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Federal Oil & Gas Royalty Management in a Nutshell

Basic Principles

1. **Royalty is based on the "value of production" at the wellhead or lease.**

   - Federal mineral leasing statutes and longstanding Department of the Interior policy, precedents, and regulations require that royalty on oil and gas produced from federal lands be based on the "value of production" at the wellhead or lease.

   - For arm's length transactions, transactions involving a producer and third party, "gross proceeds," defined in Minerals Management Service regulations, less allowances for transportation and processing, is the usual measure of value.

   - For non-arm's length transactions, transactions involving a producer and an entity not deemed a third party under Minerals Management Service (MMS) regulations, some other surrogate measure must be used: benchmarks (e.g., comparable sales), index (e.g., spot prices, NYMEX futures prices). Where such surrogates are used, they are adjusted as needed to account for factors such as location, production quality (e.g., sweet v. sour gas, heavy crude v. light crude).

2. **When gas is sold away from the lease, the value of production is derived from downstream sales values by deducting the reasonable costs of transportation (oil & gas) and processing (gas only).**

   - For arm's length arrangements, the contract alone or a tariff may determine the magnitude of the deductible costs.

   - For non-arm's length arrangements, with limited exceptions, reasonable <u>actual costs</u> determine what costs are deductible.

3. **The costs of placing production in "marketable condition" and marketing the production are not deductible.**

   - Pursuant to regulation, the government does not share in the costs of placing production in "marketable condition" (e.g., removing water or impurities) or marketing production (e.g., trading or scheduling costs). These costs are separate from the allowable costs incurred for transportation and processing.

   - MMS regulations define "marketable condition," and the terms of sales contracts, typical for the field or area where a lease is located, are a good index of marketable condition.

4. **Absent clear, prescriptive standards in the federal mineral leasing statutes, the Department of the Interior and its Minerals Management Service wields broad discretion to determine "the value of production."**

   - Given the agency's mineral development and revenue raising mission on behalf of the US treasury and other government beneficiaries, agency discretion is used liberally and policy making is heavily tilted toward the agency.

Frequently Asked Questions

1. Who manages the federal royalty program and audits royalty payments?

The Minerals Management Service (MMS) Minerals Revenue Management group, located principally in Lakewood, CO, bears the responsibility for managing the collection of royalties for production on federal and Indian lands and disbursement of royalty shares to the US Treasury, states where federal production occurs and Indian tribes. As a part of that responsibility the MMS also audits royalty compliance, using its own auditors and cooperating with state and Indian auditors. Detailed MMS regulations appear at Title 30 of the Code of Federal Regulations.

2. How are royalty disputes resolved?

Audits often lead to MMS orders to pay, which can be appealed to the MMS director, the Interior Board of Land Appeals (IBLA) and federal courts. On occasion, decisions are rendered by the Assistant Secretary, which bypasses IBLA and allows appeal direct to the courts. Disputes can often be averted by procuring from the MMS the guidance described under question No. 4 below.

3. What are some common royalty dispute issues?

Non-arm's length transactions, associated with the sale of production or the purchase of services for allowance purposes (e.g., transportation, gas processing), generate many issues. Adoption of a benchmark system in 1988 was intended to ameliorate these problems, but continuing squabbles led to adoption of an indexing system for oil in 2001. Benchmarks are still employed for gas. Marketable condition, especially for gas (e.g., compression that satisfies marketable condition v. compression that exceeds marketable condition) is another active issue area.

4. Beyond the general language of the mineral leasing statutes, does the Mineral Management Service offer any other guidance?

The OCS Lands Act and the Mineral Leasing Act authorize the Secretary of the Interior to issue leases and collect royalties based on the value of production but neither prescribe the details of royalty calculations. Minerals Management Service complements the general language of the mineral leasing statutes in several ways. In addition to its regulations at Title 30 of the Code of Federal Regulations, it also offers guidance. **For all payors, the MMS publishes a "Minerals Revenue Handbook" and an "Oil Gas Payor Reporter Handbook" of general applicability and,**

after major regulatory events, holds public training workshops for anyone interested. For similarly situated payors dealing with special issues, it issues "Dear Payor" letters. For individual payors with atypical situations, the MMS also offers royalty valuation determinations or future valuation agreements consistent with existing regulations.

5. How are royalties calculated?

For any production royalties are usually calculated by taking the production volume (barrels of crude oil, MCF of gas) then multiplying it by the royalty rate. Volumes are measured by using very precise equipment subject to carefully developed measurement standards. Royalty rates are usually 1/8th (12_ %) the value of production for onshore production and 1/6th (16 2/3) for federal offshore production on the Outer Continental Shelf (OCS).

6. Can royalty rates be adjusted?

Effective royalty rates can vary from the usual royalty rates for several reasons. The Secretary of the Interior has always had the discretion to adjust royalty rates. One obvious scenario is where the reservoir is reaching the end of its useful life and reservoir economics would require shut-in (e.g. after which no production would occur and zero royalties would be generated) without royalty relief. As amended in 1978, the OCS Lands Act also authorizes the Secretary to use a variety of approaches other than a straight percentage (e.g., net profit sharing) to encourage OCS lease sale bidding.

