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Colorado Supreme Court Clarifies the Law Applicable to Oil and Gas Leases

By Diana S. Prulhiere and David R. Little, Steptoe & Johnson PLLC

The Colorado Supreme Court announced its long-awaited decision on the universal application of the "commercial discovery rule" to Colorado oil and gas leases on November 20, 2023. The announcement stems from *Board of County Commissioners of Boulder County v. Crestone Peak Resources Operating LLC* (2023 CO 58, 2023 Colo. LEXIS 1086, 538 P.3d 745, 2023 WL 8010221).

In 2021, a panel of the Colorado Court of Appeals held that an oil and gas lease in Colorado only terminates in its secondary term under a cessation of production clause if wells on leased or pooled lands are incapable of producing oil and gas in commercial quantities. The panel also rejected arguments that cessation of production clauses are triggered whenever production ceases from leased or pooled lands during the secondary term regardless of whether such cessation is temporary or permanent.

The Colorado Supreme Court reversed. Rejecting application of any universal definition of the word "production" (such as the commercial discovery rule), the Supreme Court held that "each oil and gas lease" in Colorado should be interpreted "on its own terms" and the goal of parties and the courts should be to "determine the parties' meaning within the context of the lease."

Among the many other important observations of the Supreme Court are the following:

- Oil and gas leases are different from other Colorado contracts because they are both a conveyance and a contract;
- In Colorado, it is the intent of the original parties to an oil and gas lease that matters, and intent should ordinarily be gleaned from the language used in the lease as well as the expressed purpose of the lease and the terms and remedies chosen by the original parties;
- The nature of the primary term of an oil and gas lease differs in many respects from that of the secondary term, and the standard for determining whether sufficient production has been achieved during the secondary term may differ as well;
- To avoid unduly depriving lessees of their investment, courts should exercise greater caution when assessing and determining whether an oil and gas lease has terminated during its secondary term due to a cessation of production;
- Although the commercial discovery rule may aptly reflect the intentions of the parties to some oil and gas leases, it is unnecessary and unwise to universally impose its definition of production in every oil and gas lease, regardless of the context and the other provisions chosen by the parties;
- Cessation of production clauses are savings clauses intended to extend, and not restrict, a lessee's rights during the secondary term, and may or may not eliminate or avoid the operation of the common law temporary cessation doctrine; and
- Shut-in royalty clauses are savings clauses that should be given meaning and not rendered superfluous through an interpretation of a cessation of production or other lease clauses.

The Other, *Other* Two-Step: Dancing Around Transfer Restrictions in A&D Transactions Using Divisive Mergers

By Buddy Clark, Ellen Conley, Austin Elam and Farhad Tahir, Haynes and Boone, LLP

The current optimism for increased deal activity in 2024 has upstream and midstream companies reevaluating their portfolios and strategy for the year ahead. As has been common in the industry, many asset packages contain properties and rights that are subject to contractual restrictions on their transfer. In certain circumstances, however, companies may employ a corporate dance (or two) to streamline transactions, with the added benefit of potentially avoiding those restrictions, customarily in the form of preferential rights to purchase and required consents, triggered by the sale of assets.

The "Texas Two-Step" is a familiar dance move in Texas honky-tonks. In the context of oil and gas acquisitions and divestitures, it is a moniker for a technique that traditionally involves a two-step process, with a seller first forming a wholly-owned subsidiary and then transferring the applicable assets to the new subsidiary. Because dispositions to an affiliate are typically exempt from transfer restrictions, and this first step involves an assignment to a subsidiary (and not a third party), restrictions on transfer are not often applicable. Under the second step, the seller sells its equity interests in the subsidiary to a third-party buyer. Because the equity sale does not constitute an assignment of the assets directly, courts in many oil and gas producing regions have found that restrictions on direct transfer are not triggered.

While Texas law has found that these direct transfer restrictions can be avoided under the traditional Texas Two-Step, other states look for evidence that the parties' dance steps were not solely chosen for the purpose of avoiding the restrictions. For example, a Louisiana appellate court in *Fina Oil and Chem. Co. v. Amoco Prod. Co.*, 673 So. 2d 668 (La. App. 1st Cir. 1996), writ denied, 679 So. 2d 1353 (La. 1996), followed the Texas position and allowed a structure that avoided the application of a preferential right to purchase. The case, however, noted that the structure was not used to deliberately circumvent the preferential right. Additionally, in *Citgo Petroleum Corp. v. Occidental Chem. Corp.*, 29 F. App'x. 525 (10th Cir. 2002), the Tenth Circuit, applying Louisiana law, upheld a two-step transaction stating that the terms of the preferential right to purchase were clear, unambiguous, and negotiated between sophisticated parties. Furthermore, under the relevant facts, the parties specifically defined "dispositions" to include only a direct sale of the property, and not the equity interest of the property holder (i.e., an indirect transfer). Therefore, the court found that the arm's length transaction was not a sham agreement designed to avoid the application of a preferential right. Other jurisdictions are not so welcoming of the two-step structure. In *Williams Gas Processing--Wamsutter Co. v. Union P. Resources Co.*, 25 P.3d 1064 (Wyo. 2001), the Wyoming Supreme Court found that the Texas Two-Step could not be used to circumvent a preferential right expressly applicable to a direct transfer, even with respect to a merger (an indirect conveyance that was not specifically prohibited by the underlying agreement), because the dance move was being used to specifically avoid the preferential right.

