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FEDERAL — MINING

Wells Parker, Benjamin Machlis & Kayla Weiser-Burton
– Reporters –

Infrastructure Act Provisions Pertaining to Federal Mining Activities

On November 5, 2021, the U.S. House of Representatives passed the Infrastructure Investment and Jobs Act, Pub. L. No. 117-58, 135 Stat. 429 (2021), which, among other things, contains provisions related to federal mining activity. Specifically, the Act contains provisions with respect to abandoned hardrock mine land reclamation as well as the domestic research and development of critical minerals.

First, the Act appropriates $3 billion to address abandoned hardrock mine reclamation activities. *Id.* § 40704(e)(1). Fifty percent of these funds is allocated for grants to states and Indian tribes that have jurisdiction over abandoned hardrock mine lands, and 50% is allocated to the Secretary of the Interior to address similar concerns on federal land managed by the Bureau of Land Management (BLM). *Id.* The Secretary may transfer funds to the Secretary of Agriculture for addressing abandoned mine lands on National Forest System lands. *Id.* § 40704(e)(2). Funds may only be used for federal, state, tribal, local, and private land or water resources that have been affected by past hardrock mining activity, including those used

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FEDERAL — OIL & GAS

Kathleen C. Schroder
– Reporter –

Federal Oil and Gas Royalty Valuation Rules Upheld

In *Cloud Peak Energy Inc. v. U.S. Department of the Interior*, Nos. 2:19-cv-00120, 2:19-cv-00121, 2:19-cv-00126, 2021 WL 5150682 (D. Wyo. Sept. 8, 2021), the U.S. District Court for the District of Wyoming upheld the federal oil and gas royalty valuation rules issued in 2016 by the Office of Natural Resources Revenue (ONRR) (2016 Rules). Petitioner American Petroleum Institute (API) had challenged the 2016 Rules in a case that was consolidated with challenges to ONRR's royalty valuation regulations for federal and Indian coal. *See id.* at *1–2. In 2019, the same court declined to preliminarily enjoin the 2016 Rules. *See Cloud Peak Energy Inc. v. U.S. Dep't of the Interior*, 415 F. Supp. 3d 1034 (D. Wyo. 2019); Vol. XXXVI, No. 4 (2019) of this *Newsletter*.

API presented multiple objections to the 2016 Rules, which the court rejected. The court consistently found that ONRR adequately explained its reasons for instituting the objectionable provisions of the 2016 Rules.

First, the court held that ONRR did not act arbitrarily or capriciously by discontinuing its "Deep Water Policy" for offshore production, which allowed the deduction of costs associated with moving oil or gas from the seafloor manifold to the first

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RENEWABLE ENERGY

Mark D. Detsky, Gabriella Stockmayer & K.C. Cunilio
– Reporters –

FERC Explores Transmission and Generator Interconnection Reform

This summer the Federal Energy Regulatory Commission (FERC) opened an advance notice of proposed rulemaking (ANOPR) in Docket No. RM21-17-000, entitled "Building for the Future Through Electric Regional Transmission Planning and Cost Allocation and Generator Interconnection," 176 FERC ¶ 61,024 (2021).

The ANOPR process can be used by an agency like FERC as a precursor to the more formal notice of proposed rulemaking (NOPR). In NOPRs, FERC provides a draft version to update or institute new rules that could result in the adoption of a final rule. An ANOPR can be utilized to obtain public comments to regulatory and policy changes at an early stage before FERC has come to a decision on a particular change or developed strawman rules. FERC's authority to issue ANOPRs and NOPRs is derived from section 206 of the Federal Power Act, 16 U.S.C. § 824e.

This transmission ANOPR is requesting public comments in advance of FERC undertaking a potential comprehensive change through the NOPR process to update the FERC Order No. 1000 process as well as the generator interconnection process in FERC Order No. 2003. *See* Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Order No. 1000, 136 FERC ¶ 61,051 (2011); Standardization of Generator Interconnection Agreements and Procedures, Order No. 2003, 104 FERC ¶ 61,103 (2003).

FERC notes that a decade has passed since the landmark Order No. 1000 was entered, and additional reforms to the re-

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for, or affected by, hardrock mining activity, and those lands with inadequate reclamation. *Id.* § 40704(c). Eligible uses of funds include inventorying, assessing, decommissioning, reclaiming, responding to the release of hazardous substances upon, and the remediation of abandoned hardrock mine lands. *Id.* § 40704(d)(1). Funds may not be used to fulfill obligations under the Comprehensive Environmental Response, Compensation, and Liability Act. *Id.* § 40704(d)(2).

Second, the Act contains provisions relating to the discovery and development of critical minerals. It establishes within the U.S. Geological Survey an initiative titled the "Earth Mapping Resources Initiative" to carry out the mapping of domestic mineral resources. *Id.* § 40201(b), (c). The initiative will use a whole ore body approach as opposed to a single commodity approach in order to emphasize recoverable critical minerals within a certain area or specific deposit. *Id.* § 40201(e)(2). The initiative is directed to prioritize the mapping and assessment of critical minerals. *Id.* § 40201(e)(3). With respect to developing critical minerals on federal land, the Secretaries of the Interior and Agriculture are directed to complete the requisite federal permitting and review processes "with maximum efficiency and effectiveness." *Id.* § 40206(c).

The affiliated reconciliation bill, the Build Back Better Act, H.R. 5376, 117th Cong. (2021), also contains a provision directing the Secretary of the Interior to withdraw, permanently or for a set term and subject to valid existing rights, lands or interests in lands administered by the BLM on or before June 30, 2024. *See* Rules Comm. Print 117-18, 117th Cong. § 70709 (2021). The bill provides that such withdrawals shall result in an aggregate reduction of receipts payable to the U.S. Department of the Treasury by the end of fiscal year 2031 of $10 million. *Id.* The current draft of the bill does not provide any further directives relating to this withdrawal provision. Notably, while prior versions of the bill included a provision creating a royalty on minerals extracted from unpatented mining claims and significant changes to the fees associated with unpatented mining claims, the most recent text of this bill has removed all language concerning a federal royalty or increased fees on hardrock minerals.

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offshore platform. *Cloud Peak*, 2021 WL 5150682, at *6. The court found that ONRR acknowledged its change in policy and provided a rational justification for it. *See id.* Further, the court repeatedly cited ONRR's determination that the policy did not conform to the agency's definition of "gathering," the costs of which are not deductible. *See id.* at *5–6.

Second, the court held that ONRR did not act arbitrarily or capriciously by capping transportation and processing allowances at 50% of the value of the oil or gas. *Id.* at *7. The court accepted ONRR's reasoning that the agency has considerable discretion to determine the value of production, which includes allowable deductions. *See id.*

Third, the court held that ONRR did not act arbitrarily or capriciously by requiring that gas not sold in an arm's-length transaction be valued using the highest reported monthly bidweek price at index pricing points. *Id.* at *9. The court accepted ONRR's explanation that the new method does not overinflate value because this method does not require the lessee to unbundle transportation and processing costs. *Id.* Similarly, in response to API's argument that the new method is unrealistic because it requires the use of the highest index price even if

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gas did not go to that index price point, the court accepted ONRR's justification that it is providing lessees administrative convenience by not requiring them to trace where gas was actually sold. *Id.*

Fourth, the court held that ONRR did not act arbitrarily or capriciously by requiring lessees to have written contracts for production sales and for transportation and processing services in order for ONRR to accept the lessee's royalty value. *Id.* at *11. The court observed that, although this requirement may pose problems for lessees, ONRR had adequately explained its reasons for the requirement. *Id.*

Fifth, the court upheld a provision of the 2016 Rules that allows ONRR to determine the value of production, a transportation allowance, or a processing allowance if a lessee's value is more than 10% lower or higher than reasonable measures of these values. *Id.* at *10–11. The court reasoned that the "10 percent threshold" is a guide that allows, but does not require, ONRR to determine the value of production, a transportation allowance, or a processing allowance. *Id.* at *10.

Finally, the court upheld "default provisions" in the 2016 Rules that, if triggered, allow ONRR to determine the value of production. *Id.* at *11–12. API had argued these provisions afforded ONRR "unbridled discretion" to determine royalty value. *Id.* at *11. The court reasoned that these provisions were a fallback rather than a primary method of valuation, and further, relied on ONRR's representation that it would use "market-based transaction data" to determine value. *Id.*

API has appealed the decision to the U.S. Court of Appeals for the Tenth Circuit. The appeal has been docketed as No. 21-8076. At the time of this report, no briefs have been filed.

On September 30, 2021, ONRR withdrew its revisions to the 2016 Rules that were published in the *Federal Register* on January 15, 2021, *see* 86 Fed. Reg. 4612 (Jan. 15, 2021) (to be codified at 30 C.F.R. pts. 1206, 1241), but that never became effective. *See* 86 Fed. Reg. 54,045 (Nov. 1, 2021). Therefore, the 2016 Rules will remain in effect unless the Tenth Circuit orders otherwise.

BLM Did Not Adequately Analyze Air Quality and Wilderness Before Leasing in Colorado

In *Rocky Mountain Wild v. Haaland*, No. 1:18-cv-02468, 2021 WL 4438032 (D. Colo. Sept. 28, 2021), the U.S. District Court for the District of Colorado determined that the Bureau of Land Management (BLM) erred by issuing federal oil and gas leases in western Colorado that BLM had offered at its June 2018 lease sale. Specifically, the court held that BLM did not comply with the National Environmental Policy Act (NEPA) when issuing the leases because BLM did not adequately analyze potential impacts to air quality and lands with wilderness characteristics.

First, the court held that BLM did not sufficiently analyze the results of air quality modeling to predict ozone impacts. *Id.* at *4. BLM had not prepared new NEPA analysis to support issuance of the leases but instead had adopted the analysis in an environmental assessment (EA) prepared in 2017 that analyzed a similar leasing decision(2017 EA). *Id.* at *1. Relying on projections from BLM's ozone model, the 2017 EA disclosed that ozone levels would remain relatively constant and may decline by 2021. *Id.* at *2. After BLM issued the 2017 EA, however, BLM updated its ozone model. *Id.* The updated model predicted exceedances of the National Ambient Air Quality Standard (NAAQS) for ozone in certain portions of western Colorado by 2025. *Id.* at *4. Observing that the exceedances of the ozone NAAQS had previously occurred in these areas, the court held that NEPA required BLM to consider the updated ozone modeling in its leasing analysis. *Id.*

Second, the court held that BLM did not adequately consider impacts from leasing on lands with wilderness characteristics. *Id.* at *6. BLM analyzed lands with wilderness characteristics and made management decisions for these lands when it issued the resource management plan (RMP) for the Little Snake Field Office in 2011. *See id.* at *5. Later, however, BLM determined that additional lands managed by the Little Snake Field Office possessed wilderness characteristics. *Id.* Neither the RMP nor the 2017 EA discussed the particular impacts of leasing on these lands. *See id.* The court held that NEPA required BLM to consider whether its determination that these lands possessed wilderness characteristics "warranted a change in the management priorities" under the existing RMP. *Id.* at *6.

Having determined that BLM did not comply with NEPA before issuing the leases, the court remanded the leases to BLM for further analysis and expressly declined to vacate the leases. *See id.* at *8. As justification for remand rather than vacatur, court observed that lessees had expended capital in anticipation of developing some leases. *Id.* at *7. More significant, the court found that the NEPA violations "are relatively minor and are unlikely to prompt fundamentally different decisionmaking by the BLM upon remand" with respect to all of the challenged leases. *Id.* at *8 (footnote omitted). The court observed that, after BLM prepared additional NEPA analysis on remand, BLM likely would not "reject the entire slate of proposed leases." *Id.* Thus, the court held that "wholesale vacatur of all of the . . . leases would be excessively disruptive." *Id.*

BIA Broadly Interprets "Dedicated" Contracts Under ONRR Indian Gas Royalty Valuation Regulations

In *Roddy Production Co.*, ONRR-17-0132-IND (Feb. 1, 2021), the Director of the Bureau of Indian Affairs (BIA) construed the Office of Natural Resources Revenue's (ONRR) Indian gas valuation regulations to limit when producers may utilize index pricing. Roddy Production Company, LLC (Roddy) had appealed an order to perform restructured accounting and pay additional royalties on production from oil and gas leases on Jicarilla Apache tribal lands. *Id.* at 1. In the order, ONRR determined that Roddy "did not report and pay royalties on gas . . . based on the higher of two values—the index-based value adjusted for alternative dual accounting or Roddy's arm's-length dedicated contract value," among other issues. *Id.*

ONRR's Indian gas valuation regulations provide that, when gas is produced within an index zone, different valuation standards apply depending on whether or not the lessee's gas sales contract is a "dedicated" arm's-length contract, as defined by ONRR's regulations. *Id.* at 4. If the arm's-length contract is "dedicated," then the royalty value is the greater of the index-based value or the gross proceeds accruing to the lessee under

EDITOR'S NOTE ON UNPUBLISHED OPINIONS: This *Newsletter* sometimes contains reports on unpublished court opinions that we think may be of interest to our readers. Readers are cautioned that many jurisdictions prohibit the citation of unpublished opinions. Readers are advised to consult the rules of all pertinent jurisdictions regarding this matter.

its arm's-length sales contract. *Id.* (citing 30 C.F.R. §§ 206. 172(b)(3), .174(b), recodified at 30 C.F.R. §§ 1206.172(b)(3), .174(b)). If the arm's-length contract is not "dedicated," royalty value is based on the index price. *Id.* (citing 30 C.F.R. § 206. 172(b)(2), recodified at 30 C.F.R. § 1206.172(b)(2)).

ONRR's Indian gas valuation regulations define "dedicated" as "a contractual commitment to deliver gas production (or a specified portion of production) from a lease or well when that production is specified in a sales contract *and* that production must be sold pursuant to that contract to the extent that production occurs from that lease or well." *Id.* at 5 (quoting 30 C.F.R. § 206.171, recodified as 30 C.F.R. § 1206.171).

The BIA Director held that Roddy's natural gas purchase agreements met the definition of "dedicated" contracts. First, the BIA Director found the agreements contained "contractual commitments to sell a specified portion (i.e., quantity) of gas production." *Id.* Although the natural gas purchase agreements did not set forth specific quantities of production to be sold, the BIA Director looked to the monthly confirmation letters issued under the agreements that identified the amount of gas that Roddy agreed to sell. *See id.* Second, the BIA Director observed that these confirmation letters identified the points of production (wellhead meters) where the gas would be sold. *Id.*

The BIA Director rejected Roddy's argument that the natural gas purchase agreements were not "dedicated" because Roddy could have sold its production to another party. *Id.* The BIA Director first noted that Roddy had not actually sold production to another party. *Id.* Further, the BIA Director observed that ONRR's definition of a "dedicated" contract does not require that a contract obligate the sale of all of a producer's gas but only requires that a producer sell a specified amount of production. *Id.*

The decision is significant because many gas sales contracts are structured similarly to Roddy's contracts. This decision therefore undercuts the convenience of index-based royalty valuation for Indian gas sold pursuant to arm's-length contracts because, for its initial report, an Indian lessee with a dedicated contract must undertake the complex determination of gross proceeds accruing under the gas sales contract, which also requires unbundling under the marketable condition rule, and pay on the higher of the index-based value or the gross proceeds value. The Indian lessee also will still have to do accounting by comparison (i.e., dual accounting), if applicable.

Roddy has appealed this decision to the Interior Board of Land Appeals.

BLM Publishes Guidance on Permitting on Oil and Gas Leases Subject to Litigation

On October 14, 2021, the Bureau of Land Management (BLM) published Permanent Instruction Memorandum No. 2022-001 (PIM 2022-001), which provides guidance to BLM for its processing and review of applications for permits to drill (APD) where a federal court has directed further review of National Environmental Policy Act (NEPA) analysis supporting BLM's decision to issue a federal oil and gas lease or BLM has decided to complete further review of a leasing decision for consistency with court decisions.

PIM 2022-001 confirms that BLM may continue to process APDs on leases for which it is reviewing the underlying leasing decisions. First, it directs that BLM, when reviewing "an APD on a lease that was issued based on that lease decision[,] should ensure that the analysis for the individual APD . . . is reflected in the supplemental or additional environmental analysis for that APD or [master development plan (MDP)]."

