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Rekindling the Flame: Oil and Gas Securitizations

By Kimberlee Cagle, Susan O. Berry, Carol Burke, Kathryn Weiss, and Michael L. Urschel*

This article describes certain structured finance products (e.g., volumetric production payments, future flow securitization of interests that are carved out of the working interests, and future flow securitization of non-operating working interests) for the U.S. oil and gas industry and sets forth certain issues to consider in connection with a potential investment in those products.

A number of recent structurings of investment-grade rated securitizations of oil and gas wells are sparking conversations in the U.S. upstream oil and gas industry about this relatively new structured finance product. Although structured finance products are not new to the industry, interest in these products has been rekindled as exploration and production ("E&P") companies seek alternatives to the more traditional reserve-based loans, equity financing, and bond issuances. Indeed, last year Fitch Ratings ("Fitch") predicted that oil and gas companies may tap the securitization market with rated securitizations backed by proved developed and producing ("PDP") reserves. Fitch also announced that it had enhanced its framework for rating oil and gas royalties securitizations.[1]

This article describes certain structured finance products (e.g., volumetric production payments, future flow securitization of interests that are carved out of the working interests, and future flow securitization of non-operating working interests) for the U.S. oil and gas industry and sets forth certain issues to consider in connection with a potential investment in those products.[2]

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[1] *See* Future Flow Securitization Rating Criteria, Appendix C, Fitch Ratings (July 3, 2019).

[2] Federal income tax considerations, such as the income tax treatment of production payments carved out of mineral property, will not be discussed in this article.

An oil and gas securitization is an alternative financing structure that produces a security ("Notes") whose income payments come from and are collateralized by a certain pool of underlying assets. Although such underlying assets are often unable to be sold individually, pooling those assets into a single investment ("securitization") renders them more attractive to investors, in part by diversifying the risk of investing in the underlying assets. Unlike a typical financial product securitization, oil and gas securitizations, which are a form of future flow securitizations, are backed by receivables that do not currently exist, so repayment of the Notes relies upon the originator continuously generating receivables.[3] Securitization of such future-flow royalties outside of the oil and gas industry include film royalties, music royalties, drug royalties and whole business securitizations of businesses that rely on a franchise model to generate royalties (such as restaurant businesses).

TERMINOLOGY OF CERTAIN OIL AND GAS INTERESTS

In the United States, interests in oil and gas under the surface of the land are real property interests that belong to a mineral interest owner, which may be the federal government, a state government, or a private party. The mineral interest owner, as lessor, may enter into an oil and gas lease with a counterparty, as lessee, whereby the lessee is granted the right to explore, drill and produce oil and gas from the property.

Royalty Interest

The lessor typically reserves a "royalty interest" in oil and gas production from the lease. A royalty interest is free of the costs of production and is often expressed as a fraction, such as 1/8th (12.5 percent).[4] The lessee pays the lessor a monetary amount determined with reference to the gross production, typically based on revenue received by the lessee, although royalties may be paid "in kind" (i.e., the royalty holder is entitled to receive their percentage share of the oil or gas itself).

Working Interest

In contrast, a "working interest" (or "WI") is the percentage of ownership in an oil and gas lease that grants its owner the right to explore, drill and produce from a tract of property. The owners of the working interest are required to pay a corresponding percentage of the costs of exploration, drilling and production operations of a well or unit. A working interest owner is also entitled to receive its share of production based upon its percentage working interest after royalties

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[3] *See* Future Flow Securitization Rating Criteria, *supra* note 1, at 2.

[4] Whether post-production costs may be deducted from a royalty payment is beyond the scope of this article.

are paid. For example, if an E&P company owns a 100 percent working interest in a lease burdened by a 1/8th royalty held by the landowner, the E&P company would bear 100 percent of the costs of a well and share in 87.5 percent of the production from that well.