When determining whether a disguised third-party asset transfer has occurred, courts may look to see whether a legitimate business purpose exists with respect to the first step of the transaction—the initial transfer of the assets to a subsidiary of the seller. The court in *Fina Oil and Chemical Co.* relied on evidence of Amoco's legitimate reorganization that contemplated the transfer of its interest in the lease to a subsidiary and the fact that the buyer only submitted an offer for the stock of such subsidiary, and not for the properties such subsidiary owned. Courts have found that restructuring plans with the primary intent of consolidating or reorganizing assets (and the relevant title holder) based upon operating costs, financial performance or basin or area are all legitimate business purposes, so long as there is no evidence that the transfer was affected with the intent to circumvent transfer restrictions.

Instead of dancing the Texas Two-Step, a company may be able to "do-si-do" around limitations and adverse case law applicable to the Texas Two-Step using a divisive merger. A divisive merger, unlike a traditional merger that combines two entities into a single entity, is a transaction where a single entity divides into multiple entities. A divisive merger may be used as an alternative transaction structure for acquisitions and divestitures, and because the allocation and vesting of assets and liabilities is not considered a transfer or assignment, it is particularly beneficial to a sale where material assets and liabilities contain transfer restrictions. Although acquisitions and divestitures using a divisive merger may be structured in different ways, one structure involves (i) the seller divisively merging and allocating the assets and liabilities of the business it wants to retain to itself, as a surviving entity, and the assets and liabilities of the business it wants to dispose to a newly formed entity, and (ii) after the divisive merger, a third party purchasing the equity of the newly formed entity.

Only a few states permit divisive mergers, notably Delaware and Texas. Texas law provides that when a Texas entity divisively merges, the dividing entity's assets and liabilities are allocated to and vested in the dividing entity (if it survives) and each new entity without any transfer or assignment having occurred. In *Plastronics Socket Partners, Ltd. v. Dong Weon Hwang*, No. 2:18-cv-00014-JRG-RSP, 2019 WL 1009404 (E.D. Tex. Feb. 13, 2019), the court found that a patent that was allocated and vested through a divisive merger did not violate a provision in an agreement that stated the patent could not be transferred without consent. The court explained that the allocation and vesting occurred by operation of law and no prohibited transfer occurred. The court also observed that if the parties wanted to provide that a merger violated the transfer restriction, they could have done so.

In a bankruptcy context (more commonly when liabilities, rather than assets, are placed in a newly formed entity that then files for Chapter 11 protection), courts have permitted companies to use Texas's divisive merger statute. In *In re LTL Mgt., LLC*, 652 B.R. 433 (Bankr. D.N.J. 2023), the court found that a legitimate business purpose exists when a company restructures itself to manage pending litigation liability and provide flexibility in addressing the claims. A ruling regarding Johnson & Johnson's use of divisive merger to shield itself from talcum powder litigation identified one extra hurdle for divisive mergers, placing a good faith requirement on the financial distress of a company filing for bankruptcy.

Outside of bankruptcy, courts have sparingly, if ever, addressed the issue of divisive mergers. Time will tell whether, in the acquisition and divestiture arena, courts will require a legitimate business purpose to exist when a divisive merger occurs and assets are allocated to the newly formed entity, and whether the narrower or more cynical views regarding the Texas Two-Step will also be applied if the holder of a consent or preferential right challenges a divisive merger that precedes an indirect transfer. Divisive mergers are already being utilized in structured oil and gas transactions, including recent oil and gas securitizations, to facilitate the transfer of assets into new, special purpose entities. Those entities can either be sold to a third party or maintained as a new, bankruptcy-remote vehicle to issue indebtedness. Analogous to a Texas Two-Step, the divisive merger simplifies the transaction by ensuring all relevant assets transfer without application of some restrictions that may burden the assets.