Second, PIM 2022-001 cautions BLM not to "presume that the mere existence of underlying NEPA documentation is a sufficient basis for BLM to rely on a [categorical exclusion]." It particularly identifies the categorical exclusion in section 390 of the Energy Policy Act of 2005, which does not require that BLM prepare an environmental assessment or environmental impact statement when

> [d]rilling an oil or gas well within a developed field for which an approved land use plan or any environmental document prepared pursuant to NEPA analyzed such drilling as a reasonably foreseeable activity, so long as such plan or document was approved within 5 years prior to the date of spudding the well.

42 U.S.C. § 15942(b)(3). PIM 2022-001 notes that "BLM's further review of the NEPA document(s) underlying the lease may raise a question as to whether those document(s) 'analyzed . . . drilling' and therefore qualify for a categorical exclusion."

Further, PIM 2022-001 directs BLM to publish environmental analyses for APDs or MDPs tied to a lease under review for a 30-day public comment period.

Finally, PIM 2022-001 instructs BLM to elevate APDs that raise "potentially significant impacts or unique or controversial issues" to the BLM Headquarters Office before completing the environmental analysis.

Because hundreds of federal oil and gas leases issued since 2015 have been challenged in federal court and remanded to BLM for additional NEPA analysis, this instruction memorandum provides BLM with guidance as to how to analyze proposed development on such leases.

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gional transmission planning and cost allocation and generator interconnection processes are warranted now. In particular, FERC is concerned about the lack of success of the regional transmission planning and cost allocation processes, which have not resulted in many projects to date. In addition, a primary motivation of the new rule is to explore the relationship between renewable energy generation and the current state of transmission planning requirements.

FERC notes that the increased penetration of renewable energy resources across the country has led to a change in the transmission planning and generation interconnection paradigms, and questions whether the two processes should become more linked. FERC asserts a concern that "the generator interconnection process is not designed to consider how to address anything beyond the reliability interconnection-related network upgrades required for a specific interconnection request or group of interconnection requests." ANOPR, at P 32.

As a result, FERC preliminarily concludes that "there is reason to question the contention in Order No. 2003 that participant funding provides more 'efficient price signals and a more equitable allocation of costs than the crediting approach.'" *Id.* at P 42 (quoting Order No. 2003, at P 695). "Also, while the crediting policy 'recognizes the reliability benefits of a stronger transmission infrastructure and more competitive power markets that result from a policy that facilitates the interconnection of new generating facilities,'" *id.* (quoting Order No. 2003-A, 106 FERC ¶ 61,220, at P 584 (2004)), FERC has raised questions "on whether there are improvements that can be made to the crediting policy or whether a different pricing policy may be more efficient," *id.*

Participant funding of interconnection upgrades has been the standard operating procedure for connecting all generation in the last decade and a half. However, FERC appears to believe that renewable generation, often located in areas geographically remote from load centers, has changed the public interest analysis. In particular, FERC states that "the large-scale changes since Order No. 2003 may have impacted the underlying rationale for the interconnection pricing policy," *id.* at P 100, and therefore seeks comments on whether it should modify the participant funding and crediting policies and declare "participant funding of interconnection-related network upgrades [to] be unjust and unreasonable," *id.* at P 123.

These changes, if approved, could have dramatic effects on the transmission landscape as it has developed since open access to transmission was first formalized in FERC Order No. 888 in 1996. *See* Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, FERC Stats. & Regs. ¶ 31,036 (1996).

The ANOPR requests comments in the areas of oversight of transmission infrastructure development, regional transmission planning, and interconnection queue processes. ANOPR, at P 5. Initial comments in this ANOPR docket were due by October 12, 2021, and responsive comments are due by November 30, 2021. *See id.* at P 183; Notice of Extension of Time, Docket No. RM21-17-000 (Sept. 3, 2021). FERC scheduled a remote, staff-led technical conference on regional transmission planning in the ANOPR to be held on November 15, 2021. *See* Notice of Technical Conference, 86 Fed. Reg. 52,664 (Sept. 22, 2021).

Generator comments have focused on consolidation of the historically siloed transmission system planning and generation interconnection policies. Utilities have cautioned about potential impacts to reliability and deferring to utility versus generator priorities.

The ANOPR is also occurring in conjunction with a recently created joint FERC-National Association of Regulatory Utility Commissioners task force that is composed of FERC's four commissioners along with 10 state commissioner representatives. *See* Joint Federal-State Task Force on Electric Transmission, Order Establishing Task Force and Soliciting Nominations, 175 FERC ¶ 61,224 (2021) (Docket No. AD21-15-000).

Overall, it appears the transmission ANOPR will be the first step of many by FERC to assist in tackling President Joe Biden's goals of 100% clean electricity and the creation of a carbon-neutral U.S. economy.

CONGRESS / FEDERAL AGENCIES – GENERAL

John H. Bernetich & Dale Ratliff
– Reporters –

CEQ Issues Proposed Rule Partially Revoking Trump Administration's Changes to NEPA Regulations and Reinstating Prior Regulations

On October 7, 2021, the Council on Environmental Quality (CEQ) issued a proposed rule that, if finalized, would revoke some changes made by the Trump administration to CEQ's regulations adopted in 1978 to implement the National Environmental Policy Act (NEPA). *See* NEPA Implementing Regulations Revisions, 86 Fed. Reg. 55,757 (proposed Oct. 7, 2021) (to be codified at 40 C.F.R. pts. 1502, 1507, 1508). CEQ's proposed rule would restore rules in place for decades prior to the Trump administration's action regarding key components of NEPA regulations. *See* Update to the Regulations Implementing the Procedural Provisions of NEPA, 85 Fed. Reg. 43,304 (July 16, 2020) (to be codified at 40 C.F.R. pts. 1500–1518) (revising 1978 regulations); *see also* Vol. XXXVII, No. 3 (2020) of this *Newsletter*. CEQ stated that it intends to use a "phased approach" in revising the NEPA regulations. 86 Fed. Reg. at 55,759. The October 2021 proposed rulemaking is Phase 1 of the approach, and CEQ stated its intent to issue a Phase 2 rulemaking making additional changes to its NEPA regulations at an unspecified later date. *Id.*

The October 2021 Phase 1 rulemaking would revoke regulatory changes issued by the Trump administration and restore regulations adopted by CEQ in 1978 on three key topics: (1) the purpose and need of a proposed action, (2) agency NEPA procedures for implementing CEQ's NEPA regulations, and (3) the definition of "effects."

Purpose and Need. The CEQ regulations require each environmental impact statement (EIS) to specify the proposed project's purpose and need. The purpose and need statement informs the alternatives to the proposed project and the scope of the environmental analysis in the EIS. The Trump administration narrowed the scope of the purpose and need statement to describe only the "applicant's goals and the agency's statutory authority." 85 Fed. Reg. at 43,330. The proposed Phase 1 rule would unwind this revision and broaden agency authority to consider other factors in describing the project's purpose and need, including the public interest, "desired conditions on the landscape," "local economic needs," and others. 86 Fed. Reg. at 55,760.

Agency NEPA Procedures. Regulations adopted in 1978 provided that the CEQ regulations represented the minimum requirements for agencies' compliance with NEPA, and permitted agencies to adopt stricter regulations of their own. *See id.* at 55,761. The Trump administration adopted changes providing that the CEQ regulations were the "ceiling" for agency NEPA compliance and that agencies could not adopt their own stricter requirements. The proposed Phase 1 rule would revert to the pre-Trump administration approach. Under the proposed rule, the CEQ regulations "provide a floor for environmental review procedures" and would "enabl[e] agencies to address their specific programs and the contexts in which they operate." *Id.*

Effects or Impacts. NEPA requires agencies to consider "any adverse environmental effects" and "impact[s]" of proposed actions. 42 U.S.C. § 4332(2)(C). The 1978 CEQ regulations defined "effects" to include "direct" and "indirect" effects. "Impacts" included "cumulative impacts" of the action, or impacts when added to other past, present, or reasonably foreseeable future actions. The Trump administration jettisoned these definitions, and instead defined "effects or impacts" to mean effects of the proposed action that are "reasonably foreseeable and have a reasonably close causal relationship to the proposed action or alternatives." 85 Fed. Reg. at 43,375. The Biden administration's Phase 1 rulemaking would restore the 1978 definitions. 86 Fed. Reg. at 55,762–63. This proposed change would require consideration of direct effects, indirect effects, and cumulative impacts of the proposed action.

In addition to once again requiring consideration of cumulative effects, the Phase 1 proposed rule would remove provisions in the Trump administration's rule that (1) stated that a "but for" causal relationship is insufficient to trigger consideration of a particular effect; (2) excluded the requirement to consider effects that are remote in time, geographically remote, or the product of a lengthy causal chain; and (3) excluded the requirement to consider effects that the agency has no ability to prevent. *Id.* at 55,762. If finalized, the Phase 1 rulemaking would revoke each of these provisions. CEQ signaled that return to the pre-Trump administration requirement to consider cumulative impacts is intended to ensure that agencies adequately consider climate change impacts as part of NEPA reviews. *Id.* at 55,763–64.

CEQ signaled that its planned Phase 2 rulemaking will "broadly revisit" the 2020 NEPA regulations and propose further revisions to ensure "efficient and effective environmental reviews" consistent with NEPA. *Id.* at 55,759.

FWS & NMFS Propose to Rescind Trump-Era Critical Habitat Rules

On October 27, 2021, the U.S. Fish and Wildlife Service (FWS) and the National Marine Fisheries Service (NMFS) (collectively, Services) published two proposed rules to rescind critical habitat regulations finalized during the waning days of the Trump administration. Both proposed rules would wholesale rescind the 2020 regulations. *See* Regulations for Listing Endangered and Threatened Species and Designating Critical Habitat, 86 Fed. Reg. 59,353 (proposed Oct. 27, 2021) (to be codified at 50 C.F.R. pt. 424); Regulations for Designating Critical Habitat, 86 Fed. Reg. 59,346 (proposed Oct. 27, 2021) (to be codified at 50 C.F.R. pt. 17).

Definition of "Habitat"

On December 16, 2020, the Services added a definition of "habitat" to their regulations implementing the critical habitat provisions in the Endangered Species Act (ESA). *See* Regulations for Listing Endangered and Threatened Species and Designating Critical Habitat, 85 Fed. Reg. 81,411, 81,421 (Dec. 16, 2020) (to be codified at 50 C.F.R. pt. 424). The definition of "habitat" provides that "[f]or the purposes of designating critical habitat only, habitat is the abiotic and biotic setting that currently or periodically contains the resources and conditions necessary to support one or more life processes of a species." 50 C.F.R. § 424.02.

The Services adopted the new definition, at least in part, in response to the U.S. Supreme Court's decision in *Weyerhaeuser Co. v. FWS*, 139 S. Ct. 361 (2018). In *Weyerhaeuser*, the Court held that section 4(a)(3)(A)(i) of the ESA, 16 U.S.C. § 1533(a)(3)(A)(i), "does not authorize the Secretary to designate the area as *critical* habitat unless it is also *habitat* for the species." *Weyerhaeuser*, 139 S. Ct. at 368. This can include unoccupied areas, but it must qualify as habitat in the first instance. *Id.* at 369. The Court did not provide a definition of "habitat," and in the 2020 regulations, the Services sought to provide clarity to what the Court deemed as a critical first step in designating critical habitat—determining if it qualifies as habitat in the first instance. 85 Fed. Reg. at 81,417.

The 2020 regulation was immediately controversial because it potentially excluded the designation of unoccupied habitat that was necessary for the species' survival but required modification or restoration in order to support the species in the future. This was the issue in *Weyerhaeuser*. *See Markle Interests, L.L.C. v. FWS*, 827 F.3d 452, 470 (5th Cir. 2016) (finding that FWS reasonably determined that unoccupied habitat that required modification in order to support the species in the future was essential to the species' survival and qualified as critical habitat), *vacated and remanded sub nom. Weyerhaeuser Co. v. FWS*, 139 S. Ct. 361 (2018).

In the proposed rule the Services state that

> the broad definition of "conservation," along with the statute's recognition of destruction or loss of habitat as a key factor in the decline of listed species (in section 4(a)(1) of the [ESA]), indicates that areas not currently in an optimal state to support the species could nonetheless be considered "habitat" and "critical habitat."

86 Fed. Reg. at 59,354. By rescinding the definition of "habitat" added in the 2020 rule, the Services propose to revert to the case-by-case determination for designating unoccupied critical habitat consistent with the Services' practices pre-*Weyerhaeuser* but with the Court's undefined mandate to determine that they must first determine what qualifies as habitat in making these determinations. *Id.* at 59,355.

Discretion to Exclude

The other rule proposed by FWS will rescind a 2020 regulation codifying criteria FWS must rely on when determining whether to exclude areas from a critical habitat designation. *See* Regulations for Designating Critical Habitat, 85 Fed. Reg. 82,376 (Dec. 18, 2020) (to be codified at 50 C.F.R. pt. 17); *see also* Vol. XXXVII, No. 4 (2020) of this *Newsletter*.

The 2020 rule promulgated binding criteria for FWS's determination on whether to exclude lands from critical habitat designations under section 4(b)(2) of the ESA, 16 U.S.C. § 1533(b)(2). *See* 50 C.F.R. § 17.90. In doing so, it codified a non-binding policy jointly published by the Services during the Obama administration. *See* 81 Fed. Reg. 7226 (Feb. 11, 2016).

As we previously reported, one of the major implications of the 2020 rule was its potential effect on lands subject to habitat conservation plans (HCPs) under section 10 of the ESA, 16 U.S.C. § 1539. The ability of FWS to designate lands subject to an HCP as critical habitat has historically been in tension with the certainty intended to be provided to participants in these agreements. The 2020 rule explicitly included specific criteria for FWS to consider "[w]hen analyzing the benefits of including or excluding particular areas covered by conservation plans, agreements, or partnerships that have been authorized by a permit under section 10 of the [ESA]." 50 C.F.R. § 17.90(d)(3). And the preamble to the final rule confirmed FWS's position that it "place[s] great value on the partnerships that are developed during the preparation and implementation of plans, agreements, or partnerships that have been permitted under section 10 of the [ESA]" and "anticipate[s] consistently excluding areas covered by plans, agreements, or partnerships as long as the conditions in paragraphs (d)(3)(i)–(iii) are met." 85 Fed. Reg. at 82,382–83.

The proposed rule to rescind the 2020 exclusion criteria makes little mention of the intersection with section 10 and the potential impact to HCP participants. FWS acknowledges that the 2020 rule "identifies factors for the Secretary to consider in evaluating impacts related to economics, national and homeland security, and conservation plans that are or are not permitted under section 10 of the [ESA]." 86 Fed. Reg. at 59,350. But the agency takes the position that because the factors "are mostly the same" as those identified in the 2016 policy "it is unnecessary to include these provisions in the regulations and that, if the [2020 rule] is rescinded, resuming the implementation of the [2016 policy] would not alter [FWS's] implementation of section 4(b)(2) of the [ESA] with respect to these factors." *Id.* at 59,350–51. While this approach may sound rational on paper, it ignores the distinction between a binding regulation and informal policy, and fails to acknowledge that decreasing the certainty provided HCP participants may disincentivize participation in this important program.

FWS Reinstates Strict Migratory Bird Protections

On October 4, 2021, the U.S. Fish and Wildlife Service (FWS) revoked a rule issued by the Trump administration that had limited the scope of the Migratory Bird Treaty Act's (MBTA) enforcement provisions. *See* Regulations Governing Take of Migratory Birds; Revocation of Provisions, 86 Fed. Reg. 54,642 (Oct. 4, 2021) (to be codified at 50 C.F.R. pt. 10) (effective Dec. 3, 2021). The prior rule, issued in January 2021, limited the MBTA's definition of prohibited "take" of covered birds to only "intentional" takes. *See* Regulations Governing Take of Migratory Birds, 86 Fed. Reg. 1134, 1137 (Jan. 7, 2021) (to be codified at 50 C.F.R. pt. 10); *see also* Vol. XXXVIII, No. 1 (2021) of this *Newsletter*. The October 2021 rule reinstated the agency's prior interpretation of the MBTA prohibiting both intentional and unintentional (i.e., incidental) takes of migratory birds. Under the new rule, the MBTA prohibits taking or killing a migratory bird, regardless of whether the actor intended to take or kill a migratory bird.