Working interests may be of two types: operated and non-operated. The working interest owner that is the "operator" manages the exploration and production operations, including proposing wells, supervising drilling, and handling marketing and accounting functions. The operator and the non-operating working interest owners will usually enter into a joint operating agreement ("JOA") that sets forth the parties' agreement about exploration, drilling, development, operations, and accounting of the oil and gas properties in which they have joint interests. As noted above, unlike royalty interests, working interests bear the costs of operating a well or unit in return for a share of revenue, so the oil and gas industry has an accounting system called "joint interest billing" that divides the revenues and costs of operations among the interest owners. The operator will calculate which costs are chargeable to the non-operators under the JOA, allocate those costs based upon their respective working interests and send out joint interest billing statements ("JIBs").

In addition to issuing JIBs, before commencing drilling or subsequent operations (such as completion or plugging and abandoning a well) the operator will prepare and distribute an authority for expenditure ("AFE"). An AFE is a cost estimate by category for the proposed drilling project or subsequent operation and may be accompanied by a projected payout schedule or revenue forecast.

Net Revenue Interest

A working interest owner's net revenue interest ("NRI") is its share of oil or gas production after deduction of all burdens, such as royalties and overriding royalties, as described below.

Overriding Royalty Interest

A royalty carved out of the net revenue interest associated with the working interest is known as an "overriding royalty interest" (a/k/a "override" or "ORRI"). An ORRI is a fractional interest in the right to receive the proceeds from the sale of production without paying development or operating costs. It typically terminates when the underlying lease terminates. An ORRI will frequently bear its share of post-production expenses, but not any portion of the capital expenditures necessary to drill and complete the well.

Net Profits Interest

A net profits interest ("NPI") may also be created out of the working interest. The owner of an NPI is entitled to a share of production or production revenues from the operations of the subject lease free of the costs of production to the extent there is a net profit. An NPI interest differs from an ORRI mainly by inclusion of the capital costs necessary to drill the well in the overall net profits interest calculation, so that the NPI holder does not receive its share of net profits until the WI holder recovers its share of those costs, along with post-production expenses and potentially certain other negotiated expenses. If there is no net profit, the NPI owner does not receive any revenue. The method of calculating net profits must be set forth in the agreement between the parties because there is no generally accepted method of calculation. State law determines whether an NPI is considered to be a personal property interest or a real property interest.

Production Payment Interest

A production payment is the right to receive production, or the proceeds of production, until the total amount of production volume or revenue is reached as agreed by the parties in their contract. A production payment is free of the costs of production. State law determines whether the production payment is an interest in real property or personal property.[5] The U.S. Bankruptcy Code defines a production payment as "a term overriding royalty satisfiable in cash or in kind—(A) contingent on the production of a liquid or gaseous hydrocarbon from particular real property; and (B) from a specified volume, or a specified value, from the liquid or gaseous hydrocarbon produced from such property, and determined without regard to production costs."[6] If a production payment covers a fixed quantity of hydrocarbons from the specified oil and gas leases, it is a "volumetric production payment" or "VPP," and if it covers a fixed amount of proceeds from the sale of hydrocarbons from such leases, it is a "dollar-denominated production payment."

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[5] Texas and Wyoming courts, for example, have held that production payments are interests in real property. *See e.g. Sheppard v. Stanolind Oil & Gas Co.,* 125 S.W.2d 643, 647 (Tex. App.—Austin 1939, writ ref'd) (holding that a lease bonus payment paid as a percentage of production is a real property interest because it constitutes a part of the purchase price of the title to the oil and therefore of the land) (citing *Tex. v. Hatcher*, 281 S.W. 192 (Tex. [Comm'n Op.] 1926)); and *EOG Res. Inc. v. Dep't of Revenue*, 86 P.3d 1280, 1282–83 (Wyo. 2004) (in a severance and ad valorem tax case involving a volumetric production payment between EOG and one of the Cactus entities (see discussion of Cactus), the court stated that the buyer's production payment interest is a real property interest).