While the law continues to evolve, companies may employ divisive mergers to effect reorganizations and corporate restructurings more efficiently, with one convenient byproduct being the ability to dance their way to more certain or expeditious outcomes with regard to applicable direct transfer restrictions.

District Court Dismisses Challenge to West Virginia Unitization Act

By Bridget D. Furbee and Garrett M. Spiker, Steptoe & Johnson PLLC

On March 20, the U.S. District Court for the Northern District of West Virginia dismissed *Sonda v. West Virginia Oil and Gas Conservation Commission* (No. 05:22-CV-00124 (N.D.W. Va. Mar. 20, 2024)) for lack of standing. The lawsuit was brought by mineral interest owners challenging the constitutionality of West Virginia Code § 22C-9-7a, which authorizes the unitization of nonconsenting interest owners' mineral tracts in horizontal well units. The District Court's initial opinion was reversed and remanded by the U.S. Court of Appeals for the Fourth Circuit on January 31, 2024 (92 F.4th 213 (4th Cir. 2024)), holding that the District Court erred in its abstention order.

In 2022, the mineral interest owners filed a lawsuit (Civil Action No. 5:22-CV-124) against the West Virginia Oil and Gas Conservation Commission in the District Court, claiming that West Virginia Code § 22C-9-7a violated their rights under provisions of the U.S. Constitution and the Constitution of West Virginia. The Commission filed a motion to dismiss, arguing that the mineral interest owners lacked standing and failed to state a claim upon which relief could be granted. Subsequently, the District Court dismissed all but two claims that were brought pursuant to the U.S. Constitution. The District Court abstained from ruling on the two claims, invoking the Pullman abstention doctrine and asserting that West Virginia constitutional law was "directly germane to the issues presented." The District Court stayed the matter so that the mineral interest owners could present the state law issues in West Virginia state court. The Commission appealed. The Fourth Circuit reversed the District Court, determining that the District Court should have first considered the issue of standing and instructed it to do so on remand. Further, the Fourth Circuit held that the Pullman doctrine was inapplicable here.

On remand, the Commission renewed its motion to dismiss the mineral interest owners' lawsuit, reiterating that the (1) mineral interest owners lacked standing, (2) Eleventh Amendment immunity bars all claims against the Commission, and (3) remaining counts failed to state a claim upon which relief could be granted. The District Court agreed that the mineral interest owners did not have standing to challenge the statute. In a supplemental briefing to the District Court, the Commission asserted that the mineral interest owners lacked standing to bring their claims because they failed to demonstrate (a) injury in fact and (b) traceability. The mineral interest owners' amended complaint did not state how their mineral interests had been impacted by the statute, whether their units were established after the statute was enacted, or whether the units were created involuntarily.

Thus, because the amended complaint did not allege how, or that, the mineral interests had been impacted, there was no actual concrete or threatened injury to the interest owners. Further, the District Court recognized that the mineral interest owners failed to satisfy the traceability requirement because there was not a causal connection between the alleged injury and the actions of the Commission. The amended complaint did not allege that the statute was being enforced against the mineral interest owners, that the Commission was affecting their mineral interests, or that future enforcement by the Commission would be sufficiently imminent and substantial. Because the mineral interest owners lacked standing, the District Court reasoned that there was no need to address the Commission's remaining arguments. Therefore, the District Court dismissed the mineral interest owners' amended complaint without prejudice.

Louisiana Case Clarifies that Some "Exclusive" Pipeline Servitudes May Not Be All That Exclusive

By Mitchell D. Diles, Miles O. Indest, Andrew F. Gann, Jr., and Anthony J. Carna, McGuireWoods LLP

On April 10, 2024, Louisiana's Second Circuit Court of Appeals released an important decision regarding pipeline servitudes. In *ETC Tiger Pipeline, LLC v. DT Midstream, Inc. and DTM Louisiana Gathering LLC*, No. 55,534-CA, the Court of Appeals reversed the trial court's decision to grant ETC a temporary restraining order (TRO) and preliminary injunction to prevent the appellants (collectively, DTM) from constructing a perpendicular pipeline under a pipeline owned and operated by ETC. Prior to that decision, in 2010, ETC obtained a Servitude of Use for Pipeline, which allowed the company to operate a 42-inch, high-pressure, high-volume natural gas pipeline from Panola County, Texas, through the pipeline servitude in DeSoto Parish, to Richland Parish.