The MBTA makes it a crime to pursue, hunt, take, capture, or kill any migratory bird or any migratory bird nest or egg. 16 U.S.C. § 703(a). Federal courts have disagreed on whether the MBTA prohibited only intentional acts meant to harm a migratory bird, or whether it prohibited both intentional and unintentional acts. *See United States v. CITGO Petroleum Corp.*, 801 F.3d 477, 488–89 (5th Cir. 2015) (limiting scope of MBTA to only "deliberate acts done directly and intentionally to migratory birds"); *United States v. FMC Corp.*, 572 F.2d 902, 906–07 (2d Cir. 1978) (specific intent to take a migratory bird is not required); *United States v. Apollo Energies, Inc.*, 611 F.3d 679, 690 (10th Cir. 2010) (specific intent not required but defendant's actions must have proximately caused the take).

In the October 2021 rule, FWS announced plans to develop a new rule that prohibits incidental take of migratory birds that may include a regulatory framework for authorizing incidental take in certain defined circumstances. *See* 86 Fed. Reg. at 54,642. FWS published an advance notice of proposed rulemaking concurrently with the October 2021 rule in order to gather the necessary information for developing the new rule and authorization framework. *See* 86 Fed. Reg. 54,667 (Oct. 4, 2021). FWS requested comments on three potential frameworks: (1) an exemption of certain types of actions from the ban on incidental take, (2) a "general" permit that would authorize on a "blanket" basis certain activities subject to specified conditions, and (3) a "specific" permit that would authorize individual citizens or entities to conduct activities that may result in incidental take. *Id.* at 54,669. FWS will accept public comments on its proposal until December 3, 2021.

Until FWS takes further action, the agency will prohibit any incidental take, subject to enforcement discretion, consistent with judicial precedent and pre-2017 agency practice. 86 Fed. Reg. at 54,643–44. Along with the October 2021 rule, however, FWS issued a director's order acknowledging that "a wide range of activities may result in incidental take of migratory birds" and that pursuing all potential violations "would not be an effective or judicious use of our law enforcement resources." Director's Order No. 225, § 5 (Oct. 5, 2021). Accordingly, FWS announced that it would focus enforcement efforts on incidental takes that are foreseeable or the result of otherwise illegal activity. *Id.* Until further notice, FWS will not prioritize enforcement of incidental takes that result from otherwise legal activity or where the entity conducts activities in accordance with prescribed practices designed to avoid and minimize incidental take. *Id.*

The scope of the MBTA's ban on incidental take and FWS's priorities in enforcing the MBTA are rapidly evolving. We expect additional action in the coming months providing clearer guidance regarding the ban on incidental take and, potentially, a regulatory scheme providing certainty about precisely which activities may result in enforcement of the MBTA's strict penalties.

ENVIRONMENTAL ISSUES

Randy Dann, Kate Sanford & Michael Golz
– Reporters –

EPA Proposes Rule Aimed at Reducing VOC and Methane Emissions from Both New and Existing Oil and Gas Facilities; U.S. Supreme Court Will Review Scope of EPA's Authority to Regulate GHGs

<u>EPA's Proposed Rule</u>

On November 15, 2021, the U.S. Environmental Protection Agency (EPA) published a proposed rule regarding new source performance standards (NSPS). *See* Standards of Performance for New, Reconstructed, and Modified Sources and Emissions Guidelines for Existing Sources: Oil and Natural Gas Sector Climate Review, 86 Fed. Reg. 63,110 (proposed Nov. 15, 2021) (to be codified at 40 C.F.R. pt. 60). Parts of the proposed rule reverse the Trump administration's regulations regarding volatile organic compounds (VOC) and methane emissions and, if adopted, will have significant impacts on the upstream and midstream oil and gas sectors.

EPA's broad proposal sets forth three actions that it will take. First, EPA proposed a new subpart, subpart OOOOb (Quad Ob), that will impact new, modified, and/or reconstructed sources in the oil and natural gas sector. The applicability date of the rules for these sources will be determined by the publication of the final rule in the *Federal Register*. NSPS Quad Ob will create several new requirements at applicable sites, including:

- *Storage Vessels*. EPA's proposal changes the NSPS applicability for a storage vessel to depend on the VOC emissions from the storage tank battery. For new, modified, and reconstructed storage tanks or tank batteries with a potential to emit (PTE) of 6 or more tons per year (tpy) of VOCs, owners and operators would be required to reduce VOC and methane emissions by 95%. *Id.* at 63,119. This proposal will likely expand the number of storage vessels subject to NSPS applicability and requirements.
- *OGI Inspections*. EPA's proposal would require more frequent optical gas imaging (OGI) inspections to find and fix fugitive emissions at applicable facilities. EPA's proposal would require quarterly OGI inspections at facilities with methane emissions greater than or equal to 8 tpy and semi-annual OGI inspections at facilities with methane emissions greater than or equal to 3 tpy. *Id.* at 63,118–19. That said, EPA has requested comment to evaluate whether it should shift from the proposed quarterly OGI monitoring to a monitoring program using alternative measurement technologies. *Id.* at 63,116.

- *Well Liquids Unloading*. EPA's proposal also includes an increase in well liquids unloading control and best management practices. The proposal would require that well liquids unloading activities result in zero emissions, unless technically infeasible or unsafe. *Id.* at 63,119. If an operator can demonstrate technical infeasibility or safety issues, the well liquids unloading activities would be subject to the use of best management practices. *Id.* Importantly, although included in Quad Ob (as applicable to new, modified, and/or reconstructed facilities), EPA notes that any instance of an existing facility conducting a well unloading activity would be considered a modification. *Id.* at 63,180. Accordingly, from the date of that unloading activity, an existing facility would be subject to these proposed requirements.
- *Pneumatic Controllers*. EPA's proposal also targets pneumatic controllers, requiring new and existing sources to use "zero-emission" pneumatic controllers. *Id.*
- *Flaring Requirements*. EPA's proposal prohibits flaring of natural gas unless the operator shows that a gas sales line is not accessible. *Id.* at 63,120. EPA does not clearly define what determines whether a sales line is "accessible," but it solicits comment on this question.

Second, EPA has proposed a new subpart, subpart OOOOc (Quad Oc), which would create emission guidelines that target existing oil and natural gas sources. These emission guidelines are intended to inform state regulators regarding the development, submittal, and implementation of state specific plans that meet or exceed emission reduction standards for oil and natural gas facilities. *Id.* at 63,116. The Quad Oc requirements largely mirror the Quad Ob proposal, with different applicability thresholds. EPA's Quad Oc proposal includes:

- *Storage Vessels*. For existing storage tanks or tank batteries with a PTE of 20 or more tpy of methane, owners and operators would be required to reduce methane emissions by 95%. *Id.* at 63,121.
- *OGI Inspections*. EPA's proposal would require more frequent OGI inspections to find and fix fugitive emissions at existing facilities. For well sites, EPA creates three tiers of inspection frequencies. For well sites that emit less than 3 tpy of methane, EPA's proposal would require verification of the facility's actual emissions. *Id.* For well sites greater than or equal to 3 tpy, EPA proposed two alternatives. The first would require quarterly inspections at all facilities greater than or equal to 3 tpy. *Id.* Alternatively, EPA proposed semi-annual inspection frequency for facilities with a PTE greater than or equal to 3 tpy and less than 8 tpy, while requiring quarterly inspections at all facilities with a PTE greater than or equal to 8 tpy. *Id.* The proposal would also require quarterly inspections at compressor stations. *Id.*
- *Well Liquids Unloading*. As noted above, any single instance of a well unload will subject an existing facility to the Quad Ob requirements.
- *Pneumatic Controllers*. Similar to Quad Ob, Quad Oc also targets pneumatic controllers, requiring the use of "zero-emission" pneumatic controllers at existing facilities. *Id.*
- *Flaring Requirements*. Once again similar to Quad Ob, Quad Oc prohibits flaring of natural gas unless the operator shows that a gas sales line is not accessible. *Id.* at 63,122.

Following the finalization of the Quad Oc emission guidelines, each state must create regulations that meet EPA's proposal. States are expected to take several years to develop and submit their plans. Following submittal, EPA will then review and potentially approve the plan. This process will likely extend to 2025 or beyond.

Finally, EPA proposed to update the existing NSPS subpart OOOOa (Quad Oa) rules to address a June 30, 2021, joint resolution adopted under the Congressional Review Act, which disapproved of the Trump administration's 2020 amendment to the Quad Oa rules, 85 Fed. Reg. 57,018 (Sept. 14, 2020) (to be codified at 40 C.F.R. pt. 60), known generally as the Quad Oa "Policy Rule." *See* S.J. Res. 14, 117th Cong. (2021); Vol. XXXVIII, No. 2 (2021) of this *Newsletter* (Congress/Federal Agencies report). The Trump-era Policy Rule rescinded VOC and methane emission standards for transmission and storage sectors as well as methane emission standards for the production and processing sectors. If the EPA's proposed revisions are adopted, the methane standards adopted prior to the 2020 Policy Rule will be reinstated. Ultimately, the Quad O/Oa proposals are expected to include the original 2016 methane standards for applicable production and processing oil and gas segments. *See* 86 Fed. Reg. at 63,157.

In addition to the sources and regulations described above, EPA is soliciting comment on several other potential emission sources that may be included in a supplemental rule. EPA is evaluating several different emission sources, including:

- Financial assurance and fugitive emissions monitoring at plugged and abandoned wells. *Id.* at 63,241–42.
- Reducing the frequency of pigging events, eliminating or reducing the volume of gas vented during pigging blowdowns, and/or using add-on controls that are applied to blowdown emissions during pigging. *Id.* at 63,242–44.
- Requiring emission controls during truck loadout operations. *Id.* at 63,244–45.
- Additional avenues to ensure control devices are operating functionally, including additional flare monitoring or testing. *Id.* at 63,245–47.

Stakeholders have 60 days from the publication of the proposed rule to submit comments, including specific items for which EPA has requested feedback. After the 60-day comment period, EPA will evaluate these comments before publishing the final rule. Quad Ob will likely be final and effective in late 2022. However, state regulations addressing EPA's Quad Oc emission guidelines may not be promulgated until 2025 or later.

<u>Supreme Court's Review of EPA Authority</u>

Recent developments in the U.S. Supreme Court may have additional implications for the oil and gas sector. On October 29, 2021, the U.S. Supreme Court agreed to review the U.S. Court of Appeals for the D.C. Circuit's decision in *American Lung Ass'n v. EPA*, 985 F.3d 914 (D.C. Cir. 2021), striking down the Trump administration's rollback of Obama-era greenhouse gas (GHG) emission standards for existing power plants. *See West Virginia v. EPA*, No. 20-1530, 2021 WL 5024616 (U.S. Oct. 29, 2021). The Court will review the scope of EPA's authority to regulate GHGs under section 111(d) of the Clean Air Act (CAA). This case gives the Court the opportunity to review and potentially reverse its seminal decision in *Massachusetts v. EPA*, 549 U.S. 497 (2007), in which it held that EPA has authority under the CAA to regulate GHGs. If the Court overturns *Massachusetts v. EPA*, EPA could no longer issue rules directly regulating GHG emissions, and past GHG rules issued under its CAA authority would be invalid. A ruling is expected next summer.

ALASKA – OIL & GAS

Jonathan E. Iversen
– Reporter –

2021: Another Year of Uncertainty for Alaska Taxpayers

It is no secret that the oil and gas industry—and revenues from it—are vital to the state of Alaska and its citizens, and the oil and gas industry is a major employer in the state. "Unrestricted" revenues, meaning revenues available to fund general state operations and capital projects, have historically been the focus of the budget debate that recurs annually in Alaska, with the governor and various factions of the legislature sparring over competing agendas. Unrestricted revenues largely comprise royalties for oil produced from state leases and three types of taxes:

(1) *Oil and Gas Production Tax*. A production (severance) tax levied on oil and gas produced in the state with a base tax rate of 35% of the net proceeds of production. Alaska Stat. §§ 43.55.011–.180.

(2) *Petroleum Property Tax*. An ad valorem tax of 20 mills (2%) levied on the assessed value of oil and gas exploration, production, and pipeline transportation properties in the state; municipalities and boroughs receive proceeds based on their mill rates, with the remainder to the state. *Id.* §§ 43.56.010–.210.

(3) *Corporate Income Tax*. A net income tax of up to 9.4% on a corporation's Alaska taxable income. For oil and gas corporations, Alaska taxable income is determined by apportioning worldwide income to Alaska relative to the rest of the world based on (i) tariffs and sales, (ii) oil and gas production, and (iii) oil and gas property. *Id.* §§ 43.20.011–.053.

Alaska's oil and gas production taxes, royalties, and corporate income taxes are all sensitive to prices and production volumes. Rising oil prices have been a shot in the arm for Alaska's revenue stream. Nevertheless, as in many previous years, Alaska's fiscal structure was front and center during the 2021 regular session of the Alaska legislature—and the *four* special sessions that followed.

Although Governor Mike Dunleavy did not introduce legislation to increase taxes, several legislators did. None of the bills passed, but the bills that were introduced during the regular session carry over for consideration in the next regular session, which starts in January 2022. Several of the bills directly target the oil and gas industry:

- Senate Bill 13 would increase state property taxes on oil and gas exploration, production, and pipeline transportation properties (such as wells, pipelines, production facilities, and equipment) from 20 mills (2% of assessed value) to 30 mills (3% of assessed value). This increase would go entirely to state coffers, as opposed to being shared with the municipalities in which the properties are located.
- Senate Bill 107 is like the Fair Share Act Initiative proposal to overhaul the oil and gas production tax that voters firmly rejected in the November 2020 election. *See* Elwood Brehmer, "Oil Tax Increase Defeated, but Revenue Issue Remains," *Alaska J. of Commerce* (Nov. 18, 2020); *see also* Vol. XXXVII, No. 1 (2020) of this *Newsletter*. The tax increase would apply to oil produced from fields that have produced 400 million barrels of oil in total and more than 40,000 barrels of oil in the previous year. It would increase tax rates, limit use of tax credits, add complicated reporting requirements, and make sensitive information publicly available.
- House Bill 130 would make Alaska's income tax on corporations apply to any oil or gas business entity, defined as "a person engaged in the production of oil or gas from a lease or property in the state or engaged in the transportation of oil or gas by pipeline in the state." This would include pass-through entities as well as individuals and joint ventures. The bill would also reject the changes made to the income tax net operating loss provisions by the Coronavirus Aid, Relief, and Economic Security Act (CARES Act) such that Alaska's treatment of net operating losses would follow the law as it read before the CARES Act was enacted (this section of the bill applies to all corporate income taxpayers).
- Senate Bill 106 would impose an income tax on any entity of 9.4% of income from oil and gas production or transportation in Alaska in excess of $4 million in a tax year. The tax would not apply to corporations already subject to corporate income taxes.

Legislators also introduced several tax bills aimed at the oil and gas industry in the third special session (August 16–September 14) and fourth special session (October 4–November 2):

- House Bill 4002 and House Bill 3007 would substantially reduce an oil and gas production tax credit allowed per barrel of oil produced from most Alaska North Slope fields.
- House Bill 4004 and House Bill 3005 would increase the oil and gas production tax North Slope minimum tax to 6% of wellhead value for oil in 2022 and 2023 (current highest minimum tax rate is 4% of wellhead value) and would suspend current tax rates until 2024.
- Senate Bill 3002 would substantially reduce an oil and gas production tax credit allowed per barrel of oil produced from most Alaska North Slope fields, apply the corporate income tax on any entity of 9.4% on "qualified taxable income" over $4 million (entity includes a sole proprietorship, partnership, or S corporation), and increase the motor fuel tax.

None of these bills passed, but they all foreshadow continuing debate on taxes during the upcoming regular session.

