FORENSIC MINERAL AUDITING FOR ROYALTY OWNERS

Shannon Springs, LLC

Mineral interest audits for trustees, CPAs, family offices, estate attorneys, and mineral owners

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FORENSIC AUDIT · ADVANCED TECHNOLOGY

Horizontal Drilling and the Forensic Audit Gap

Modern extraction technology doesn't create new types of royalty errors. It multiplies the existing ones — across larger units, higher production volumes, and allocation decisions that royalty owners have almost no visibility into.

By Mark E. Grigsby — Shannon Springs, LLC — June 2026

The horizontal drilling revolution transformed the economics of American energy production. It also transformed the economics of royalty underpayment. Every forensic audit issue that existed before horizontal drilling still exists. What horizontal drilling did was change the scale: larger units, far higher production volumes, more complex allocation methodologies, and a dramatically higher dollar value attached to every percentage point of error.

> *Horizontal drilling didn't create new types of errors. It multiplied the existing ones by an order of magnitude.*

The Scale Problem: Why the Math Changes

Well Type	Typical Unit	NRI (10 NMA, 1/5th royalty)	Est. Peak Production	Owner's Est. Peak Monthly
Conventional vertical	160 acres	0.01250	50 BOE/day	~$375/mo.
Horizontal (single section)	640 acres	0.003125	500 BOE/day	~$3,750/mo.
Horizontal (extended lateral)	1,280 acres	0.001563	1,000 BOE/day	~$7,500/mo.

Assumptions: $50/BOE equivalent, 1/5th royalty. For illustration only. A 10% underpayment on the extended lateral = $750/month; over a 24-month lookback, ~$18,000 in recoverable royalties from a single well.

Six Specific Audit Issues That Horizontal Drilling Amplifies

ISSUE 01
Cross-Unit Wellbore Allocation

Laterals extend 2–3 miles, sometimes exceeding 5 miles, crossing multiple units. The operator's allocation methodology is rarely disclosed and almost never independently verified.

ISSUE 02
Multi-Zone Commingling

Multiple formations produced through one wellbore; each zone may have different owners and royalty rates. Commingling allocation is almost never reviewed by the royalty owner.

ISSUE 03
Post-Production Cost Exposure

NGL-rich shale wells generate higher gathering, compression, and processing costs. More cost exposure = more opportunity for improper deductions under a marketable condition lease.

ISSUE 04
Peak Production Underreporting

Horizontal wells produce peak volume in months 1–24, then decline steeply. Early production understatement forfeits the highest-value period; the clock starts immediately.

ISSUE 05
NGL Affiliate Pricing

NGL-rich shale wells produce large volumes of each component priced separately. Affiliate-sale pricing at below-market rates is one of the largest single underpayment sources.

ISSUE 06
Depth Severance and Formation Control

Without a depth severance clause, an operator can hold all of your formations via production from just one, preventing independent development of deeper interests for decades.

Cross-Unit Wellbore Allocation: Verifiability by Method

Allocation Method	How It Works	Independently Verifiable?	Owner Risk
Lateral length	Proportional to wellbore length in each unit	Yes — via directional survey records at OCC/RRC	Moderate
Perforated interval	Based on perforation and fracture locations	Partially — requires completion report analysis	Moderate
Proprietary model	Internal reservoir engineering, not disclosed	No — requires audit demand or litigation	High

THE AUDIT GAP

When an operator uses a proprietary allocation model, a reconciliation platform has nothing to compare it against. The only way to surface the issue is to cross-reference reported unit-level production against the directional survey and OCC/RRC completion data — neither of which appears in an operator-reported dashboard.

Emerging Technologies: New Frontiers, Same Starting Point

Several technologies now moving into commercial production raise new subsurface rights questions. In each case, the answer begins with reading the existing lease carefully — language written years or decades ago, without contemplating the activities now being deployed.

Technology	The Mineral Rights Question	Current Status
CO_2 Sequestration (CCUS)	Who owns subsurface pore space — surface owner or mineral owner? Does existing lease convey storage rights?	Unsettled in most producing states; active legislation in OK, TX, WY
Underground Gas Storage	Can operator use depleted reservoir for storage without mineral owner's consent or compensation?	State-by-state; most legacy leases are silent on storage
Blue Hydrogen	Is royalty on gas at the wellhead or on the derived hydrogen? Are conversion costs deductible under the lease?	Emerging; no established royalty calculation standard
Geothermal	Does an existing oil and gas lease cover geothermal activity? Do depth severance clauses apply?	Active litigation in OK and TX; legislation varies by state
Helium Extraction	Is helium covered by the oil and gas lease? Most operators treat helium revenue as their own.	TX Panhandle, KS, CO have commercial helium; most leases silent
Lithium / Critical Minerals from Produced Water	Is produced-water mineral recovery a royalty-bearing stream or operator income?	Arkansas addressing bromine/lithium specifically; most states have not
Direct Air Capture (DAC)	DAC competes with the subsurface for pore space without producing anything, creating new title conflicts.	Early commercial stage; pore-space title disputes expected to increase

> **THE COMMON THREAD**
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> Every emerging technology that touches the subsurface starts with the same document: your lease. What the operator can do with your vertical column — which formations they can hold, which resources they can extract, and whether byproduct revenue streams (helium, lithium, CO_2 storage) carry a royalty obligation — is determined by language written years or decades ago, often without contemplating the technologies now being deployed.

Priority Actions for Mineral Owners and Trustees

Action	Why It Matters	Priority
Obtain directional survey and completion reports	Basis for challenging cross-unit allocation if operator model is proprietary	High
Audit all horizontal division order decimals	Smaller, more complex decimals; proportionally higher dollar impact per error	High
Cross-reference operator volume against OCC/RRC unit production	Early production understatement is the highest-dollar recoverable error	High
Audit NGL component pricing against Mont Belviëu indices	Affiliate pricing on high-volume NGL streams is a common, significant underpayment	High
Review commingling agreements for multi-zone wells	Allocation methodology determines what each zone's owner is paid	Medium
Review lease language for depth severance and CCUS applicability	Determines operator rights to hold deep formations and new-technology activities	Medium
Monitor OCC/RRC for new horizontal pooling applications	Election deadlines carry far higher financial consequences on horizontal wells	High — ongoing