The Dispute: Pipeline Crossings

According to the Second Circuit's opinion, in 2022, DTM informed ETC that it intended to cross ETC's pipeline servitude in DeSoto Parish with a 24-inch, 4-mile-long natural gas pipeline. Despite the parties meeting to discuss DTM's pipeline project, ETC repeatedly objected to DTM's pipeline route. But after DTM initiated a Louisiana One Call for information to cross ETC's pipeline servitude and an ETC employee observed staged pipe, ETC filed a petition and sought a TRO, preliminary injunction and permanent injunction against DTM. ETC argued that it had an "exclusive servitude" that prevented all other pipelines from crossing. The servitude granted to ETC, among other things, "an exclusive servitude of use" and provided for the maintenance of "one (1) pipeline for the transmission of natural gas. . . ." ETC also alleged that the DTM pipeline presented a safety and operation risk to ETC's high-pressure pipeline and would cause immediate and irreparable injury, among other things.

DTM's opposition explained that it made a good-faith effort to discuss its safety code compliance, construction standards, and industry customs and practices with ETC. DTM also disputed ETC's supposed "exclusive servitude" and explained that, at the location in question, its pipeline would cross several other adjacent and parallel pipelines. This included not only ETC's high-pressure pipeline, but also two 12-inch diameter pipelines owned by third parties. DTM's pipeline would also run approximately 19 feet below the largest pipeline and 25 feet below ETC's high-pressure pipeline.

After a hearing, the trial court granted ETC's preliminary injunction and denied DTM's preliminary injunction. According to the trial court, ETC's "exclusive servitude" gave ETC the right to block construction of a crossing pipeline. DTM appealed and argued that ETC's pipeline servitude did not allow ETC to use an unlimited depth or prevent another pipeline from crossing under ETC's high-pressure pipeline.

Louisiana Court of Appeals Decision

Louisiana's Second Circuit Court of Appeals reversed the preliminary injunction against DTM. In reaching that decision, the court concluded that ETC's pipeline servitude was a "personal servitude of right"—allowing a specified use of an estate less than full enjoyment—rather than a "predial servitude"—a charge on a servient estate for the benefit of a dominant estate. *Compare* La. C.C. art. 639, *with* La. C.C. art. 646.; *see also id.* art. 720, art. 730. It did so because, in Louisiana, a predial servitude necessarily involves two estates: a servient estate and a dominant estate. But rather than involve a servient and dominant estate, ETC's pipeline servitude simply represented a right of use.

The Second Circuit next addressed ETC's claim—and the trial court's decision—that ETC's pipeline servitude was "exclusive." The Second Circuit disagreed, concluding that the servitude's single use of the word "exclusive" did not convey to ETC the sole right to construct a pipeline at any depth underground, particularly when the servitude was silent regarding depth. The Second Circuit also explained that under the one-pipeline provision of ETC's pipeline servitude, ETC could not lay a second pipeline below its existing high-pressure pipeline. Finally, the Second Circuit concluded that ETC's pipeline servitude did not authorize ETC to prohibit underground crossings at safe depths.

Takeaways for All Jurisdictions

The Second Circuit's decision stands for the proposition that the holder of a pipeline personal servitude of right—at least in Louisiana—may not act as a bouncer to some exclusive property club. From a Louisiana policy perspective, the concurring opinion rejected the notion that, "through silence and/or ambiguity in an agreement, a landowner should be deprived of the rights of ownership and that the oil and gas industry should effectively be disrupted regarding the ability to construct and maintain necessary pipelines in Louisiana for transmission of oil and natural gas."

But pipeline operators in all jurisdictions should be mindful of several issues following the Second Circuit's decision. First, pipeline operators must ensure that pipeline crossings take place at safe distances. Second, pipeline operators should be mindful that crossing agreements can better provide boundaries to protect both companies should an issue arise. Finally, new or renegotiated easement and right-of-way agreements should consider clearance depth and the potential benefits of depth separation limits.

FERC and NERC Issue Joint Recommendations in Response to Winter Storm Elliott Potentially Impacting Well Head to the Burner Tip

By Kurt L. Krieger and Kevin W. Hivick Jr., Steptoe & Johnson PLLC

On November 7, 2023, the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC) issued a joint report including recommendations targeting the natural gas industry from the well head to power generators (the Recommendations). The report was in response to *Winter Storm Elliott*, an unprecedented winter weather event occurring from December 21, 2022, through December 26, 2022. During the storm, 90,500 MW of generating units went out of service, and a total of over 127,000 MW of generation was unavailable. These numbers represent an unprecedented 18% of eastern U.S. electric-generation resources. Natural gas fuel issues accounted for 20% of all causes (and 83% of outages caused by fuel issues). In the Marcellus Shale and Utica Shale formations, production dropped to just 54% during the event, the top causes of which were wellhead freeze-offs, natural gas supply chain equipment freezing, and weather-related transportation issues preventing maintenance, such as road conditions.