Meanwhile, oil and gas companies that earned rebatable oil and gas production tax credits under Alaska Stat. §§ 43.55.023 and 43.55.025 for investment in Alaska oil and gas exploration, development, and production have been left without payment by the state for any portion of them for over two years. *See* Letter from Alaska Dep't of Revenue (DOR), to Senate President Peter Micciche (R) and House Clerk (Feb. 5, 2021). As of March 15, 2021, $744 million in tax credits awaited purchase, and almost half of this queue dates back to credits earned before 2017. *See* Tax Div., Alaska DOR, "Spring 2021 Revenue Forecast," at 18 (Mar. 15, 2021); *see also* Letter from Alaska DOR, to the Alaska Legislature (Jan. 29, 2020). The operating budget bill introduced by Governor Dunleavy included a proposed appropriation of $60 million for tax credit purchases in fiscal year 2022 based on a statutory formula. *See* House Bill 69, 2021 Leg., 2d Special Sess. (Alaska 2021). The budget bill and related documents are published by the Alaska Office of Management and Budget (OMB). The formula is based on production tax revenues and oil prices: when oil prices are forecast by DOR to be $60 per barrel or higher, the percentage of production tax revenues is 10%, whereas it is 15% of production tax revenues when oil prices are forecast to be less than $60 per barrel. Alaska Stat. § 43.55.028(c). Because the governor released the proposed budget legislation on December 11, 2020, the inputs that yielded $60 million came from DOR's fall forecast. *See* Tax Division, Alaska DOR, "Revenue Sources Book Fall 2020," at 74 (Dec. 11, 2020). However, DOR's spring forecast projected higher production tax revenues, so the formula yielded $114 million and the governor amended his budget bill accordingly. *See* Tax Division, Alaska DOR, "Spring 2021 Revenue Forecast," at 18 (Mar. 15, 2021); Alaska OMB, "FY 2022 Operating Amendments Backup" (Apr. 19, 2021).

No appropriations for payments for the tax credits were passed in the regular, first, or second special sessions. In the third special session, the version of House Bill 3003 voted upon by the House of Representatives included $114 million to align with DOR's calculation based on the statutory formula, but $60 million of that was to be funded through the Constitutional Budget Reserve, a savings account that requires a three-fourths supermajority vote to access—a vote that was not obtained. The Senate passed the bill without amendment and thus $54 million will be the payment for rebatable tax credits for fiscal year 2022 absent further action. No legislation was passed in the fourth special session.

CALIFORNIA – MINING

Christopher L. Powell & Ryan Thomason
– Reporters –

Mining and Geology Board Amends Regulations for Appeals on Reclamation Plans and Amendments Thereto, and Orders to Comply with SMARA

On March 19, 2021, the California State Mining and Geology Board (Board) amended regulations governing the procedures for appealing to the Board concerning the denial of approval of a reclamation plan pursuant to section 2770 of the California Surface Mining and Reclamation Act of 1975 (SMARA), Cal. Pub. Res. Code §§ 2710–2796.5. *See* 12-Z Cal. Regulatory Notice Reg. 320 (Mar. 19, 2021) (to be codified at Cal. Code Regs. tit. 14, §§ 3650–3659) (effective July 1, 2021). While the previous regulations allowed appeals relating to new reclamation plans, the regulations did not explicitly allow appeals for consideration of reclamation plan amendments. The regulations were updated by the Board to explicitly include appeals concerning proposed reclamation plan amendments. *See, e.g.*, Cal. Code Regs. tit. 14, §§ 3651(a), 3652(a)(5), 3653(a), 3656(b)(2). Importantly, the amended regulations require a notice of hearing regarding an appeal to include "[a] statement inviting the supervisor [of the Division of Mine Reclamation] to provide comments on the adequacy of the proposed reclamation plan or plan amendment whether or not the supervisor had previously provided comments to the lead agency pursuant to [Cal. Pub. Res. Code § 2772.1]." Cal. Code Regs. tit. 14, § 3656(b)(6). Further, the amended regulations add the following actions to the sequence of such public hearings: (1) a statement on behalf of the supervisor of the Division of Mine Reclamation, (2) rebuttal on behalf of the lead agency, and (3) rebuttal on behalf of the supervisor of the Division of Mine Reclamation. *Id.* § 3658(a)(4), (7)–(8).

In addition, on July 23, 2021, the Board amended regulations governing the procedures for appeals to the Board concerning orders to comply with SMARA, which are issued by the supervisor of the Division of Mine Reclamation. *See* 30-Z Cal. Regulatory Notice Reg. 957 (July 23, 2021) (to be codified at Cal. Code Regs. tit. 14, §§ 3940–3948) (effective Oct. 1, 2021). The amendments were promulgated for the purpose of conforming to statutory changes in SMARA. *Id.* The amended regulations do not alter operators' ability to appeal an order to comply. They do, however, provide more comprehensive procedures regarding such appeals, which were not previously provided in the regulations. *See, e.g.*, Cal. Code Regs. tit. 14, § 3940.5(a). For example, the amended regulations now provide a list of documents, each of which must be submitted to the Board for an appeal to be accepted as complete. *Id.* Further, the Board's amended regulations provide the following criteria that must be considered by the Chair of the Board when determining whether the Board has jurisdiction: (1) "[w]hether the filing of the appeal with the Board is within the time limits provided for in [Cal. Pub. Res. Code § 2774.1(a)(3)(B)]" (i.e., within 30 days from the date on which the order to comply was issued); and (2) "[w]hether the appeal specifically addresses the alleged violations contained in the orders to comply, and together with any supporting documentation, is reasonably sufficient to substantiate the operator's appeal of the order to comply." Cal. Code Regs. tit. 14, § 3941(a).

CALIFORNIA – OIL & GAS

Tracy K. Hunckler & Megan A. Sammut
– Reporters –

Appellate Court Affirms State Law Preemption of Monterey County's Measure Z Initiative on Oil and Gas Operations

In November 2016, Monterey County voters passed Measure Z—an initiative to amend the County's general plan to add three new land use policies. All three provisions were framed as limiting land uses in the county's unincorporated areas. LU-1.21 would prohibit "Land Uses . . . in support of well stimulation treatments"; LU-1.22 would prohibit "Land Uses . . . in support of oil and gas wastewater injection or oil and gas wastewater impoundment"; and LU-1.23 would prohibit "Land Uses in Support of Drilling New Oil and Gas Wells." *Chevron U.S.A., Inc. v. Cty. of Monterey*, 285 Cal. Rptr. 3d 247, 250 (Ct. App. 2021).

Shortly thereafter, six separate lawsuits challenging Measure Z were filed against Monterey County in Monterey County Superior Court. The parties stipulated to stay the effective date of Measure Z, and the six lawsuits—brought by Aera Energy LLC, Chevron U.S.A. Inc., California Resources Corporation, National Association of Royalty Owners-California, Inc., Eagle Petroleum, LLC, and Trio Petroleum LLC—were consolidated into a single action "for purposes of the 'Phase 1' trial, which was to resolve the facial challenges to Measure Z, including preemption and takings." *Id.* at 251 n.4. Protect Monterey County (PMC) intervened in the actions.

Phase 1 consisted of a multi-day trial, after which the trial court issued an extensive decision finding that the plaintiffs lacked standing to challenge LU-1.21 because no plaintiff was using well stimulation treatments in Monterey County, but that LU-1.22, which barred wastewater injection and impoundment, and LU-1.23, which banned new wells, were preempted by state law. More specifically, the trial court found the latter provisions of Measure Z to be preempted by Cal. Pub. Res. Code § 3106, which provides the State Oil and Gas Supervisor with authority to decide whether to permit the drilling of new wells or the utilization of wastewater injection in oil and gas operations. The trial court additionally found LU-1.22 was preempted because state law fully occupies the field of oil and gas operation, and because it conflicted with the State's authority under the Safe Drinking Water Act (SDWA). It similarly found LU-1.23 conflicted with the SDWA. *Chevron*, 285 Cal. Rptr. 3d at 251–52. While Measure Z purported to be a land use prohibition, the trial court found no "meaningful distinction between wastewater injection and impoundment on the one hand, and surface equipment and activities in support of wastewater injection and impoundment on the other." *Id.* at 251. As for the facial takings claim, the trial court found both LU-1.22 and LU-1.23 would cause a taking as to any plaintiffs with no active wells, but would not cause a taking as to plaintiffs with active wells. *Id.* at 252. In any event, because both provisions were preempted the court found no remedy was necessary. *Id.*

After the trial court entered judgment and issued a writ of mandate directing the County to invalidate LU-1.22 and LU-1.23, PMC timely appealed. The Sixth District Court of Appeal upheld the trial court's finding that section 3106 preempts LU-1.22 and LU-1.23 of Measure Z. The appellate court looked to the text of section 3106 that "identifies the State's *policy* as '*encourag*[*ing*] the wise development of oil and gas resources,' and expressly provides that *the State* will supervise the drilling of oil wells 'so as to *permit*' the use of '*all*' practices that will increase the recovery of oil and gas." *Id.* at 254 (alteration in original) (quoting Cal. Pub. Res. Code § 3106). The court found that section 3106 thereby gives the State authority to permit operators to engage in all methods and practices, and reserves no power over the same to local entities. *Id.*

In upholding the trial court's finding of preemption, the appellate court found that despite its citations to a number of statutes, PMC failed to point to any authority sharing the State's section 3106 powers with local entities. Similarly, PMC's citations to authority affirming that local regulation of oil and gas drilling is within the police power of local entities were not persuasive. "The mere fact that some local regulation of oil and gas drilling is within a local entity's police power does not resolve the question of whether a particular local regulation is *preempted* by a particular state law." *Id.* at 257.

The appellate court further explained that "[a]n accurate characterization of Measure Z's provisions is at the crux of the dispute between PMC and plaintiffs." *Id.* at 258. While PMC argued that Measure Z only purports to regulate whether and where drilling should occur, the court agreed with the trial court that it actually attempts to regulate "the *conduct* of oil and gas operations and specific *production technique*[*s*] rather than the use of land." *Id.* (alteration in original) (internal quotation marks omitted). Measure Z would "ban activities that section 3106 not only promotes and encourages, but also explicitly places the authority to permit in the hands of the State." *Id.* Because it is not possible for the authority to permit certain practices to rest with the State if those practices are forbidden by local ordinance, there is a conflict and "the local ordinance must yield to the supreme state law." *Id.* at 259.

CalGEM Issues New Proposed 3,200-foot Oil Drilling Setback Rules

On October 21, 2021, Governor Gavin Newsom announced that the California Department of Conservation's Geologic Energy Management Division (CalGEM) has released a proposed regulation that would prohibit new oil and natural gas production wells and facilities within a 3,200-foot buffer area (or setback) from homes, schools, hospitals, nursing homes, and other sensitive locations. *See* News Release, Office of Gov'r Gavin Newsom, "California Moves to Prevent New Oil Drilling Near Communities, Expand Health Protections" (Oct. 21, 2021). The regulation would also require pollution controls or mitigation for preexisting wells and facilities that fall within the new 3,200-foot buffer. *Id.* These measures would include systems to detect emissions and leaks and groundwater monitoring. *See* Phil Wilson, "New California Oil Drilling Must Be Set Back from Homes and Schools, Newsom Says," *Los Angeles Times* (Oct. 21, 2021). Wade Crowfoot, Secretary of the California Natural Resources Agency, said the State "anticipate[s] that some producers will choose to safely and permanently seal their well and stop producing as a result of this cost." *Id.*

This is the latest move by the administration in its clean energy efforts, which have included banning the issuance of new hydraulic fracturing permits by 2024, phasing out oil extraction by 2045, and ending the sale of gas-powered cars by 2035. *See id.* Colorado, Pennsylvania, and Texas have setback requirements, but California's would be the largest. *Id.*

Proposals to mandate buffer zones in California have previously failed to pass in the state legislature. *Id.* The proposed regulations thus raise separation of powers questions as to whether the executive branch can ban oil and gas wells in certain locations when the legislature has passed laws encouraging those operations and has not enacted such a ban.

The Western States Petroleum Association (WSPA) issued a statement on October 21, 2021, saying the "true setbacks will be imposed upon California's families, workers and businesses that need affordable, reliable energy every day." WSPA, "WSPA Statement on California Governor's Setback Announcement" (Oct. 21, 2021). WSPA further explained that

> [t]he oil and gas industry is not opposed to setbacks and in fact, has supported many local setbacks that are based on science, data and rigorous health assessments. But this approach by the state will eliminate tax revenues and community benefits, raise costs for everyone and put thousands of people out of work.

Id.

Moving forward, CalGEM will accept public comment on the draft rule, then perform an economic analysis, and then submit the proposed rule to the Office of Administrative Law for an additional comment period. *See* News Release, *supra*. Written comments may be provided through December 21, 2021, and a public workshop to solicit comments will be held on December 1, 2021. The draft rule can be found at https://www.conservation.ca.gov/calgem/Documents/public-health/PHRM%20Draft%20Rule.pdf. If formally adopted, the rule is likely to face legal challenges, including separation of powers claims, takings claims, and claims that the new setback requirement is not based in science and was developed without input from industry experts or dissenting viewpoints. *See, e.g.*, WSPA Statement, *supra*.

WSPA Sues Governor Newsom, CalGEM, and Regulators over De Facto WST Ban After State Rejects Aera's Appeal of WST Permit Denials

As discussed in Vol. XXXVIII, No. 2 (2021) and Vol. XXXVIII, No. 3 (2021) of this *Newsletter*, Governor Gavin Newsom—in furtherance of his September 23, 2020, executive order—on

April 23, 2021, directed the California Department of Conservation's (DOC) Geologic Energy Management Division (CalGEM) to take regulatory action to halt the issuance of new hydraulic fracturing permits by January 2024. CalGEM has since initiated the rulemaking process, and at the same time denied 21 hydraulic fracturing permits to Aera Energy LLC (Aera) for operations in Kern County. *See* Vol. XXXVIII, No. 3 (2021) of this *Newsletter*. In denying the permits, CalGEM cited to "the effects of the climate emergency" and the "risks to everyday Californians," rather than technical deficiencies in the operations, suggesting it was implementing a de facto moratorium on hydraulic fracturing permitting. John Cox, "State Exercises Discretion to Deny Kern Fracking Permits Ahead of Formal Ban," *Bakersfield Californian* (July 9, 2021). In August 2021, the State denied Aera another 14 permits, again citing the State Oil and Gas Supervisor's discretion to deny permit requests to protect the public health and environment. *See* "Calif. Officials Double Down in Kern Co. Standoff, Reject Another Fracking Permit," *San Joaquin Valley Sun* (Aug. 10, 2021).

Aera appealed the denial of the first 21 permits to the DOC on July 16, 2021, asking the Director to set aside CalGEM's orders and approve the 21 permit applications. *See* Notice of Appeal of July 8, 2021 Orders Denying Well Stimulation Treatment Permit Applications, *In re Aera Energy LLC* (July 16, 2021). On August 3, 2021, the State rejected the appeal, saying the denials were not an "order" as defined by the Public Resources Code and so the DOC lacks jurisdiction to hear an appeal. *See* John Cox, "State Rejects Aera's Appeal on Kern Frack Jobs," *Bakersfield Californian* (Aug. 23, 2021).

On the heels of the denial of Aera's appeal, the Western States Petroleum Association (WSPA)—a trade association that includes Aera—filed a lawsuit in Kern County Superior Court against Governor Newsom, State Oil and Gas Supervisor Uduak-Joe Ntuk, CalGEM, and DOC Director David Shabazian challenging the State's "establishment and implementation of a *de facto* moratorium on well stimulation treatments [(WSTs)] . . . ." Verified Complaint for Declaratory and Injunctive Relief, and Petition for Writ of Mandate ¶ 1, *W. States Petroleum Ass'n v. Newsom* (Cal. Super. Ct. Oct. 8, 2021). The complaint notes that CalGEM has not issued a single WST permit in the last six-plus months and asserts that the State's policy of barring WSTs is illegal, arbitrary, capricious, and an abuse of discretion. *Id.* ¶ 5.

