for gas contract buydowns and contract buyouts;
3. Conduct issue-based audits expeditiously of gas contract settlements on all major payors based on the issues raised in this report where it appears that substantial additional royalties are due;
4. Offer lessees the option of paying royalties due on contract settlements in one lump-sum payment to avoid costly additional accounting requirements.[24]

MMS response to the recommendations was to concur with recommendations 1 and 2, but to conclude that recommendations 3 and 4 were unnecessary.[25] Recommendation 3 is obviated, according to MMS, because there are ongoing issue-based audits of contract settlements of the major royalty payors with on-site residency staffs and other service auditors addressing this issue at other royalty payor companies.[26] Recommendation 4 is unnecessary because the Service already has procedures in place which are used by payors to report lump-sum royalties on a case-by-case basis. MMS concluded that "there have been no significant losses of royalties due to the current lack of audit bills for payments made on account of gas settlement agreements."[27]

The limitations issue addressed by the Report was discussed in the context of record retention in *Phillips Petroleum Co. v. Lujan*.[28] The court required the producers to retain records longer than the statutory six-year period where the MMS instituted an audit, forcing compliance with FOGRMA, which provides that a lessee must maintain lease records "for six years after the records are generated unless the Secretary notifies the record holder that he has initiated an audit or investigation involving such records and that such records must be maintained for a longer period."[29] The result is that producers must retain all records once an audit has been initiated. The *Phillips* court also supported the lower court's upholding of the MMS' decision to audit the producers on a company-wide, rather than on a lease-by-lease basis.[30] Subsequent to the *Phillips* case, the United States district court[31] held that MMS was barred under the six-year statute of limitations[32] from bringing any action to recover underpaid royalties on federal leases. Any action brought within the six-year statute of limitations was to be measured from the

23. *Id.* at 16 (app. 2).
24. *Id.* at 18-19 (app. 2).
25. *Id.*
26. *Id.* at 13-14 (app. 2).
27. *Id.* at 11 (app. 2)
28. 963 F.2d 1380 (10th Cir. 1992).
29. 30 U.S.C. § 1713(b) (1986).
30. 963 F.2d at 1385.
31. Phillips Petroleum Co. v. Kelly, Nos. 5, Civ. A. 3-89-CV-1707-H, 2393-H, 2727-H, & 2751-H, 1992 WL 387236, at *5 (N.D. Tex. Sept. 18, 1992).
32. 28 U.S.C. § 2415 (1992).

date the royalties were due and payable.[33]

In another royalty-related case, *Enron Oil & Gas Co. v. Lujan*,[34] the Fifth Circuit Court of Appeals upheld a MMS ruling that state severance tax reimbursements paid to the lessee by gas purchasers should be included as part of the lessee's "gross proceeds" in calculating royalty owed from federal leases.[35] Enron had various federal leases in Utah and Wyoming, in connection with which it excluded reimbursed state severance taxes from its royalty calculations. These taxes were included by Enron as charges to gas purchasers for which Enron was reimbursed. In holding that royalty was owed on the tax reimbursement payments, the court relied on the Mineral Leasing Act of 1920[36] (MLA) and the Natural Gas Policy Act of 1978[37] (NGPA), to conclude that:

> [t]he DOI has historically included state severance tax reimbursements in calculating 'gross proceeds' for royalty assessments, and Congress has not disrupted this practice, either expressly or imputedly. Passage of the NGPA did not disrupt, and was not intended to disrupt, this long-standing practice. Moreover, the practice of including state severance taxes in calculating 'gross proceeds' does not frustrate the intent of the NGPA. Finally, the DOI's practice finds support in the law of this circuit and other circuits.[38]

In a decision by the IBLA, a lessee's assessment of late payment interest charges was upheld even though the lessee, Anadarko Petroleum Corp., obtained a lump-sum payment for undervalued gas and immediately made payment to the MMS.[39] The dispute between Anadarko and its gas purchaser involved the classification of the gas as "wet" or "dry." Although initially classified as "wet," through Anadarko's efforts, the gas was later classified as "dry," resulting in the lump-sum payment. The MMS held that "[t]he fact that there was a dispute between Anadarko and its purchaser as to the proper gas measurement and resulting price does not relieve Anadarko form its duty to pay in accordance with the lease and MMS regulations."[40] The IBLA applied current departmental policy, and found no injury to the rights of others by such application:

> 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

33. 1992 WL 387236, at *13.
34. 978 F.2d 212 (5th Cir. 1992).
35. *Id.*
36. 30 U.S.C. §§ 181-287 (1986).
37. 15 U.S.C. §§ 3301-3432 (1982).
38. 978 F.2d at 216.
39. Anadarko Petroleum Corp., 123 I.B.L.A. 361 (July 21, 1992).
40. *Id.* (quoting the MMS decision).

benefits are received.[41]

Because Anadarko took no action for three years to force its purchaser to pay the higher "dry" gas price, IBLA found that Anadarko had not made "timely application for a price increase or benefit allowed under the contract under 30 C.F.R. § 206.152(j)."[42] Anadarko, therefore, was not excused from paying interest on late royalty payments.

In an effort "to encourage operators of Federal stripper oil properties to place marginal or currently uneconomical shut-in oil wells back in production and to provide the economic incentive to increase production by reworking such wells, drilling new wells, and/or by implementing enhanced oil recovery projects,"[43] the BLM cut the previous 12.5% royalty rate on stripper wells to 0.5% for the first barrel per day (b/d) of production plus 0.8% for each additional 1 b/d through 15 b/d. The DOI expects the new rule to result in increased production of 4.7 million barrels per year.

In another rulemaking, the MMS is "amending its regulations to allow payors to correct reporting errors under certain limited circumstances by offsetting production incorrectly reported and attributed to a Federal or Indian Tribal lease or leases against under-reported production on a different Federal or Indian Tribal lease or leases to which it should have been attributed."[44] The "cross-lease netting" will be allowed to eliminate late-payment interest only if all of the following criteria are met:

> (1) The error results from attributing and reporting an equal volume of production produced from a lease or leases during a particular production month to a different lease or leases from which it was not produced for that same or another production month;
> (2) The payor is the same for the lease or leases to which production was attributed and the lease or leases to which it should have been attributed;
> (3) The payor submits production reports, pipeline allocation reports, or other similar documentary evidence pertaining to the specific production involved which verifies the correct production information;
> (4) The lessor is same for the leases involved (in the case of Indian tribal leases, the same tribe is the lessor of both leases); and
> (5) The ultimate recipients of royalty revenues under permanent indefinite appropriations are the same for, and receive the same percentage of revenue from, the leases.[45]

Under the new section 230.51, refunds or overpayments of royalties attributable to production from leases governed by the Outer Continental Shelf Lands Act (OCSLA) may be offset in certain circumstances against underpayment of royalties attributable to another OCSLA lease upon submission of a written request to MMS providing adequate documentation.[46]

The DOI, recognizing that domestic oil and gas exploration, develop-

41. *Id.* at 366.

42. *Id.* at 367.

43. Promotion of Development, Reduction of Royalty on Stripper Wells, 57 Fed. Reg. 35,968 (1992) (to be codified at 43 C.F.R. § 3100).

44. Offsetting Incorrectly Reported Production Between Different Federal or Indian Leases (Cross-Lease Netting), 57 Fed. Reg. 62,200 (1992) (to be codified at 30 C.F.R. §§ 218 and 230).

45. 57 Fed. Reg. at 62,206 (1992).

46. 57 Fed. Reg. at 62,207 (1992).

ment, and production is at thirty-year lows, is continuing the rental rate reduction for onshore oil and gas leases in force issued prior to January 1, 1988. The rental rate reduction will continue through February 29, 1996 and will apply to "all simultaneous leases whose annual rental rates would otherwise have increased by regulation from $1 to $3 per acre."[47] The rental reduction was instituted by the DOI in 1986 and 1987.

IV. CONCLUSION

The final year of the Bush administration saw increased emphasis on domestic resource exploration, development, and production in the form of incentives to industry as well as an avowed determination to ensure maximum revenues through an aggressive plan of royalty valuation. Whether the gains, such as they are, achieved by industry will survive the Clinton administration remains to be seen.

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47. 57 Fed. Reg. at 62,352 (1992).