The Recommendations focus on natural gas production and FERC and non-FERC pipelines and fall into two categories: (i) those pertaining to cold-weather infrastructure reliability; and (ii) those pertaining to natural gas and electric-generation coordination for cold-weather reliability.

Recommendation 4, which is specific to natural gas production and other infrastructure cold-weather reliability, calls for legislation by Congress and state legislatures, as well as regulation by entities with jurisdiction over natural gas infrastructure reliability. Specifically, the Recommendations call for the establishment of reliability rules for natural gas production and gas infrastructure necessary to support the grid and natural gas local distribution companies (LDCs). The Recommendations specify that any potential legislation concerning cold-weather infrastructure reliability should address the following issues: (i) cold-weather preparedness plans, freeze protection measures, and operating measures for when extreme cold-weather periods are forecast, and during extreme cold-weather periods; (ii) the need for regional natural gas communications coordinators who can share timely operational communications throughout the natural gas infrastructure chain and communicate potential issues to, and receive grid reliability information from, grid reliability entities; and (iii) the need to require natural gas infrastructure entities to identify those natural gas infrastructure loads that should be designated as critical for priority treatment during load shed and provide criteria for identifying such critical loads.

Recommendations 5-7, which address natural gas and electric-generation coordination for cold-weather reliability, provide for the following: (i) convening natural gas infrastructure entities, electric grid operators, and LDCs to enhance situational awareness and improve communications in future extreme cold-weather events; (ii) considering whether to order FERC-jurisdictional natural gas entities to provide FERC reports describing their roles in assessing and responding to natural gas supply and transportation vulnerabilities in extreme cold-weather events; and (iii) calling for an independent research group to perform studies in early 2024 to consider if additional infrastructure, such as interstate natural gas pipelines and storage, is necessary to increase electric grid and LDC reliability.

The Recommendations will have long-term implications for both the natural gas and electric-generation sectors. In turn, it is critical for stakeholders to review the Recommendations and monitor FERC and NERC for further developments. A copy of the joint report is available here: https://www.ferc.gov/media/winter-storm-elliott-report-inquiry-bulk-power-system-operations-during-december-2022.

Louisiana Class VI Carbon Sequestration Primary Approval Meets a Stumbling Block Before the 5th Circuit

By Kat Statman, Baker Donelson

On January 5, 2024, the Environmental Protection Agency ("EPA") granted primacy to the State of Louisiana through the Louisiana Department of Natural Resources to permit Class VI injection wells for permanent carbon sequestration and storage under the Underground Injection Control ("UIC") program and the Safe Drinking Water Act ("SDWA"). *See* 40 CFR 147. Previously, only two other states had been granted primacy for Class VI wells, being Wyoming and North Dakota. While this development was celebrated across much of the energy industry — in part due to the significant benefits and incentives under the Inflation Reduction Act for carbon sequestration projects and the long permitting process for Class VI wells with the EPA — it was quickly challenged before the 5th Circuit.

Specifically, on February 22, 2024, the Alliance for Affordable Energy and Deep South Center for Environmental Justice, Healthy Gulf filed a Petition for Review challenging the EPA's granting of primacy to Louisiana for the permitting of Class VI injection wells. *See Deep South Center for Environmental Justice, Healthy Gulf, and Alliance for Affordable Energy v. United States Environmental Protection Agency; Michael S. Regan*, Case No. 24-60084. Without explaining their specific arguments in support of their request, the Petitioners asked the court to "hold unlawful, vacate, and set aside the final rule, and grant any such further relief as may be deemed just and proper." *Id.* at Doc. 1-1. This challenge to the EPA's Class VI primacy decision is still in its early stages, with the Petitioners' brief in support of their Petition currently due May 13, 2024.

The current permitting process for a Class VI well with the EPA is quite lengthy, with the EPA stating it takes approximately 25 months to obtain a permit; however, in practice the process often takes much longer. *See* https://www.epa.gov/uic/primary-enforcement-authority-underground-injection-control-program-0. In some instances, permitting applications have taken more than six years to be approved. Notably, as of January 1, 2024, the EPA has only issued six Class VI injection well permits. In January 2024, two new Class VI permits were granted in Indiana to Archer Daniels Midland Company Wabash Carbon Services, LLC after an application approval process that spanned seven years. See EPA Approves Permits for Controversial Carbon Sequestration Fertilizer Project, *available at:* https://indianacapitalchronicle.com/2024/01/29/epa-approves-permits-for-controversial-carbon-sequestration-fertilizer-project/. Both of these Class VI permits have already been challenged to the Environmental Appeals Board of the EPA. *See In re Wabash Carbon Services, LLC Class VI Underground Injection Permits Permit Nos. IN-165-6A-0001 (Vermillion) and IN-167-6A-0001 (Vigo)*, UIC Appeal No. 24-01.