On the other hand, the Kansas Supreme Court held, in a statute of frauds case involving an oral agreement for the sale of an interest in an oil and gas lease in which the consideration was cash and 20,000 barrels of oil out of any oil produced from the land described in the lease, that the agreement was one relating to personal property. *See McCrae v. Bradley Oil Co.,* 84 P.2d 866, 870 (Kan. 1938).

[6] 11 U.S.C. § 101(42(A)).

VOLUMETRIC PRODUCTION PAYMENT ("VPP") FINANCINGS

Overview

In a VPP financing, the financing provider ("VPP Purchaser") (such as a bank or private equity firm, either directly or through a special purpose entity ("SPE")) provides funds upfront to the producer[7] by purchasing from it a volumetric production payment that is a non-operating, non-expense bearing overriding royalty interest which is carved out of specified oil and gas producing leasehold interests owned by the seller ("Specified Properties"). Instead of cash, the VPP entitles the VPP Purchaser to a designated share of the hydrocarbons produced from the Specified Properties over the stated term. Contemporaneously with entering into the agreement with the producer, the VPP Purchaser will generally monetize the production by entering into a forward sales contract to pre-sell the hydrocarbons at a set price (such as the spot price or a price based on forward prices for the hydrocarbon). The VPP Purchaser will also generally hedge its hydrocarbon price risk by entering into derivative transactions such as commodity swaps.

Reservoir/Production Risk

The VPP Purchaser's recourse is limited to production from the Specified Properties, and the VPP Purchaser has no right to additional production unless there is a shortfall from a prior period. The VPP Purchaser cannot look to the producer's other assets, including its revenues from operations, to support any shortfall. The VPP Purchaser may want to mitigate these risks by diversifying the properties included in the VPP.

Lack of Upside Potential

Because a VPP is limited to a specified volume of production over a stated term, the VPP Purchaser does not share in any excess production nor does it share in any production after the VPP terminates. Further, the VPP Purchaser does not share in any appreciation of the underlying Specified Properties. As such, producers may desire to finance their longer-lived properties with a VPP because the producer can retain the production after the VPP terminates.

Operational and Environmental Risks

A VPP is not a working interest, so the VPP Purchaser has no right to explore, drill, produce, or otherwise operate the Specified Properties. The operational risks remain with the producer. The VPP documentation will include covenants of the producer as to operating, developing, and maintaining

[7] For simplification, this article assumes that the producer is the E&P company which is the operator of the oil and gas properties and the seller of the VPP.

the Specified Properties, but the VPP Purchaser may also want to engage an outside hydrocarbon asset operating engineering firm to assist in the due diligence. In addition, although the producer agrees to indemnify the VPP Purchaser, the hedge providers and the investors for environmental liabilities attributable to the Specified Properties, the VPP Purchaser may want to engage an environmental consultant as well. The VPP Purchaser will need to be satisfied with its due diligence on the producer and the underlying oil and gas properties and structure the VPP so that the producer has the incentive to continue production on the Specified Properties (for example, by setting the tenor and amount of the VPP such that there is sufficient value in the Specified Properties after the VPP ends). The VPP Purchaser also bears the risk that, during a drop in the price of oil or gas, the producer may determine that it is uneconomical to produce and cease production from some or all of the Specified Properties.

Safe Harbor in Bankruptcy

In the event that the producer/seller of the VPP files for bankruptcy, the U.S. Bankruptcy Code provides a safe harbor for production payments (as defined in the U.S. Bankruptcy Code; see above). Property of the bankrupt debtor's estate does not include "any interest of the debtor in liquid or gaseous hydrocarbons to the extent that . . . (i) the debtor has transferred such interest pursuant to a written conveyance of a production payment to an entity that does not participate in the operation of the property from which such production payment is transferred; and (ii) but for the operation of this paragraph, the estate could include the interest referred to in clause (i) only by virtue of section 365 or 542 of this title."[8]