Indeed, as asserted in the complaint, the Public Resources Code explicitly authorizes WSTs, *see* Cal. Pub. Res. Code § 3160, and imposes on CalGEM a duty "to encourage the wise development of oil and gas resources" and to "permit the owners and operators of the wells to utilize all methods and practices known to the oil industry for the purpose of increasing the ultimate recovery of underground hydrocarbons." Complaint ¶¶ 2–3 (quoting Cal. Pub. Res. Code §§ 3157, 3106(b), (d), 3150). WSPA argues the de facto ban is causing harm to its members and therefore WSPA's interest is in ensuring that CalGEM issues WST permits in a consistent and timely manner. In short, the complaint pleads that the "No-WST Policy" is illegal and should be declared void as it (1) is contrary to the Public Resources Code, (2) violates the separation of powers doctrine and exceeds the authority of the executive branch, (3) was adopted in violation of the Administrative Procedure Act, and (4) is inconsistent with CalGEM's prior findings that WST operations do not cause harm to human or environmental health and that banning them would lead to greater environmental impacts. *Id.* ¶ 8. Further, it pleads that CalGEM acted arbitrarily and capriciously in issuing denials of WST permits under this policy and for reasons not supported by technical evidence.

Consistent with Aera's appeal of its own denials, the complaint notes that CalGEM denied 21 WST permits in July, 14 in August, and 14 more in September, each time without citing technical evidence of any deficiencies. *Id.* ¶ 48. In fact, according to WSPA, CalGEM staff had recommended issuance of the permits and WSPA believes the denials were at the direction of the Governor under the administration's No-WST Policy. *Id.* ¶ 49.

In a statement on its website, WSPA states:

> CalGEM's decision to deny future permits for WST operations ignores the law and is contrary to all scientific studies and evaluations that have been conducted by CalGEM itself as well as by other independent scientific bodies. Banning WST operations in California will only serve to constrain domestic oil production, resulting in the need to import more oil from foreign sources. Increased imports of foreign oil will also increase global greenhouse gas emissions, further contributing to global warming, contrary to the very goals CalGEM seeks to promote.

WSPA, "WSPA Litigation to Protect Production of Safe, Affordable and Reliable Energy" (Oct. 8, 2021).

Kern County Sues Governor Newsom over "Pattern and Practice" of Delaying and Blocking Oil and Gas Permits in California

Prior to the Western States Petroleum Association (WSPA) lawsuit discussed above, Kern County filed a similar but broader petition for a writ of mandate in Kern County Superior Court on September 13, 2021, in an effort to halt Governor Gavin Newsom's de facto ban on permits for oil and gas operations, including well stimulation treatments (WSTs). Petition for a Writ of Mandate, Prohibition or Other Appropriate Relief (Code of Civil Procedure §§ 1085, 1102) and Declaratory Relief, *Cty. of Kern v. Newsom* (Cal. Super. Ct. Sept. 13, 2021) (County Petition); *see* John Cox, "Kern Sues Newsom over Anti-Oil Moves," *Bakersfield Californian* (Sept. 13, 2021). Unlike WSPA's lawsuit, Kern County names only Governor Newsom as a respondent. The County Petition asserts that under the direction of the Governor, the State has "pursued an unmistakable pattern and practice of impeding, delaying and/or outright blocking the issuance of oil and gas permits in a manner that thwarts existing law and implements substitute policies never approved by the duly elected California State Legislature . . . ." County Petition ¶ 6. More specifically, the County asserts three causes of action: (1) violation of separation of powers; (2) violation of the Administrative Procedure Act (APA); and (3) declaratory relief, seeking a declaration that the Governor's directives and executive orders and the California Department of Conservation's Geologic Energy Management Division's (CalGEM) actions in response to those directives are violations of the California Constitution, exceed their statutory powers, are arbitrary and capricious, and violate the APA.

Like the WSPA lawsuit, the County Petition calls out the Governor's de facto ban on WST permits in California, noting that CalGEM approved a dozen WST permits in the first two months of 2021, but denied 21 others and has since approved none. *Id.* ¶ 42. But the County Petition goes beyond WST permit denials, asserting that the Governor and CalGEM have also imposed a statewide moratorium on high pressure cyclic steam injection (HPCS), *id.* ¶ 45, an illegal plan to "end oil extraction in our state," *id.* ¶ 48, and an illegal delay in the processing of routine well permits, *id.* ¶ 51. The County Petition discusses the economic harm suffered by the county, the environmental harm to the county and the state as a whole, and the strategic harm to California and the Nation. *Id.* ¶¶ 52–57.

The County seeks a writ of mandate directing the respondents "to cease and desist any and all actions . . . undertaken to carry out Newsom's directive" to: (1) ban WST, HPCS, and similar technologies; (2) ban or place a moratorium on processing or granting such permits; (3) delay or frustrate CalGEM's processing of permits; (4) impose arbitrary administrative roadblocks to hinder the processing of permits; (5) circumvent the APA; and (6) otherwise carry out the Governor's directive to expedite the closure and remediation of oil extraction sites and end oil extraction in the state. The County further seeks (1) a writ of prohibition prohibiting the Governor from issuing further unlawful orders, (2) a decree that CalGEM has violated the APA by enforcing new rules to delay the processing and granting of permits and declaring CalGEM's non-APA compliant rules null and void ab initio, and (3) a writ requiring CalGEM to resume processing and approving permits in accordance with its APA-compliant rules. Finally, the County seeks a declaration that the Governor does not have the power to direct CalGEM not to process or approve permit applications or otherwise alter CalGEM's requirements for processing and approving applications, and seeks a decree that all executive orders or instructions purporting to impose a moratorium or to expedite the closure of oil extraction sites are void.

Revised Kern County Oil and Gas Permitting Ordinance Successfully Challenged

In the ongoing battle over Kern County's oil and gas permitting ordinance, the Kern County Superior Court on October 4, 2021, issued a ruling granting in large part the petitioners' joint motion to enforce the second peremptory writ of mandate. Ruling on Petitioners' Joint Motion to Enforce Second Peremptory Writ of Mandate, *Vaquero Energy v. Cty. of Kern*, No. BCV-15-101645 (Cal. Super. Ct. Oct. 4, 2021).

For background, and as discussed in more detail in Vol. XXXVII, No. 2 (2020) of this *Newsletter*, the California Court of Appeal for the Fifth District issued a ruling last year setting aside the County's oil and gas permitting ordinance (2015 Ordinance) after identifying multiple deficiencies in the environmental review process. *See King & Gardiner Farms, LLC v. Cty. of Kern*, 259 Cal. Rptr. 3d 109 (Ct. App. 2020). To correct those deficiencies, the County Board of Supervisors (Board) ultimately certified a supplemental recirculated environmental impact report (SREIR) and approved adoption of a revised ordinance, which became effective April 7, 2021 (2021 Ordinance). Kern County Code of Ordinances § 19.98.010. A number of petitioners thereafter filed a lawsuit in Kern County Superior Court challenging the 2021 Ordinance and the underlying SREIR. *See* Verified Petition for Writ of Mandate and Complaint for Injunctive Relief, *Comm. for a Better Arvin v. Cty. of Kern* (Cal. Super. Ct. Mar. 10, 2021); *see also* Vol. XXXVIII, No. 2 (2021) of this *Newsletter* (discussing the lawsuit and relevant background). Therein, the petitioners asked the court to decline to discharge the writ of mandate concerning the 2015 Ordinance and related environmental impact report until the County fully complied with the California Environmental Quality Act (CEQA), Cal. Pub. Res. Code §§ 21000–21189.57, with respect to the 2021 Ordinance.

The court has consolidated all pending related actions, including the ongoing 2015 action and the 2021 action. Most recently, by way of a joint motion, the petitioners asserted that the County has circumvented the second peremptory writ of mandate by issuing oil and gas permits under the 2021 Ordinance without first obtaining a judicial discharge of the writ. The County argued that it had made its own determination that it had complied with the CEQA requirements of the writ, and that a judicial discharge was not required.

On October 4, 2021, the court issued a ruling finding that a judicial determination as to whether a writ has been satisfied is required under Cal. Pub. Res. Code § 21168.9(b), and so—because there was no such discharge—the 2021 Ordinance "must be set aside as inoperable until a judicial determination is made that the ordinance satisfies the CEQA requirements of the Second Peremptory Writ of Mandate." Ruling on Petitioners' Joint Motion at 2.

The petitioners additionally sought to have the court invalidate all permits previously issued under the 2021 Ordinance. Because the 2021 Ordinance was adopted in an open process that included participation from interested parties (including the petitioners), and because the County would be prejudiced in the form of logistical and economic harm by the petitioners' failure to act sooner, the court declined to invalidate existing permits and instead limited its ruling to a ban on prospective permits only. *Id.* The County has thus been ordered to "immediately suspend operation of the [2021 Ordinance] and to cease reviewing and approving oil and gas permits under said ordinance, until and unless" the court determines that the 2021 Ordinance complies with the CEQA requirements of the writ and discharges the writ. *Id.* Trial on the matter is set for April 28, 2022.

Shortly after the ruling came out, on October 7, 2021, the County issued a letter to interested parties explaining how it will handle permitting and existing applications in light of the court's order. Letter from Kern Cty., to Interested Oil and Gas Operators and Companies (Oct. 7, 2021). Therein, the County says it stopped permitting at 3:00 p.m. on October 6 when it received the order. *Id.*

The court order did not address how the California Department of Conservation's Geologic Energy Management Division (CalGEM), as a responsible agency under CEQA, should proceed when reviewing notices of intent (NOIs) and applications for operations in Kern County under the 2021 Ordinance. On November 2, 2021, CalGEM issued a notice to operators (NTO) that clarifies how CalGEM intends to proceed on pending Kern County NOIs and applications submitted before 3:00 p.m. on October 6 under the 2021 Ordinance. NTO 2021-06, "Documenting CEQA Compliance for Proposed Operations in Kern County" (Nov. 2, 2021). Specifically, the NTO provides direction for operators who fall into one of three groups:

(1) For NOIs and applications submitted to CalGEM with a job card issued by the County under the 2021 Ordinance, CalGEM will continue its CEQA review as a Responsible Agency under CEQA, but any approval thereof will be conditional, meaning the operator may proceed only as long as the court finds the SREIR complies with CEQA. As a result, an operator may not proceed with operations until the required court order is issued.

(2) Operators who submit an NOI or application without a job card from the County will have CalGEM as the acting Lead Agency for purposes of conducting CEQA review.

(3) Operators who submitted an NOI or application with a job card from Kern County issued between April 7 and 3:00 p.m. on October 6, 2021, may withdraw if they do not want a conditional permit. They may resubmit the application or NOI without a job card, in which case

CalGEM will act as the Lead Agency, per paragraph (2) above.

Id.

EPA Letter to CalGEM Urges Class II UIC Program Compliance

On September 16, 2021, the U.S. Environmental Protection Agency (EPA) wrote to the California Natural Resources Agency (CNRA)—the parent agency over the Department of Conservation (DOC), of which the Geologic Energy Management Division (CalGEM) is a part—and the California State Water Resources Control Board (SWRCB) to "express serious concern with California's pace in fulfilling its obligations . . . to return the Class II Underground Injection Control (UIC) program to full compliance with the Safe Drinking Water Act (SDWA)." Letter from Tomas Torres, Dir., Water Div., EPA, to Matt Kaber, Deputy Sec'y for Energy, CNRA, and Eileen Sobeck, Exec. Dir., SWRCB (Sept. 16, 2021). EPA noted that while 21 of 30 expected aquifer exemption proposals have been processed, too many wells continue to inject into unauthorized aquifers. *Id.*

The letter provides that if the State "continue[s] to demonstrate an inability to fully return the Class II UIC program to compliance, EPA will consider limiting the State's UIC program expansion to cover other types of injection, including Class VI geologic carbon sequestration." *Id.* EPA may consider other punitive measures as well, including placing conditions on the State's Class II UIC primacy grant, withholding funding, enforcement for noncompliance, and orders to noncompliant operators. *Id.*

The State was given 30 days to deliver a revised schedule for submitting all aquifer exemption packages to EPA by September 30, 2022. Alternatively, the State can inform EPA of the steps it intends to take to stop injection into unauthorized aquifers until EPA has reviewed and acted on all outstanding aquifer exemption packages. *Id.*

On October 15, 2021, CalGEM and the SWRCB responded to EPA's letter by explaining that three of the remaining nine aquifer exemption applications will be submitted to EPA by the September 30, 2022, deadline. Letter from David Shabazian, Dir., DOC, and Eileen Sobeck, Exec. Dir., SWRBC, to Tomas Torres, Dir., Water Div., EPA (Oct. 15, 2021). The other six applications will need to undergo additional well integrity evaluations (conduit reviews). *Id.* For those six applications, the conduit reviews will be completed, and any problem wells located within active injection areas will be identified, by the September 30, 2022, deadline. *Id.* By that same date, operator specific work plans approved by the State will be required after the completion of each conduit review to address problem wells or the wells will be shut in. *Id.* The State also will provide an updated schedule for completing the six application packages as soon as the conduit analysis scoping is complete, but no later than December 31, 2021. *Id.*

COLORADO – OIL & GAS

Sarah Sorum & Kate Mailliard
– Reporters –

Adams County, City and County of Broomfield, and Larimer County Adopt New Well Setbacks Under Senate Bill 19-181

In late July and early August 2021, the Adams County Board of County Commissioners, the Larimer County Board of County Commissioners, and the Broomfield City Council all adopted new well setback regulations pursuant to Senate Bill 19-181, which gave local governments more regulatory authority over oil and gas drilling and directed the Colorado Oil and Gas Conservation Commission (COGCC) to revise statewide regulations to prioritize health and safety.

In Adams County, new regulations increase setback distances for new oil and gas drilling to 2,000 feet from homes, schools, state licensed daycares, high occupancy building units, environmentally sensitive areas, parks, and open spaces. Adams County Development Standards and Regulations § 4-11-02-03-03-03(4) (amended July 27, 2021). Adams County has also established a 1,000-foot setback from groundwater under the direct influence of surface water wells and from Type III Aquifer wells, as defined by the COGCC rules. *Id.*

Broomfield's new regulations require 2,000-foot setbacks of pre-production oil and gas facilities from athletic fields, amphitheaters, auditoriums, childcare facilities, correctional facilities, dwelling units, event centers, hospitals, life care institutions, nursing homes and nursing facilities, recreational facilities, schools and school facilities, and undeveloped residential lots. Broomfield Municipal Code § 17-54-070(C) (amended by Ordinance No. 2144, May 11, 2021). Those facilities may not be located closer than 2,000 feet from an oil and gas location that is in the construction, drilling, or completion phase. *Id.* § 17-54-080 (amended by Ordinance No. 2144, May 11, 2021). For producing wells, the established residential setback of 200 feet for all development and 1,320 feet without notice for development after 2019 will continue to apply. *Id.* § 16-28-180 (amended by Ordinance No. 2156, July 28, 2021). Since 1995, the Broomfield Municipal Code has restricted residential units from being built within 200 feet of an existing oil and gas facility and has restricted schools from being located within 500 feet of an oil and gas facility. *See* Brooklyn Dance, "Broomfield City Council OKs 2,000-Foot Reverse Setbacks from Pre-Production Oil and Gas Sites," *Daily Camera* (July 28, 2021).

Larimer County has also adopted new setback regulations that require oil and gas well sites and production facilities to be located at least 2,000 feet from the property line of any school, hospital or medical clinic, senior living or assisted living facility, multi-family dwelling, or state-licensed day care. Larimer County Land Use Code § 11.3.2(B) (effective Sept. 15, 2021). For residential homes, setbacks start at 2,000 feet and can go down to 1,000 feet. *Id.* § 11.3.2(D). Unless approved by the Larimer County Board of County Commissioners through a special review process, oil and gas facilities must also be at least 2,000 feet from (1) publicly maintained trails and trailheads, community park lands, public parks, and regional parks; (2) public water supply intakes or public water supply wells; and (3) building units that are not subject to a waiver from all unit owners and tenants specifically agreeing to a proposed oil and gas facility location. *Id.* § 11.3.2(C).