Many states are closely watching the outcome of the challenge to the EPA's ruling granting primacy to Louisiana in the hopes that they will be able to obtain primacy as well. For example, Texas has already begun the process of applying for primacy for Class VI injection wells. Although the Texas Railroad Commission first started updating their requirements for Class VI injection wells as early as 2021, the primary process remains in the "Pre-Application Activities" phase. *See* https://www.epa.gov/uic/primary-enforcement-authority-underground-injection-control-program-0.

The decision on whether to grant Texas primacy of Class VI wells is likely to hinge heavily on the outcome of the Petition before the 5th Circuit on the granting of primacy to Louisiana. This, however, creates some additional difficulties for ongoing Class VI projects in Texas. Currently, due to changes in regulations by the Texas Railroad Commission as part of seeking primacy for Class VI wells in Texas, to obtain a Class VI permit, an operator must not only obtain a permit from the Railroad Commission, but also from the EPA. *See* https://www.rrc.texas.gov/oil-and-gas/applications-and-permits/injection-storage-permits/co2-storage/. The Railroad Commission has indicated that it is working closely with the EPA so that the review and approval process is on a parallel track; however, this does create an added regulatory hurdle until and unless Texas is granted primacy for Class VI wells. Projects such as the Bayou Bend Carbon Capture project in Southeast Texas may be impacted by these changing rules and processes. *See* https://www.12newsnow.com/article/news/local/bayou-bend-carbon-capture-project-future-proof-southeast-texas-industry/502-d1e143f7-55b2-46a1-8a45-47c581cea26e.

One of the primary issues as it relates to primacy that was presented to the EPA through the notice and comment process and addressed in the EPA's final rule granting primacy is Louisiana's Long-Term Liability statute and whether it complies or directly conflicts with the SDWA. *See* 40 CFR 147, at 706–07. In the EPA's final rule issued on January 5, 2024, the EPA concluded that it "disagrees that long term liability provisions are always incompatible with the SDWA and the EPA's UIC regulatory requirements" and further required some additional changes to the Louisiana site closure requirements to comport with federal requirements as well as an updated Memorandum of Agreement with the Louisiana Department of Natural Resources regarding Class VI wells. *See id.* at 707–08. Of note, certain states (including Wyoming which has been awarded Class VI primacy) have also enacted laws to relieve a party from long-term liability for the storage of CO2 or have adopted laws allowing the state to assume the responsibility for stored CO2. Additionally, other states have established funds from fees paid by parties conducting sequestering operations to allow the state to assume such responsibilities. Texas is one of these states. *See* H.B. 2446, Section 4.

Additionally, the Petition may potentially be impacted by the current challenges to *Chevron* deference pending before the Supreme Court in *Relentless, Inc. v. Department of Commerce,* Docket No. 22-1219 and *Loper Bright Enterprises v. Raimondo*, Docket No. 22-451. It is possible that the EPA may receive less deference for its determinations going forward regarding primacy and granting of Class VI well permits. The impact that a change in *Chevron* deference may have on current and long-term carbon sequestration projects in the United States is yet to be seen.

For the reasons outlined above, the 5th Circuit's ruling on the Petition for Review challenging the EPA's granting of primacy to Louisiana for the permitting of Class VI injection wells is likely to have a significant impact on the energy industry and other states' attempts to seek primacy for Class VI injection wells. While the outcomes of challenges to the granting of primacy to states, or even simply the granting of new Class VI permits by the EPA, are not yet known, it is clear that this is going to be an evolving area of the law as the courts, federal and state agencies, and the energy industry at large work to develop carbon sequestration projects, take advantage of the current administration's policies supporting these efforts, and continue in efforts to combat climate change.

EPA Finalizes Air Rule Targeting Oil and Gas Industry Methane Emissions

By Timothy J. Sullivan, Madeleine Boyer, Eric Christensen, David Friedland, Lauren Karam, and Nikki Waxman, Beveridge & Diamond PC

On December 2, 2023, during the United Nations Climate Change Conference (COP28), the U.S. Environmental Protection Agency (EPA) announced a final Clean Air Act rule designed to reduce emissions of methane and other pollutants from operations in the oil and natural gas industry. The rule includes New Source Performance Standards (NSPS) to reduce methane and volatile organic compound (VOC) emissions from new, modified, and reconstructed sources. (40 C.F.R. Part 60, Subpart OOOOb). It also includes first-time emissions guidelines (EG) to guide states in developing plans to address existing sources' methane emissions. (40 C.F.R. Part 60, Subpart OOOOc).