If a VPP does not fall under the Section 541(b) safe harbor, then the VPP may still be excluded from the debtor's estate under Section 541(a) of the U.S. Bankruptcy Code to the extent that the conveyance of the VPP prior to the commencement the bankruptcy case was a true conveyance by the debtor of an interest in real property under the laws of the state in which the underlying properties are located. Consideration should be given as to whether the state law considers a term overriding royalty interest to be personal property or whether state law is unclear or inconsistent as to classifying mineral and lease interests. In those cases, there is a risk that the VPP hydrocarbons may be included as property of the estate and subject the underlying oil and gas leases and the VPP transaction to rejection in bankruptcy. VPPs may also be subject to recharacterization as a "disguised financing" which is discussed below.

[8] 11 U.S.C. § 541(b)(4)(B). Section 365 of the U.S. Bankruptcy Code concerns executory contracts and unexpired leases, and Section 542 concerns turnover of property to the estate.

Securitization of VPPs

Securitizations of VPPs are not new. Enron Corp. began its VPP program in 1990, using SPEs to ring-fence the producers' production fields underlying the VPPs.[9] In order to securitize its VPP program, Enron then developed a structured finance program using a series of limited partnerships known as the "Cactus Funds." The SPE limited partnerships would acquire a pool of VPPs and typically issue Class A units and Class B units to investors. Another SPE would be formed to purchase the Class A units using proceeds from bank loans.[10]

SECURITIZATION OF INTERESTS THAT ARE CARVED OUT OF THE WORKING INTERESTS

Overview

In addition to VPPs, other types of interests that are carved out of the working interest may be securitized. The interests may include a royalty, an ORRI, a "net" ORRI or an NPI. One structure that is used is an SPE known as a royalty trust. The sponsor E&P company forms a trust under state law and conveys the interests to the trust. To fund the purchase of such interests, the trust issues units which are sold to investors. The trustee collects the net proceeds attributable to the interests, pays expenses and charges of the trust, and distributes the remaining income to the unitholders, often on a monthly or quarterly basis. Some royalty trusts are publicly traded and have been in existence for many years, such as the Permian Basin Royalty Trust which was created in 1980.

Tenor of a Royalty Trust

The trust indenture may provide that the trust terminates at a specific time (or after a specific amount of hydrocarbons have been produced) or when the reserves underlying the royalty interests are basically exhausted (e.g., the trust's net revenues are less than $1 million a year for two consecutive years). In either case, because the trust is not investing in additional royalties from new oil and gas properties, the trust assets are depleting over time as the underlying reserves are depleted and production declines.

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[9] *See* Christopher L. Culp & Barbara T. Kavanagh, Structured Commodity Finance after Enron Uses and Abuses of Prepaid Forwards and Swaps, in CORPORATE AFTERSHOCK: THE PUBLIC POLICY LESSONS FROM THE COLLAPSE OF ENRON AND OTHER MAJOR CORPORATIONS loc. 2627-32 (Christopher L. Culp & William A. Niskanen, eds., 2003) (ebook).

[10] *Id.* at loc. 2638-49.

Types of Reserves

In contrast to a VPP which typically is based only on producing wells on PDP properties, a royalty trust may include royalties attributable to wells to be drilled on proved undeveloped reserves ("PUDs") or even proved developed non-producing ("PDNP") reserves. This provides investors with the potential for more upside if the new wells are successfully drilled and completed and have good production, but conversely there is increased production risk. Fitch, in its Future Flow Securitization Rating Criteria, states that investment-grade ratings are "only achievable when the transaction is backed by PDP (Proven Developed Producing) reserves and cash flows are expected to be sustained without significant development capex."[11]

Factors Affecting Revenues/Profits

A drop in oil or gas prices could cause the amount of revenues to decline, so to mitigate this risk, the sponsor may choose to enter into a hedging contract which it then conveys to the trust. If the underlying properties have low production, then revenues may also decline. If the interest is cost-bearing, such as an NPI or a net ORRI, then increased production costs may also decrease the amount of income attributable to such interests.