LOUISIANA – OIL & GAS

Kathryn Gonski, Cristian Soler & Court VanTassell
– Reporters –

Louisiana First Circuit Applies Subsequent Purchaser Doctrine to Property Transfer Involving Closely Held LLC

In *Louisiana Wetlands, LLC v. Energen Resources Corp.*, 2021-0290 (La. App. 1 Cir. 10/4/21); 2021 WL 4548529, the Louisiana First Circuit Court of Appeal addressed for the first time whether the subsequent purchaser doctrine barred a claim brought by a closely held or family-owned company that acquired the property in an intra-family transfer.

Louisiana Wetlands involved a 300-acre tract of land that had been owned by the family of James J. Bailey, III and passed down from generation to generation for over a century. In 2009, certain members of the Bailey family formed New 90, LLC (New 90), a limited liability company (LLC), to manage this tract and other property they owned. After creating New 90, the individual Bailey family owners executed an "Act of Transfer" that transferred their interests in the property to New 90 in exchange for membership interests in the LLC. The Act of Transfer included the following pertinent provisions: (1) the transferors desired that New 90 "own, operate, develop and manage" the property; (2) "in consideration of the premises, and for certain other good and valuable consideration" the transferors "GRANT, BARGAIN, SELL, TRANSFER AND CONVEY" to New 90 "all and singular the whole of all right, title, interest, and ownership" of the property; and (3) the property was transferred to New 90 "with full and general warranty of title, and with full subrogation to all rights of warranty and all other rights as held therein by said vendor." *Id.* at *1.

In December 2016, New 90 and another plaintiff-landowner sued various oil and gas companies for alleged contamination to the property based on historical exploration and production activities dating back to the 1940s. The defendants moved for summary judgment based on the subsequent purchaser doctrine, claiming that New 90 had no right to bring a claim for alleged property damage that occurred before New 90 acquired the property in 2009. The trial court agreed and dismissed all of New 90's claims. *Id.* at *2.

On appeal, New 90 argued that the subsequent purchaser doctrine applies only to transactions involving an arm's-length sale of property, not to transfers of property from family members to an LLC in exchange for an ownership interest in the company. *Id.* New 90 also argued that the trial court erred in finding that the "all rights" language in the Act of Transfer did not include the personal right to sue for property damage. *Id.* The First Circuit began its opinion by turning to the "comprehensive analysis" of Louisiana property law and the subsequent purchaser doctrine in *Eagle Pipe & Supply, Inc. v. Amerada Hess Corp.*, 2010-2267 (La. 10/25/11); 79 So. 3d 246. *La. Wetlands*, 2021 WL 4548529, at *3. There, the Louisiana Supreme Court held that the right to sue for pre-acquisition property damage is a personal right that belongs to the person who owned the property when the damage occurred, and this personal right does not transfer to a subsequent owner absent an express assignment or subrogation of that right from the previous owner. *Id.*

Following *Eagle Pipe*, the First Circuit found that the subsequent purchaser doctrine applied to New 90's scenario and held that "it is immaterial how property is transferred to a particular successor. If the transferring instrument does not contain an explicit assignment of the personal right to sue for damage to the property, that right remains with the transferor." *Id.* The First Circuit then found that the Act of Transfer did not expressly or specifically assign the right to sue for pre-acquisition damages to New 90 because the Act did not mention the personal right to sue for pre-acquisition damages, the right to seek restoration of the property, or any of the mineral leases that previously covered the property. *Id.*

Editor's Note: The reporters' law firm represented defendant BP America Production Company.

Louisiana Supreme Court Grants Rehearing in Act 312 Legacy Lawsuit

The Louisiana Supreme Court recently granted rehearing for further briefing and argument with respect to its June 30, 2021, ruling in *State v. Louisiana Land & Exploration Co.* (*LL&E II*), 2020-00685 (La. 6/30/2021); 2021 WL 2678913. *See* Vol. XXXVIII, No. 3 (2021) of this *Newsletter*.

In *LL&E II*, the court revisited its ruling in *State v. Louisiana Land & Exploration Co.* (*LL&E I*), 2012-0884 (La. 1/30/13); 110 So. 3d 1038, in which it held that, even without an express contractual provision, defendants who operated unreasonably had an *implied* obligation under the Mineral Code to restore property above and beyond regulatory environmental standards. *See* La. Stat. Ann. § 30:29 (2006) (Act 312). *LL&E I* further determined that these "excess remediation damages" were awards landowners could keep for themselves under Act 312.

In *LL&E II*, the court held that:

> (1) outside of an express contractual provision, Act 312 does not allow for remediation damages in excess of those required to fund the court adopted remediation plan; (2) the plan is left to the sole judgment of the trial court itself, not the jury; and therefore, (3) Act 312 provides no intent for the jury to decide the amount of remediation damages that meet Act 312 compliance. Act 312 only allows the jury to award excess remediation damages when an express contractual provision providing for such an award exist[s]. Outside of any express contractual provision being present, it is error to have the jury consider any damages related to Act 312 remediation of the property. The jury's sole role is to consider liability and damages for private causes of action, as well as for contractual causes of action where an express provision allows for remediation and damages in excess of governmental standards.

2021 WL 2678913, at *7.

LL&E II also held that the trial court was not "manifestly erroneous or clearly wrong in overruling the [defendant's] exception of prescription." *Id.* at *4. The court stated that the act of hiring an attorney was not "dispositive proof of the party's knowledge of the injury," but only "evidence . . . which a trial court considers when making a factual determination of when a party had actual or constructive knowledge of their injury." *Id.*

Both parties sought rehearing. The plaintiff argued primarily that Act 312 is unconstitutional if it caps the amount of damages that are available on a breach of contract claim and sought clarification as to how the ruling applies to the current version of Act 312. The defendant sought rehearing primarily with respect to the prescription ruling.

While the Louisiana Supreme Court granted rehearing for further briefing and argument, it did not specify which grounds it wanted to reconsider.

Louisiana Supreme Court Grants Writ Application from First Circuit Decision Involving Citizen Suit Claim

On October 19, 2021, the Louisiana Supreme Court granted the writ application of defendants BOPCO, LLC (f/k/a BOPCO, L.P.), Chisholm Trail Ventures, L.P., and BEPCO, L.P. from the Louisiana First Circuit Court of Appeal decision in *State ex rel. Tureau v. BEPCO, L.P.*, 2021-0080 (La. App. 1 Cir. 5/19/21); 2021 WL 1997498. The defendants sought review of the First Circuit's holding that actions brought pursuant to La. Stat. Ann. § 30:16 are not subject to the one-year liberative prescriptive period for delictual actions.

This lawsuit involved allegations of property contamination and violations of Statewide Order 29-B resulting from the defendants' historical oil and gas exploration and production activities. The First Circuit was tasked with analyzing the plaintiff's appeal of the trial court's judgment, which dismissed the plaintiff's claims as prescribed for the following reasons: (1) the State of Louisiana was not the real party in interest, thus the State's prescription immunity and the continuing tort doctrine did not apply; and (2) the one-year prescriptive period applied.

The First Circuit began by characterizing the plaintiff's action as one for injunctive relief pursuant to section 30:16 and noting that the legislature has not enacted a specific liberative prescription statute applicable to section 30:16 claims. *BEPCO*, 2021 WL 1997498, at *4. Next, the court distinguished the multitude of cases relied upon by the defendants where the one-year, delictual action prescriptive period was applied to actions involving environmental damage to property. *Id.* at *5. The court recognized that each of the defendants' cited cases involved claims for damages, and therefore, such claims were properly characterized as delictual and the one-year period applied. *Id.* However, in the instant suit, the court reasoned that the plaintiff was not seeking to recover any damages for alleged environmental damage; rather, the plaintiff was pursuing injunctive relief and the administrative enforcement of Statewide Order 29-B. *Id.*

Next, the court discussed the promulgation of Statewide Order 29-B, the statutory scheme of La. Stat. Ann. §§ 30:14 and 30:16, the Commissioner of Conservation's role in enjoining violations of conservation law, and the ability of a person "adversely affected" by such violations to file suit under section 30:16 if the Commissioner fails to act. *BEPCO*, 2021 WL 1997498, at *5. The statutory scheme whereby a person can initiate administrative suits, bolstered by language from the Louisiana Supreme Court in *Marin v. Exxon Mobil Corp.*, 2009-2368 (La. 10/19/10); 48 So. 3d 234, and *Eagle Pipe & Supply, Inc. v. Amerada Hess Corp.*, 2010-2267 (La. 10/25/11); 79 So. 3d 246, led the court to its conclusion that the plaintiff's claims for injunction and administrative enforcement of Statewide Order 29-B are not subject to the one-year liberative prescription period applicable to delictual actions, and the district court erred in concluding otherwise. *BEPCO*, 2021 WL 1997498, at *6. The court noted, however, that its decision held only that the plaintiff's claims were not subject to the one-year prescriptive period applicable to delictual actions. *Id.* at *6 n.4. The court "express[ed] no opinion as to what liberative prescription period, if any, is applicable." *Id.*

The Louisiana Supreme Court granted writs for further briefing and argument, and its resulting decision is likely to have significant impact on the recent trend of citizen suit claims brought pursuant to section 30:16.

Editor's Note: The reporters' law firm represented defendant BOPCO, LLC.

Louisiana Allowed to Intervene in Drilling Lease Auction Lawsuit

On September 22, 2021, the U.S. District Court for the District of Columbia authorized Louisiana Attorney General Jeff Landry to intervene in a lawsuit filed by Friends of the Earth and other environmental advocates. *See Friends of the Earth v. Haaland*, No. 1:21-cv-02317 (D.D.C. filed Aug. 31, 2021). Louisiana will join the case as a defendant alongside the U.S. Department of the Interior.

After the Biden administration announced its plan to comply with a court order requiring it to resume lease auctions, the plaintiffs filed suit to block the federal government from holding a lease sale that would offer the majority of all available, unleased blocks in a more than 90-million-acre area in the Gulf of Mexico. The plaintiffs principally argue that the planned sale violates the National Environmental Policy Act because its authorization relies on a flawed and outdated analysis of its environmental impacts.

The plaintiffs opposed Louisiana's proposed intervention, but the district court agreed to the request, in part due to sufficient doubts that Louisiana's interests would be adequately represented by the federal government.

NEVADA – MINING

Thomas P. Erwin
– Reporter –

Legislature Approves Business Excise Tax That Covers Gross Revenue from the Sale of Minerals

The Nevada Legislature considered and approved a business excise tax that applies to the gross revenue of business entities. *See* Assembly Bill 495 (AB 495), 2021 Nevada Laws ch. 249 (effective July 1, 2021). AB 495 expressly provides that taxable gross revenue includes revenue from the sale of gold and silver produced in Nevada.

AB 495 applies to gross revenue from the sale of gold and silver from mines in Nevada. *Id.* §§ 25, 27(1)(d). Gross revenue from the sale of minerals other than gold and silver is not included in the determination of taxable gross revenue. *Id.* § 26(3). AB 495 also applies to royalties from real property in Nevada. *Id.* § 27(1)(a). Under Nevada law, mining claims and mineral rights are real property.

AB 495 provides that the excise tax is imposed on each business entity whose gross income meets a $20 million gross revenue threshold. The rate of the excise tax is 0.75% of gross revenue in excess of $20 million and up to $150 million and 1.10% of gross revenue in excess of $150 million. *Id.* § 25(1). AB 495 excepts certain types of businesses from the definition of "business entity." It provides that an entity is not a business entity if it is a passive entity. *Id.* § 4(2)(*l*).

An entity that receives mineral royalties from the production of minerals in Nevada may qualify as a passive entity. AB 495 defines "passive entity" as an entity that (1) is a flow-through entity such as a limited liability company, partnership, or limited partnership; (2) derives 90% or more of its federal gross income from royalties from mineral properties; and (3) does not derive more than 10% of its federal gross income from the conduct of an active trade or business (which under AB 495 § 21(3)(b) does not include mere ownership of mineral royalties). *Id.* § 21(1). Apparently, an individual who receives mineral royalties that are reported on Schedule C (business income or loss) or Schedule E (rents and royalties) of the individual's federal income tax return is not excepted from the definition of business entity. *Id.* § 4(2)(b).

For purposes of the net proceeds of minerals tax, Nev. Rev. Stat. § 362.105 defines a royalty as a portion of the proceeds from the extraction of a mineral that is paid for the privilege of extracting the mineral. Because under Nevada law the legislature is deemed to have enacted AB 495 with knowledge of section 362.105, this definition of royalty will govern the determination of a business entity's federal gross income from royalties on mineral properties under AB 495 § 21(1)(b).

Legislature Denies Exploration and Mining Operation Permits to "Bad Actors"

Assembly Bill 148 (AB 148), 2021 Nev. Laws ch. 385 (effective Apr. 1, 2022), amends Nev. Rev. Stat. ch. 519A to limit the ability to obtain an exploration permit under Nev. Rev. Stat. § 519A.190 or a mining operation permit under Nev. Rev. Stat. § 519A.210 from the Nevada Division of Environmental Protection (NDEP) if the permit applicant, or each person who has a controlling interest in the permit applicant (if the applicant is a business entity), has either (1) defaulted on a reclamation obligation under chapter 519A, or (2) is otherwise not in good standing with a government agency in relation to reclamation of an exploration project or mining operation situated outside the state of Nevada.

AB 148 amended section 519A.190(1), which now requires that an applicant seeking an NDEP exploration permit include the following in or with the application: (1) if the applicant is a business entity, the names and addresses of each person who has a controlling interest in the business entity; and (2) "[a]n affidavit stating whether or not the applicant and, if applicable, each person who has a controlling interest in the [business entity applicant] is in good standing with all agencies of other states and federal agencies in relation to the reclamation of exploration projects outside of [the state of Nevada]." Nev. Rev. Stat. § 519A.190(1)(a) (effective Apr. 1, 2022).

Newly enacted section 519A.190(2) prohibits NDEP from issuing a permit to engage in an exploration project to (1) any applicant who has defaulted on any reclamation obligation under chapter 519A (including by forfeiting a surety or failing to pay the costs or penalties associated with reclamation); (2) any business entity applicant if any person who has a controlling interest in the applicant has, or previously had, a controlling interest in another business entity that defaulted on any obligation relating to reclamation pursuant to chapter 519A; or (3) an applicant if the applicant, or any person who has a controlling interest in the applicant (if applicable), "is not in good standing with an agency of another state or a federal agency in relation to the reclamation of an exploration project outside of [the state of Nevada]." *Id.* § 519A.190(2) (effective Apr. 1, 2022).

For applicants who fall under any of these three categories, NDEP may still issue an exploration permit to the applicant provided the conditions of sections 519A.190(3) or (4), as applicable, are met. Under section 519A.190(3), NDEP may issue an exploration permit to those applicants who have previously defaulted on any reclamation obligation under chapter 519A provided (1) the applicant has either cured, or has provided evidence of satisfaction of, the defaulted reclamation obligation; and (2) the applicant has provided evidence that the conditions leading to the default have been remedied such that the conditions no longer exist. *Id.* § 519A.190(3) (effective Apr. 1, 2022). Section 519A.190(4) provides that NDEP may issue an exploration permit to those applicants who are not in good standing with a government agency in connection with an out-of-state exploration project if the applicant is able to demonstrate that it has remedied all reclamation issues for the project and that it is now in good standing with such government agencies. *Id.* § 519A.190(4) (effective Apr. 1, 2022).

Nev. Rev. Stat. § 0.039 defines a "person" as a natural person and any form of business organization (including, but not limited to, a corporation, partnership, trust, association, or unincorporated organization). Under the new section 519A.190(5), the term "person who has a controlling interest" is defined to include (1) the president, secretary, treasurer, or equivalent thereof of the business entity; (2) a partner, director, or trustee of the business entity; or (3) a person who, directly or indirectly, possesses the power to direct the management or determine the policy of the business entity based on his or her ownership of voting stock, a contract, or any other circumstance. *Id.* § 519A.190(5) (effective Apr. 1, 2022).