A. Who is Impacted?

The rule applies to owners and operators of sources in the Crude Oil and Natural Gas source category. This source category covers sources involved in:

1. _Crude oil production_, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline or any other forms of transportation; and
2. _Natural gas production, processing, transmission, and storage_, which include the well and extend to, but do not include, the local gas distribution company custody transfer station (i.e., the city-gate).

B. What Should I Do??

This rule is lengthy and complex, containing several new or revised standards relative to the earlier oil and gas NSPS. Accordingly, oil and gas source owners/operators covered by this rule should carefully review the rule to understand their compliance requirements. It is also important for oil and gas companies to understand the rule's costs so that those costs can be appropriately considered in transactions where these sources are bought and sold.

Owners/operators should consider auditing a representative subset of their facilities to understand potential compliance needs across their operations. Sources that have recently commenced construction or performed work that could constitute a modification or reconstruction should assess whether and how the work subjects that source to these new requirements.

Given this rule's focus on methane emissions and the Biden-Harris Administration's commitment to addressing climate change and environmental justice issues, oil and gas source owners/operators should expect additional EPA and state scrutiny of their operations' Clean Air Act compliance, especially with respect to these new or revised requirements. This enhanced scrutiny could come in the form of on-the-ground inspections, remote sensing inspections (including flyovers), information requests, and, where violations are identified, the initiation of formal enforcement actions.

The final rule will become effective 60 days after publication in the Federal Register. The final rule was published on March 8, 2024, and any party planning to file a petition for judicial review of this final rule must do so within 60 days of such publication date.

C. Analysis and Notable Elements of the Final Rule

This rule has been in the works since the Biden-Harris Administration announced the U.S. Methane Emissions Reduction Action Plan at COP26 two years ago, and it is intended to work in tandem with the Inflation Reduction Act's methane fee and programs to address emissions from a variety of sources and support methane monitoring programs. The final rule builds on the proposed rule EPA issued one year ago in conjunction with COP27, which proposed, among other measures, the novel and controversial Super Emitter Response Program.

EPA is finalizing four distinct actions through this rule:

1. New Source Performance Standards regulating greenhouse gas (GHG) emissions from new sources (in the form of limitations on methane emissions) and VOC emissions under Section 111(b) of the Clean Air Act;
2. Emissions guidelines for states to follow in developing, submitting, and implementing plans to limit GHG emissions (in the form of methane limitations) from existing sources under Section 111(d) of the Clean Air Act;
3. Several related actions flowing from Congress' June 30, 2021 joint resolution under the Congressional Review Act disapproving EPA's 2020 Policy Rule (85 Fed. Reg. 57018); and
4. A protocol under the general provisions of 40 C.F.R. Part 60 related to using optical gas imaging (OGI) for leak detection.

The final rule requires stringent equipment standards and work practices for new and existing sources. These include:

- **The Super-Emitter Program.** The rule includes the much-discussed Super-Emitter Program.

This Program is designed to identify and remedy abnormally large methane emission events known as "super-emitter" events (i.e., a methane leak that has a quantified emission rate of 100 kilograms per hour or more).

- EPA initially proposed that an EPA-approved entity or regulatory authority could directly notify a responsible owner/operator of a potential super-emitter event. After receiving the third-party notice, the responsible owner/operator would have been required to perform a root cause analysis and take any necessary corrective actions to address the emissions identified in the third-party notice. Industry raised concerns with the proposed Program's legality because it would create regulatory obligations based on unaffiliated third parties' monitoring and notifications. Industry also expressed concern about a lack of standard methods for detecting super-emitter events.
- EPA revised the proposed Program to address some of these concerns and strengthen its Program oversight. Under the final Program, EPA will certify third parties to collect data using approved remote-sensing technologies and submit notifications of the potential super-emitter event to EPA. EPA will receive and analyze the super-emitter notifications and data provided by third parties. When EPA determines that a notification has met specified conditions, it will notify the responsible owner/operator of the super-emitter event, and the owner/operator will have five days to initiate an investigation of the event and report results to EPA within 15 days after receiving the notification. If the source of the super-emitter event is subject to the NSPS or a state or federal plan under the EG, the owner/operator must address the leak consistent with applicable requirements.

- **Phasing Out Routine Natural Gas Flaring at New Oil Wells.** Over a two-year period, the rule phases out and will eventually prohibit routine flaring of associated gas at new oil wells. Wells will be required to route the gas to a sales line, use it as an onsite fuel source or for another useful purpose, or reinject it into the well or another well. Existing sources have options for addressing routine flaring depending on their level of methane emissions. Sources should carefully review these requirements, including when associated gas may be routed to a flare or control device.