Bankruptcy

Similar to a VPP, if the interest does not fall within the U.S. Bankruptcy Code's safe harbor for a production payment, state law must be considered to determine how the interest is characterized. NPIs in particular may be construed not as a real property interest that was conveyed prior to bankruptcy (and therefore not property of the debtor's estate), but rather as a contractual right to the proceeds of production and thus a personal property interest. Even though a transaction appears to fall within the U.S. Bankruptcy Code's definition of a production payment, Section 541(b)(4)(B) requires that there be a "transfer" of an interest by the debtor. If the terms of the conveyance have debt-like features, there is a risk that the bankruptcy court may recharacterize the transaction as a loan rather than a transfer of interest in real property (i.e., a "disguised financing"), and thus the interest remains property of the bankrupt debtor's estate.

Although not a securitization transaction, in the ATP Oil & Gas Corporation ("ATP") bankruptcy, the bankruptcy court found that there was a genuine issue of material facts as to whether the conveyance by ATP to NGP Capital Resources Company ("NGP") of certain ORRIs were interests that were

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[11] *See* Future Flow Securitization Rating Criteria, *supra* note 1, at 19.

consistent with a term ORRI under Louisiana law.[12] As a result of the *NGP v. ATP* ruling, precautionary mortgages are typically filed so that if a conveyance were to be recharacterized as a loan, the loan would be secured by the ORRI.

SECURITIZATION OF WORKING INTERESTS

Overview

As mentioned previously, securitizations are not entirely new to the oil and gas industry, although there is now a resurgence in interest in such investments, particularly as they concern working interests (as defined above).

In a securitization of working interests, like any other securitization, the underlying assets are identified (such as working interests in PDP wellbores[13] owned by a specific E&P company) for transfer into a bankruptcy-remote SPE owned by the company or an affiliate. The SPE "pays for" the PDP assets by selling Notes to investors, through a private placement or other offering, and transferring the cash proceeds of the sale to the E&P company. The SPE offers the investors security for those Notes by pledging the PDP assets as collateral for the benefit of the secured party, often a trustee for the benefit of the investors. The Notes are rated by an independent ratings agency, which evaluates the risk and therefore drives the price of the Notes.

As with other investments in oil and gas properties in which investors typically require a specialized operator of the assets, in a securitization of working interests, the E&P company (or its affiliate) is tasked with managing the assets pursuant to a servicing or management agreement. There should also be a backup servicer who can step in to manage the assets in the event certain defaults by the E&P company occur. Revenues of production are distributed pursuant to a "waterfall" which will provide the order of such distributions for obligations such as payment of the costs of the SPE (including servicing fees and backup servicing fees), the debt service on the Notes[14] and the funding of reserve accounts (if not fully funded at closing), with the owner of the equity interest in the SPE (or other holder of the residual interest) receiving payments at the bottom of the waterfall.

Working Interests as Cost-Bearing Interests

Reserve accounts are generally established as part of a securitization structure to ensure that funds are available to make certain payments as they become due.

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[12] *See In re ATP Oil & Gas Corp.*, No. 12-36187ADV 12-03443 (Bankr. S.D. Tex. Jan. 6, 2014).

[13] A wellbore is the drilled hole that forms the oil and gas well.

[14] If there are tranches of debt, then the waterfall will also address the order of payment among the tranches.

Payments for which funds may be reserved include interest payments on the Notes (e.g., reserve an amount that would service at least three to six months of interest) and other essential expenses and payments (such as servicing fees or back-up servicing fees) if certain events occur. Importantly, in addition to these typical types of reserves, the structure and documentation for a securitization of working interests must also cover payment of operating expenses and maintenance capital expenditures—after all, these are cost-bearing interests. Unlike a non-working interest investment, the SPE in a working interest securitization is responsible for its proportionate share of the costs of exploration, drilling, and production operations, including obligations such as JIBs, potential secondary plugging and abandonment liability and potential secondary environmental costs. For these reasons, the reserve accounts and their methods of replenishment should be closely scrutinized, as should the PDP assets actually selected for the securitized pool.