AB 148 amended section 519A.210 to create and impose the same obligations, requirements, and restrictions as that of the amendment to section 519A.190 (as described above), except as it relates to obtaining an NDEP permit for the engagement in a mining operation.

Nevada Supreme Court Upholds Adverse Possession of Patented Mining Claims

In *National Gold Mining Corp. v. Hygrade Gold Co.*, 489 P.3d 915 (Table), 2021 WL 2769037 (Nev. 2021) (unpublished), the Nevada Supreme Court considered the requirements for a claim of adverse possession of a cotenancy interest in patented mining claims. The case arose from a series of conveyances among a dissolved corporation, its shareholders (who were siblings) to whom the corporation conveyed the mining claims, and the successors-in-interest of the shareholders. The plaintiff filed an action for quiet title. The defendant filed a counterclaim to quiet title. Following a bench trial, the district court entered judgment for the defendant finding that the defendant had proven adverse possession by the defendant and its predecessors-in-interest for the statutory period of time.

The supreme court cited Nev. Rev. Stat. § 40.090(1), which provides that a party may bring a quiet title action if the party adversely possessed the land for 15 or more years and paid all taxes against the property for five years preceding the filing of the action. *Nat'l Gold*, 2021 WL 2769037, at *2. The court held that "the adverse possessor must show that 'the occupation of the property is "hostile, actual, peaceable, open, notorious, continuous and uninterrupted"' for the statutory period," *id.* (quoting *Triplett v. David H. Fulstone Co.*, 849 P.2d 334, 336 (Nev. 1993)), and that the possession was exclusive, *id.* (citing *O'Banion v. Simpson*, 191 P. 1083, 1088 (Nev. 1920)).

The supreme court held that in the case of adverse possession of a cotenant, "the adverse possessor must oust the cotenant to satisfy the hostility requirement." *Id.* at *3 (citing *Lanigir v. Arden*, 409 P.2d 891, 895 (Nev. 1966)). The court additionally held that when the cotenants are siblings "the adverse possessor must 'openly disavow the claims of [the other siblings], and unequivocally make [the] claim of sole ownership known to them.'" *Id.* (quoting *Lanigir*, 409 P.2d at 895).

The supreme court found that the defendant's predecessors-in-interest, a shareholder of the dissolved corporation and his wife, openly and unequivocally disclaimed the interest of the shareholder's brother, who was also a shareholder of the dissolved corporation. *Id.* They did so by recording an affidavit that asserted their ownership of the mining claims by adverse possession and by recording a deed to themselves of title to the mining claims. *Id.*

The plaintiff asserted that the possession by the defendant and its predecessors-in-interest was not hostile and exclusive because the plaintiff's predecessors-in-interest were allowed to visit the mining claims. The supreme court rejected this contention, holding that "sporadic use, temporary presence, or permissive visits by others, including the record owner, will not defeat the exclusive element." *Id.* at *4 (quoting *Nutting v. Reis*, 326 S.W.3d 127, 130 (Mo. Ct. App. 2010)). The supreme court affirmed the district court's factual finding that the visits were permissive. *Id.*

OHIO – MINING / OIL & GAS

J. Richard Emens, Sean Jacobs & Cody Smith
– Reporters –

Ohio Appellate Court Limits Search Efforts Required to Locate Adverse Claimants to Mineral Interest Prior to Publishing Notice

In *4 Quarters, LLC v. Hunter*, 2021-Ohio-3586 (7th Dist.), the Ohio Seventh District Court of Appeals further clarified the amount of reasonable diligence required prior to publishing notice of a complaint pursuant to Ohio Rule of Civil Procedure 4.4.

4 Quarters involved competing claims of ownership to oil and gas underlying 78.9 acres in York Township, Belmont County, Ohio. In 1922, C.H. and Edna McCleery Hunter conveyed the property to Edward and Mary C. Carpenter. The deed contained a reservation of one-half of the oil and gas under the property. On August 2, 2019, 4 Quarters, LLC (4 Quarters) obtained the surface right to the property and filed a complaint three days later seeking to have the oil and gas quieted in its name pursuant to the Ohio Marketable Title Act, Ohio Rev. Code §§ 5301.47–.55. 4 Quarters filed a motion to serve the complaint to any unknown Hunter heirs by publication pursuant to Ohio Rule of Civil Procedure 4.4. The motion was granted and, on October 11, 2019, default judgment was granted against the unknown heirs. *4 Quarters*, 2021-Ohio-3586, ¶¶ 1–3.

Carl Hunter Rubel, the appellee, claimed that he was the sole heir of the Hunters. However, he did not appear in the lawsuit until July 21, 2020, when he filed a motion to vacate the default judgment entry pursuant to Ohio Rule of Civil Procedure 60(B). Rubel claimed in part that 4 Quarters failed to exercise reasonable diligence in attempting to locate him prior to publishing notice of the complaint. Rubel claimed 4 Quarters failed to exercise reasonable diligence because it failed to look for his address in the records of Marshall County, West Virginia—where the 1922 deed between the Hunters and the Carpenters was notarized. *Id.* ¶¶ 4–6. In a response to a motion for relief from judgment, Rubel claimed that online records of Marshall County would have shown at least two marriage certificates and the death records for C.H. Hunter and these documents *may* have identified Hunter heirs. However, Rubel failed to disclose what the records *actually* provided. *Id.* ¶ 22.

The Seventh District, however, found that "[a]t best, the location [where] the deed was notarized, without more, provides information about the person notarizing the document, not the Hunters." *Id.* ¶ 30. The court noted that even if the Marshall County records were searched, Rubel failed to show that it would have led 4 Quarters to find him when he has a different last name and lives in a different state—Florida. *Id.* ¶ 23. The court then distinguished its prior holdings in *Fonzi v. Miller*, 2020-Ohio-3739, 155 N.E.3d 986 (7th Dist.), *appeal docketed*, 2020-Ohio-4574, 153 N.E.3d 105 (Table), and *Fonzi v. Brown*, 2020-Ohio-3631 (7th Dist.), *appeal docketed*, 2020-Ohio-4232, 151 N.E.3d 634 (Table), which involved deeds that specifically stated the county and state in which a holder of the oil and gas lived. *4 Quarters*, 2021-Ohio-3586, ¶¶ 27–30; *see* Vol. XXXVII, No. 3 (2020) of this *Newsletter*. Thus, the court affirmed the finding of default judgment against Rubel. *4 Quarters*, 2021-Ohio-3586, ¶ 32.

4 Quarters is the latest decision interpreting the reasonable diligence standard of Ohio Rule of Civil Procedure 4.4. While the decision only relates to a procedural rule, it is important because the Seventh District drew parallels between the rule and the reasonable diligence standard of the Ohio Dormant Mineral Act, Ohio Rev. Code § 5301.56. "[W]hether a search is reasonable will depend on the facts and circumstances of each case." *4 Quarters*, 2021-Ohio-3586, ¶ 14. However, *4 Quarters* provides some indication that the reference to another state in a notary block may not require additional searches if there is no link between the location and the claimant.

OKLAHOMA – OIL & GAS

James C.T. Hardwick
– Reporter –

Amendments Adding Additional Lien Coverage to Oil and Gas Owners' Lien Act of 2010

It is no surprise that bankruptcy in the oil and gas industry is sometimes responsible for legislation to address bankruptcy outcomes that are considered to be unfair to some segment of the industry. For example, see the *SemCrude* bankruptcy where the consequences highlighted that Oklahoma's existing Oil and Gas Owners' Lien Act of 1988 (1988 Lien Act) was inadequate to protect royalty owners and working interest owners entitled to unpaid production sales proceeds from an intervening bankruptcy of the first purchaser of production before payment of proceeds to the rightful owners was made. *Samson Res. Co. v. SemCrude, L.P.* (*In re SemCrude, L.P.*), 407 B.R. 140 (Bankr. D. Del. 2009). The *SemCrude* decision resulted in the repeal of the 1988 Lien Act and the enactment of the Oil and Gas Owners' Lien Act of 2010 (2010 Lien Act), Okla. Stat. tit. 52, §§ 549.1–.12, which is a complete replacement of the 1988 Lien Act. Under the 2010 Lien Act, persons entitled to proceeds of production are given a lien to secure the obligations of a first purchaser to pay the sales price. *Id.* § 549.3. Unlike the 1988 Lien Act, the 2010 Lien Act does not require a filing or other act by the beneficiary of the lien to accomplish perfection. Perfection is conferred by statute as a matter of law. The lien is part of the rights inherent in ownership of the oil and gas in place and extends *pro tanto* into and with the various iterations that oil and gas ownership may take en route to a first sale. Further, the lien takes priority over all other liens, whether arising by contract, law, equity, or otherwise. *Id.* § 549.7. The only exceptions are certain mortgages that predate the effective date of the 2010 Lien Act and meet certain narrow criteria, and certain governmental liens for storage or transportation charges.

Fast-forward to the recent round of bankruptcies. A common device employed to deal with recalcitrant unleased mineral and working interest owners that do not wish to participate in the drilling of a well by paying their share of costs and expenses is force pooling. Employment of force pooling typically results in a pooling order from the Oklahoma Corporation Commission (OCC) requiring the respondents that are unwilling to pay the costs and expenses of participating in the well to elect to accept one of two or more alternatives, which will result in the respondents relinquishing their working interest rights to the operator and, depending upon the election made, also requiring the operator to pay to the electing respondents a per-acre dollar amount (commonly referred to as a pooling bonus) determined by the OCC as representing fair market value of the interests relinquished (based on evidence at the hearing).

In this recent round of bankruptcies, it was not uncommon that force pooled respondents found themselves a party to a pooling order held by an operator that filed bankruptcy without having paid the pooling bonus. As a consequence, in many cases those respondents were then left with an unsecured claim in bankruptcy for the pooling bonus, worth considerably less than the bonus the respondents expected to receive when the pooling election was made.

To address that outcome, the Oklahoma legislature enacted Senate Bill 632 (SB 632), 2021 Okla. Sess. Law Serv. ch. 93 (effective Nov. 1, 2021). SB 632 amended the existing 2010 Lien Act so that the lien of that Act is now broadened to cover bonuses due under a pooling order. Further, there are other situations covered by these additional lien rights. Those include unpaid proceeds for a lease bonus due for the acquisition of lease rights and proceeds from an unfulfilled contract or agreement for the purchase of mineral rights. *See* Okla. Stat. tit. 52, § 549.2(9)(b)(4), (5). Those additions appear very straightforward. However, SB 632 also added lien rights with respect to "proceeds owed for oil and gas drilling and development." *Id.* § 549.2(9)(b)(3). It is unclear exactly what this particular addition was intended to cover. It would seem unlikely that it was meant to apply to proceeds due a vendor of materials and services in connection with drilling or development since that situation is generally covered by the mechanic's and materialmen's lien provided by Okla. Stat. tit. 42, § 144. However, additions made to Okla. Stat. tit. 52, § 549.3, which is the operative provision of the 2010 Lien Act under which the lien itself is granted, may provide a clue. To state the purpose of the lien to include the additional coverage provided in section 549.2(9)(b), the words "to secure the obligation of any person to pay any proceeds, as defined in Section 549.2 of this title, for the acquisition of oil and gas rights" were added by SB 632 to section 549.3(A). Further, the provision stating that the lien continues until the sales proceeds are received by the interest owner entitled thereto has been broadened so that proceeds also include "any proceeds, as defined in Section 549.2 of this title, for the acquisition of oil and gas rights." *Id.* § 549.3(C). These additions suggest that proceeds from oil and gas drilling and development were meant to apply to an interest of some sort in oil and gas to be earned by an operator or other person participating in the drilling of a well under an agreement with the interest owner for drilling and development.

Another uncertainty of SB 632 is the effect of the lien termination provisions of section 549.10 of the 2010 Lien Act. Under that provision, the lien granted by the Act to an interest owner expires

> one (1) year after the last day of the month following the date proceeds from the sale of oil or gas subject to such lien are required by law or contract to be paid to such interest owner but only as to the oil or gas sold during such month, unless an action to enforce the oil and gas lien is commenced within such time

or unless there is an intervening bankruptcy. *Id.* § 549.10(A). A bankruptcy results in a stay of the lien. Since the trigger for the one-year period is the due date for payment of production sales proceeds to the entitled interest owner, the triggering event is not an event that applies to the circumstances that were added to lien coverage of the 2010 Lien Act by SB 632. Further, no additional triggering events were added to cover the liens added by SB 632. Query, does that mean that the additional lien coverage added by SB 632 will not be subject to the one-year life of section 549.10, or will a court "find" a trigger event by which the one-year life will be measured?

Constructive Notice and Inquiry Notice May Combine to Give Constructive Notice of Unrecorded Document

Mustang Gas Products, LLC v. Wells Fargo, N.A. (*In re Alta Mesa Resources, Inc.*), No. 19-35133, 2021 WL 2877430 (Bankr. S.D. Tex. July 8, 2021) (mem. op.), involved an adversary proceeding governed by Oklahoma law brought by Mustang Gas Products, LLC (Mustang) in the Alta Mesa Resources, Inc. (Alta Mesa) bankruptcy claiming entitlement to a share of the proceeds of a 11 U.S.C. § 363 sale in bankruptcy by Alta Mesa of substantially all of its assets, including the assets of Alta Mesa's affiliate, Oklahoma Energy Acquisitions, LP (OEA). OEA was a natural gas producer under contract to obtain gathering services from Mustang, including the purchase of OEA's gas, pursuant to various gas purchase agreements (Mustang Agreements). Most of the agreements had previously been acquired by Mustang by a 2005 assignment from ExxonMobil of over 400 gas purchase contracts. Thirty-two of those agreements burdened the OEA wells that were involved in this proceeding. The ExxonMobil assignment was recorded in the land records of Kingfisher County, Oklahoma. None of the Mustang Agreements were recorded in the public land records. However, the ExxonMobil assignment and other recorded agreements referenced the Mustang Agreements.

The central issue in this proceeding was whether the ExxonMobil assignment and other recorded agreements referencing the Mustang Agreements were sufficient put a bona fide purchaser on notice of Mustang's claimed real property interests and the consequences of those interests. Mustang claimed that the covenants formed by the unrecorded Mustang Agreements were covenants running with the land as to OEA's oil and gas assets and that they created real property interests or rights, equal or superior to the rights of OEA's secured lenders, entitling Mustang to share in the proceeds of OEA's § 363 sale.

Wells Fargo Bank, N.A. (Wells Fargo) was the administrative agent for the secured lenders who (apparently) were claiming through Alta Mesa's rights as debtor-in-possession. The court stated those rights gave the debtor-in-possession "the status of 'a bona fide purchaser of real property,' who has a perfected security interest . . . as of the petition date." *In re Alta Mesa*, 2021 WL 2877430, at *4 (quoting 11 U.S.C. § 544(a)(3)). As such, the debtor-in-possession "may avoid a transfer or obligation of the debtor 'that is not perfected and accordingly not enforceable against a bona fide purchaser or lien creditor at the time the bankruptcy petition [was] filed.'" *Id.* (quoting *In re Goodrich Petroleum Corp.*, 554 B.R. 817, 822 (Bankr. S.D. Tex. 2016)). State law determines the status of bona fide purchaser. *Id.* "In Oklahoma, a bona fide purchaser is one who acquires title to an interest in land for valuable consideration, in good faith, and without actual or constructive notice of outstanding rights of others." *Id.* Such a person will take good title. Oklahoma law provides that "[e]very conveyance of real property . . . recorded as prescribed by law from the time it is filed . . . is constructive notice of the contents thereof to subsequent purchasers, mortgagees, encumbrancers or creditors." *Id.* (alteration in original) (quoting Okla. Stat. tit. 16, § 16). Mustang argued that the references in the recorded ExxonMobil assignment gave a subsequent purchaser constructive notice of the content of the Mustang Agreements. *Id.* at *6.