- **Legally and Practicably Enforceable Limits for Storage Vessels (Tank Batteries).** For the first time, EPA is specifying criteria that must be satisfied for a permit limit or other requirement to qualify as a legally and practicably enforceable limit to determine whether a source is an affected facility covered by the NSPS or designated facility covered by the EG. If a facility is subject to emissions limits that are designed to keep emissions below the applicability threshold in a permit or through other regulatory requirements, and the limits meet the specified criteria, the facility does not have to comply with the NSPS or EG. A legally and practicably enforceable limit must include:
  - Quantitative production and/or operational limits for equipment;
  - A 30-day or less averaging period if a production limit is used;
  - Established parametric production and/or operational limits, and a compliance demonstration if a control device is used to meet an operational limit;
  - Ongoing parametric limit monitoring to demonstrate continuous compliance; and
  - Recordkeeping and periodic reporting demonstrating continuous compliance.

Owners/operators seeking to limit their emissions so that they are not subject to the NSPS or EG should carefully review these requirements to ensure that their emissions limits meet these criteria.

- **Leak Detection and Repair.** The rule includes several important elements affecting leak detection and repair requirements. The nature of the facility (e.g., single well facility, multi-well facility, compressor station, onshore natural gas processing plant) determine the specific requirements. Related issues include the ability to use advanced methane detection technology work practices as alternatives to the specified leak detection requirements and the new OGI monitoring protocol, Appendix K to 40 C.F.R. Part 60 (Appendix K).
  - *Advanced Methane Detection Technology Work Practices*. Advanced methane detection technologies include satellite monitoring, aerial surveys, and continuous monitoring to detect leaks, including super-emitter events. These technologies operate as an alternative to ground-based OGI surveys, EPA Method 21 (an alternative to OGI), and audio, visual,

olfactory (AVO) inspections. The rule includes a process for companies to seek EPA approval for using an advanced technology instead of the specified monitoring methods.

- *Appendix K*. The rule contains a protocol for using OGI for leak detection. While the rule finalizes Appendix K, its application is broader. On its own, Appendix K does not apply to any sources; however, it is applicable when specified in a particular subpart. In the final rule, EPA requires Appendix K to be used for leak detection at onshore natural gas plants (EPA Method 21 may be used as an alternative) under both the NSPS and EG.

- **Use of Best Management Practices to Minimize or Eliminate the Venting of Emissions During Gas Well Liquids Unloading.** New and existing gas wells must implement techniques or technologies to minimize or eliminate venting emissions to the atmosphere during gas well liquids unloading events.

- **State Plan Requirements for Existing Sources.** The final rule includes emissions guidelines (presumptive standards for existing sources that define the minimum standards State Implementation Plans must meet) for states as they develop plans addressing existing oil and gas sources' methane emissions. States will have 24 months to submit plans after publication of the rule. The final rule requires state plans to have designated facilities achieve compliance with applicable standards within 36 months of state plan submittal.

- **Other Important Elements.** Other important rule provisions include:

    - For operations outside of Alaska, process controllers (formerly referred to as pneumatic controllers) must meet a methane and VOC emissions rate of zero; and

    - First-time standards for dry seal compressors.

A Message from IEL

The Institute for Energy Law is now accepting applications for the 7th Leadership Class (2024-25). This prestigious program is primarily for energy professionals who have been practicing in the energy field between three and twelve years. For more information about the program and how to apply, visit the Leadership Class webpage. Deadline to apply is **June 3, 2024**.

Once again, we would like to thank our IEL publications liaisons – this issue has been a great success and we appreciate your support! If you are interested in being your firm or company's publication liaison to IEL, please contact Diana Prulhiere (diana.prulhiere@steptoe-johnson.com) and Emma Espey (eespey@cailaw.org).

MEMBERS IN THE NEWS

Megan E. Griffith (Susman Godfrey LLP), member of IEL's 6th Leadership Class, recently co-authored a piece published by the American Bar Association Litigation Section's Alternative Dispute Resolution Committee. Read Megan's article, "Navigating a Timed Arbitration: Strategies and Challenges in the Race Against the Clock."

Brandon Duke (Winston & Strawn LLP), member of IEL's 6th Leadership Class, recently authored a piece published in the Texas Journal of Oil, Gas, and Energy Law, Vol. 19, 2024. In his article, "Inland Litigation under the Outer Continental Shelf Lands Act," Brandon explains why companies should invoke the Outer Continental Shelf Lands Act to litigate a broad range of onshore and offshore commercial disputes in federal court.

NEW MEMBERS

We are honored and excited to add the following companies and individuals to IEL's membership roster. Please join us in welcoming them to our organization!

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