The 1995 Deep Water Royalty Relief Act and certain provisions of the Energy Policy Act of 2005 specifically address royalty relief for certain types of leases, recognizing that ever deeper exploration and production regimes involve technological challenges and extraordinary production and post-production costs that seriously affect the economics of production. Most recently, the Secretary has begun to explore royalty relief for shallow water deep gas, a production scenario that did not exist before the advanced exploration and production technological advances of recent years. Where deep water and deep gas royalty relief applies, the royalty rate is zero, but once MMS-prescribed "suspension volumes" and, in some cases, market price thresholds are exceeded, the royalty rate reverts to its nominal rate, usually 12 _ %.

7. Do cash payments represent the only method of satisfying the royalty obligation?

No. Although the mineral leasing statutes have always allowed royalty-in-kind (RIK), in recent years the MMS has been taking an increasing amount of its royalties in kind. In the mid-90s, with healthy skepticism the MMS undertook a series of pilot projects which evolved into a full-fledged RIK program recognized by the 2005 Energy Policy Act and subject to stringent performance criteria to assure that RIK revenues do not yield less than royalty-in value revenues. RIK offers a very high level of transparency because it averts the need to determine the "value of production, which can be difficult for non-arm's length transactions. However, RIK transactions are still subject to audit (with a sharp focus on volumes), and also gives the MMS an opportunity to enhance its royalty revenues by collecting for itself any marketing profit that would otherwise be taken by industry.

8. Why are allowances for transportation and processing deducted from the selling price of oil and gas production before royalties are calculated?

Under well-established oil and gas law in place for decades, and reflected in federal leasing statutes, leases and regulations, royalty is due on the "value of production," a wellhead concept. Where the production is sold at or near the wellhead, the proceeds from the sale are a good measure of the value of production. Where sales occur downstream of the wellhead, increasingly common since deregulation of gas, the gas must be moved and processing may be required. Transportation and processing are operations that must be paid for, the operations are post-production in nature, and the value they generate must be deducted to arrive at the true value of production. Under MMS regulations "allowances" are the vehicle for making these deductions. While disputes may arise on the specific calculation of allowances, there is no question that allowances are lawful and appropriate.

9. Do royalties comprise all of the mineral revenues reported by the Minerals Management Service?

No. Royalty revenues account for the bulk of the revenues reported but revenues also include: (non-refundable) bonus bids paid by companies to obtain OCS leases, explore for oil and gas and hopefully produce oil and gas; rentals, paid until production in paying quantities occurs; and RIK revenues. Onshore leasing is somewhat different than OCS leasing, but can include competitive bidding and does include rentals before production in paying quantities occur.

10. What is the typical breakdown of federal oil and gas royalties[js1]**?**

Federal oil and gas royalties are generated from production on about 24,000 onshore leases and about 2000 OCS leases. Shown below is a typical breakdown based on figures reported by the MMS:

Federal Oil & Gas Royalty Revenues for Fiscal Year 2005

	Oil	Gas	Oil & Gas
Federal Onshore Leases	**$.398 billion**	**$1.65 billion**	**$1.5 billion (22%)**
Federal Offshore Leases	**$2.12 billion**	**$3.25 billion**	**$5.37 billion (78%)**
Total	**$ 2.52 billion (37%)**	**$4.9 billion (73%)**	**$6.87 billion (100%)**

Notes
1. Indian leases not included.
2. Gas totals do not include natural gas liquids.
3. Royalty totals do not include bonuses (accounting for about 13% of total revenues) and rentals (about 3% of total revenues).

Oil and gas development also occurs on Indian lands and generates royalties but accounts for a relatively small percentage of the whole.

11. What percentage of the nation's oil and gas is produced on federal lands?

Overall, the US imports about 60% of its crude oil supply and about 16% of its gas supply. Production on federal lands accounts for about 33% of the domestic oil production total and about 38% of the domestic gas total. Federal land oil and gas production relative to other domestic production has risen sharply since 1980 and that trend is expected to continue because energy demand continues to grow and frontier areas, where most new oil and gas is located, are mostly federal lands. However, many federal lands are not open for oil and gas exploration or development because of environmental or other restrictions.

About 2000 federal offshore leases account for about 75% of the federal oil production and about 25% of the gas production; about 24,000 federal onshore leases make up the remaining oil and gas volumes.

12. Who are the beneficiaries of royalties generated by production on federal lands?

The US Treasury is the principal beneficiary of federal oil and gas royalties with large sums earmarked for certain funds (e.g., Historic Preservation Fund, Land & Water Conservation Fund, Reclamation Fund). However, where the oil or gas is produced on onshore federal lands within a particular state, that state is entitled to 50% of the royalties. Where federal offshore production occurs close to the seaward boundary of coastal states, those states are entitled to a 27% share of royalty revenues.

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