As to the latter point, the subject properties chosen for the pool should be evaluated so as to quantify risks and consider key legal structuring points. Factors to consider include whether the PDP assets sit in conventional or unconventional plays and have a consistent "track record" of runs, any transfer restrictions or preferential purchase rights and any liens or mortgages to which they may be subject, existing environmental issues, and where they are in their working life as a predictor of likely workover costs.[15] As in a VPP, due diligence on the underlying properties is required.

Securitization of Working Interests vs. VPP

Conversation around recent transactions has logically stimulated comparisons between VPPs and securitization of working interests and their respective risks and benefits to investors.[16] The securitized working interest structure is currently seeing support for the following reasons, among others:

- *Collateral and Cash Flow*: As noted, in a VPP transaction, only a certain volume of production serves as collateral, and additional cash flow from excess production is paid to the producer.

  Unfortunately, if there is an underperformance in production, there is no cash earmarked to bolster the VPP. In contrast, in a working interest securitization, all of the ownership of production serves as

[15] A workover involves the repair of an existing well. Workover costs may be incurred for many reasons, such as repairing downhole equipment, removing sand from the wellbore or stimulating production from the well.

[16] In addition, logical comparisons of the risks and benefits of a securitization of working interests have been made to those of reserve-based loans, but that analysis is outside the scope of this article.

collateral (including the working interest owner's NRI which is not capped) and cash flows through the SPE and its waterfall. Covenants in the securitization documentation can require that excess cash flowing through be used for accelerated amortization or moved into a cash trapping/sweep account if certain production metrics are not being met.

- *Interest Protections*: The previously mentioned interest reserve in the securitization structure protects investors from certain liquidity shortfalls, as three to six months of interest payments may be funded to a reserve account backstopping otherwise unfunded interest payments for some period of time. A VPP does not have such interest reserve protection.
- *Common Incentives Between Owners and Investors*: Both the E&P company and investors in the Notes stand to benefit from the same outcome in the working interest securitization. For instance, if there are stressors on production (such as a drop in the commodity price), in a securitization the cash can be retained by the SPE. Conversely, in a VPP if the commodity price suffers rendering production uneconomical, the E&P company may curtail or cease production altogether. In a VPP the producer is paid up-front for the volumes, while in a securitization, the E&P company may not receive cash until payment on the Notes helping ensure alignment of interests.
- *Maturity*: As discussed above, in a VPP the producer retains the production after the VPP terminates. Consequently, the tenor and amount of a VPP are set so that the post-VPP value of the Specified Properties is sufficient to incentivize the producer to continue production during the VPP in the face of production stressors. While there may be a period after the stated term in which the producer may make up for shortfalls in production, that period is typically a few months thus increasing the risk that a shortfall remains. In contrast, the legal final maturity of the working interest securitization may be substantially longer thereby providing the investors more time to recover principal on the Notes.
- *Bankruptcy*: In the context of bankruptcy risks, a working interest securitization may be preferred to a VPP that does not fall within the production payment safeharbor.

On the other hand, there are some less favorable aspects of a working interest securitization as compared to a VPP, specifically:

- *Hedges for Downside*: To ensure predictable cash flows to investors, securitization structures for working interests will require hedging a high percentage of production at long terms (at least four years and up to the expected maturity date of up to 10 years). This is an expensive endeavor.

- *Transaction Time*: A working interest securitization structure should be expected to take more time and come at a higher structuring cost because of the rating process and given the complexity and number of parties. However, although a working interest securitization may demand more legal costs upfront versus more traditional methods of monetization, the tenor of the transaction is longer than a VPP and thus could be expected to benefit the E&P company and the investors for a longer period.

The financial market's rekindled interest in non-traditional assets for future flow securitizations may well introduce an abundance of new investors, such as insurance and pension companies, to E&P companies when the industry much needs new capital during this challenging period.