The court held that conclusion expanded Oklahoma constructive notice too far. *Id.* The court held the reference to the Mustang Agreements in the ExxonMobil assignment gave subsequent purchasers constructive notice of the *existence* of the Mustang Agreements. *Id.* However, there was "[n]othing in the land records . . . [that] would provide a bona fide purchaser with actual notice of the *content* of the Mustang Agreements." *Id.* at *4 (emphasis added). The content of the ExxonMobil assignment only included general information about the Mustang Agreements. *Id.* at *6. It did not include details regarding the substance of those agreements. *Id.* The court concluded that although a bona fide purchaser would gain constructive notice of the existence of the Mustang Agreements from the ExxonMobil assignment, a bona purchaser would not gain constructive notice of the content of the Mustang Agreements; that is, such a purchaser would not know the terms of those agreements, including whether they formed real property covenants. *Id.* at *8.

The court reasoned, however, that the ExxonMobil assignment's references to the Mustang Agreements were sufficient to trigger inquiry notice. The court cited Okla. Stat. tit. 25, § 13, which provides: "Every person who has actual notice of circumstances sufficient to put a prudent man upon inquiry as to a particular fact, and who omits to make such inquiry with reasonable diligence, is deemed to have constructive notice of the fact itself." *In re Alta Mesa*, 2021 WL 2877430, at *5. The court relied further upon *Creek Land & Improvement Co. v. Davis*, 115 P. 468 (Okla. 1911), wherein a recorded instrument stating that the property was "subject to contract" gave a purchaser a duty of inquiry notice of an outstanding interest. *In re Alta Mesa*, 2021 WL 2877430, at *5. The court reasoned that because a bona fide purchaser has gained constructive notice of the existence of the Mustang Agreements, that constructive knowledge placed the bona fide purchaser on inquiry notice. *Id.* at *6. The court noted that

> [o]ne who purchases land with knowledge of such facts as would put a prudent man upon inquiry, which, if prosecuted with ordinary diligence, would lead to actual notice of the rights claimed adversely to his vendor, is guilty of bad faith if he neglects to make such inquiry, and is chargeable with the "actual notice" he would have received.

Id. (alteration in original) (quoting *Cooper v. Flesner*, 103 P. 1016, 1020 (Okla. 1909)). The court concluded that such bona fide purchaser "then has the 'duty of ascertaining the terms of the unrecorded contract[s].'" *Id.* (alteration in original) (quoting *Creek Land & Imp. Co.*, 115 P. at 469). The court then stated that Wells Fargo had not shown whether it satisfied its duty of inquiry. *Id.* at *7.

Mustang also argued the open presence of its gathering system on OEA's property also charged a bona fide purchaser with constructive notice. *Id.* The court accepted Mustang's factual contention that it had "visible surface equipment and signage used in the delivery, transportation and processing of gas," with the surface equipment used to move gas from OEA's real property to one of Mustang's five processing plants. *Id.* at *8. The court noted the rule that "[a] purchaser of realty is charged with notice of whatever rights persons in actual possession may possess," *id.* (alteration in original) (quoting *Wade v. Burkhart*, 167 P.2d 357, 358 (Okla. 1946)), and, if the person in possession claims rights inconsistent with record title, "a bona fide purchaser is charged with constructive notice of [that] fact, *triggering a duty to make additional inquiries* regarding title to the property," *id.* (quoting *In re Harrison*, 503 B.R. 835, 843 (Bankr. N.D. Okla. 2013)). The court then reasoned that while "Mustang's physical equipment could put a bona fide purchaser on notice that Mustang possessed portions of the property" and "[a] bona fide purchaser could see that Mustang ha[d] gas gathering equipment and pipelines on the property," knowledge of the gathering system "is not the same as knowledge of the terms of Mustang's gas gathering agreements." *Id.* However, it concluded that "a reasonably diligent purchaser would attempt to learn the terms of those agreements." *Id.* Again, the court emphasized that the record does not indicate whether Wells Fargo diligently inquired about the Mustang Agreements. *Id.*

Note that over 90 years ago a federal appellate court applying Oklahoma law also found that visible surface equipment related to a pipeline easement triggered inquiry notice to a purchaser. *Sw. Pipe Line Co. v. Empire Nat. Gas Co.*, 33 F.2d 248, 254 (8th Cir. 1929).

PENNSYLVANIA – MINING

Joseph K. Reinhart, Sean M. McGovern, Gina N. Falaschi & Christina Puhnaty
– Reporters –

PADEP Issues Draft Technical Guidance Regarding Synthetic Liners and Caps at Coal Refuse Disposal Areas

On August 21, 2021, the Pennsylvania Department of Environmental Protection (PADEP) issued a draft revision of its technical guidance that explains PADEP's considerations when evaluating liners and cap systems installed at coal refuse disposal areas pursuant to 25 Pa. Code chs. 86, 88, and 90. *See* PADEP, Draft TGD No. 563-2112-656, "Liners and Caps for Coal Refuse Disposal Areas" (Aug. 21, 2021) (Draft TGD). These systems of liners and protective caps, called "barrier layers," are intended to prevent adverse impacts to groundwater and surface water and to prevent precipitation from coming into contact with coal refuse by preventing or reducing water migration through the refuse material. *See* 25 Pa. Code §§ 90.50(a)–(b), .101–.102, .122. As noted in the preamble for the rulemaking that established section 90.50(b), "[t]his statutory requirement was intended to ensure that precipitation contacting the coal refuse is kept to a minimum, thereby reducing the volume of water needing treatment after the site is closed." 31 Pa. Bull. 3735, 3736 (July 14, 2001). PADEP noted that this draft technical guidance document, when finalized, would not mandate that existing structures be replaced or retrofitted.

PADEP's current guidance serves as a guide for the use of liners for impoundments, stockpiles, and coal refuse disposal areas. *See* PADEP, TGD No. 563-2112-656, "Liners and Caps for Coal Refuse Disposal Areas" (July 17, 2021). PADEP's draft revision of this technical guidance is significantly different from the current guidance in that the revised draft guidance incorporates protective caps and emphasizes PADEP's preference for barrier layers constructed using synthetic material rather than clay. The draft guidance explains PADEP's characterization of the differences between these two types of low permeability/impermeable barrier layers: "low hydraulic conductivity" soils (i.e., clay) and synthetics. Synthetics include flexible polymeric sheets or flexible membrane liners. PADEP considered the appropriateness of these materials for both liners and caps at coal refuse disposal areas. According to PADEP, clay may be used if the material is of a specific quality and consistency, and PADEP considers the use of clay liners appropriate where the liner system will not be subject to continual hydraulic head conditions. The agency listed coarse refuse facilities, temporary storage areas, and outslopes of refuse facilities as such locations. Draft TGD at 1–2.

Similarly, PADEP concluded that "clay caps are generally unsuitable for circumstances with high hydraulic head conditions, for slurry impoundments, or as a permanent cap for any coal refuse," and encourages synthetic liners in these situations. *Id.* at 2. PADEP lists "erosion prevention, cracking and deterioration from exposure, anticipated activity or construction on the final capped area, settlement, and shifting" as considerations when choosing caps, and notes that "clay soils are susceptible to drying out over time," which can result in vegetation root systems penetrating the caps. *Id.* at 7.

The draft guidance further explains that PADEP considers synthetics to be "the best and most practical choice to prevent precipitation from coming into contact with the coal refuse to the maximum extent practicable" due to synthetic material's durability and longevity. *Id.* at 3. As noted above, the relevant regulatory provisions were "intended to ensure that precipitation contacting the coal refuse is kept to a minimum." *Id.* at 6. The draft guidance recommends synthetic barrier layers under high head slurry impoundment coal refuse disposal areas where water has the potential to be held against the liner system for an extended duration (high head conditions). *Id.* at 3. PADEP notes in the draft guidance that it will consider other technologies that meet or exceed the requirements of the guidance. *Id.*

The draft guidance then sets forth standards for both liners and caps that can further aid facilities in determining the type of barrier layer appropriate for a coal refuse disposal area. *Id.* at 4–9. The draft guidance also explains what information applicants should submit to PADEP when proposing to install barrier layers at their facility. *Id.* at 9–10. Finally, the draft guidance explains what information regarding its barrier layers applicants should submit to PADEP during PADEP-approved periods of temporary cessation exceeding 90 days. *Id.* at 11. Several statutory provisions require site operators to seek PADEP approval when temporarily halting operation of a coal refuse disposal area for a period longer than 90 days. *See* 25 Pa. Code §§ 88.310(k)(1), 90.122, .167. The draft guidance provides that, during these periods, operators must demonstrate to PADEP that the site has the appropriate controls in place to minimize the extent of precipitation reaching the coal refuse disposal area. Draft TGD at 11.

Pursuant to the Coal Refuse Disposal Action Plan approved by the U.S. Office of Surface Mining Reclamation and Enforcement (OSMRE) on August 19, 2019, PADEP was projected to complete its revision of this guidance document by December 31, 2020. *See* Coal Refuse Disposal Action Plan, Action Plan ID: PA-EY2020-002 (Aug. 19, 2019) (on file with author). This deadline has since been extended by OSMRE to June 30, 2022. *See* Letter from Ben Owens, OSMRE, to William S. Allen, Jr., PADEP Bureau of Mining Programs (Dec. 14, 2020) (on file with author). These documents are also available at https://www.odocs.osmre.gov/.

EQB Publishes Proposed Changes to RACT Requirements for Major Sources of NO_x and VOCs

On August 7, 2021, the Environmental Quality Board (EQB) published a proposed rule to amend 25 Pa. Code chs. 121 and 129 to address 2015 8-hour National Ambient Air Quality Standards (NAAQS), which is commonly known as the RACT III rule. *See* Additional RACT Requirements for Major Sources of NO_x and VOCs for the 2015 Ozone NAAQS, 51 Pa. Bull. 4333 (proposed Aug. 7, 2021). The Pennsylvania Department of Environmental Protection (PADEP) developed the rule in response to the U.S. Environmental Protection Agency's (EPA) October 26, 2015, revision to the primary and secondary NAAQS for ozone. *See* NAAQS for Ozone, 80 Fed. Reg. 65,292 (Oct. 26, 2015) (to be codified at 40 C.F.R. pts. 50–58). Under section 110 of the Clean Air Act, 42 U.S.C. § 7410, states are required to reevaluate reasonably available control technology (RACT) requirements each time the ozone NAAQS are promulgated for nonattainment areas. Because Pennsylvania is in the Ozone Transport Region, RACT is applicable to nitrogen oxides (NO_x) or volatile organic compounds (VOCs) across the commonwealth.

The proposed rulemaking would add the terms "combustion source" and "natural gas compression and transmission facility fugitive VOC air contamination source" to the definitions in 25 Pa. Code § 121.1. The addition of these terms supports proposed chapter 129 amendments adopting presumptive RACT requirements and emission limitations for certain major stationary sources of NO_x and VOCs in existence on or before August 3, 2018.

Comments on the proposed rule were due on October 12, 2021, and the Pennsylvania Independent Regulatory Review Commission was required to provide comments by November 12, 2021. PADEP intends to finalize the rule in the first quarter of 2022 with compliance anticipated to begin on January 1, 2023. EPA will review the proposed rulemaking for approval as a revision to Pennsylvania's state implementation plan following promulgation of final-form rulemaking.

PADEP's RGGI Rule Nears the End of the Rulemaking Process

As reported in previous editions of this *Newsletter*, the CO_2 Budget Trading Program rulemaking is a proposal by the Pennsylvania Department of Environmental Protection (PADEP), pursuant to Governor Tom Wolf's 2019 executive order, to join the Regional Greenhouse Gas Initiative (RGGI). RGGI is a regional cap-and-trade program for carbon dioxide (CO_2) emissions from fossil fuel-fired electric generating units with a nameplate capacity of 25 megawatts or greater. *See* Vol. XXXVIII, No. 3 (2021), Vol. XXXVIII, No. 2 (2021), Vol. XXXVIII, No. 1 (2021), Vol. XXXVII, No. 4 (2020), Vol. XXXVII, No. 3 (2020), Vol. XXXVII, No. 2 (2020), Vol. XXXVII, No. 1 (2020), Vol. XXXVI, No. 4 (2019) of this *Newsletter*. At its July 13, 2021, meeting, the Environmental Quality Board debated and voted 15-4 to adopt the final CO_2 Budget Trading Program regulation. On September 1, 2021, the Independent Regulatory Review Commission (IRRC) approved the regulation by a vote of 3 to 2.

Following IRRC approval, the final-form rulemaking was sent to the Pennsylvania House and Senate Environmental Resources and Energy standing committees. On September 2, 2021, the Pennsylvania House Environmental Resources and Energy Committee passed a resolution disapproving the regulation. On September 14, 2021, Pennsylvania's Senate Environmental Resources and Energy Committee also passed a resolution disapproving the regulation. The full Senate voted in favor of the resolution on October 27, 2021, and, if the resolution also passes in the House, it will be presented to Governor Wolf.

The Governor is expected to veto any disapproval measure, which then would require a veto-proof majority from the legislature to override the veto and block the regulation. If the legislature is unsuccessful in blocking the regulation, it will be submitted to the Office of the Attorney General for review, and if approved, published in the *Pennsylvania Bulletin* as a final rule.

The Governor intends to finalize the regulation by the end of 2021 and regulated entities could be required to begin compliance on January 1, 2022. Legal challenges to the rule are anticipated. Further information regarding the rule can be found on PADEP's RGGI webpage at https://www.dep.pa.gov/Citizens/climate/Pages/RGGI.aspx.

Wolf Administration Releases Statewide Climate Change Action Plan

On September 22, 2021, Governor Tom Wolf released the Pennsylvania Climate Action Plan 2021. In accordance with the Pennsylvania Climate Change Act of 2008 (Act 70 of 2008), 71 Pa. Stat. §§ 1361.1–.8, the plan must be updated every three years. The Pennsylvania Department of Environmental Protection (PADEP) and the Climate Change Advisory Committee developed and presented the 2021 plan to the Governor. It outlines a plan to reach the goal that the Governor set in 2019 to reduce greenhouse gas (GHG) by 26% by 2025 and by 80% by 2050 from 2005 levels. It also identifies GHG inventory, forecast, and reduction efforts, GHG emission reduction strategies, GHG reduction modeling results, and adaption opportunities, and recommends legislative changes to achieve identified goals.

PADEP and the Climate Change Advisory Committee also produced an overview of the plan. *See* Climate Action Plan 2021 Overview (Sept. 2021). This overview compiles the strategies that government, industry, business, and community organizations can immediately implement to reduce GHG emissions suggested in the plan. Some of the proposed strategies, which focus on both existing programs and emerging technologies, include:

- joining the Regional Greenhouse Gas Initiative and Transportation Climate Initiative Program to cap carbon emissions from the transportation and electric generation sectors;
- adopting codes for new buildings that go above and beyond standard codes, increasing training for inspectors on existing building codes, and establishing a commercial building energy performance program to accelerate energy efficiency;
- expanding the provisions of Act 129 of 2008 to increase the annual energy savings targets for electric distribution companies and developing a similar program for gas utilities;
- increasing the Alternative Energy Portfolio Standards to require electricity generators to get more of their energy from clean renewable sources;
- amending the Pennsylvania Clean Vehicles Program to increase the availability of light-duty electric vehicles through a rulemaking that would establish a requirement for automakers to include light-duty electric vehicles as a percentage of their model offerings;
- re-funding the Pennsylvania Sunshine Solar Rebate Program for homeowners and small businesses;
- incentivizing battery storage at the grid level;
- assessing the potential role of alternatives to natural gas;
- pursuing carbon capture, use, and storage technologies for emissions from fossil fuel combustion source points;
- using direct air capture systems to remove existing atmospheric carbon dioxide;
- implementing strategies to increase peak load management and keep the grid in balance as more renewable electricity comes online; and
- ensuring that climate action statewide is informed by the work of the PADEP Environmental Justice Office.

A copy of the plan and additional information is available on PADEP's Pennsylvania Climate Action Plan website at https://www.dep.pa.gov/Citizens/climate/Pages/PA-Climate-Action-Plan.aspx.

PENNSYLVANIA – OIL & GAS

Joseph K. Reinhart, Sean M. McGovern & Matthew C. Wood
– Reporters –

PADEP Issues Guidelines for Implementing Area of Review Regulatory Requirement for Unconventional Wells

On September 4, 2021, the Pennsylvania Department of Environmental Protection (PADEP) published notice of its final technical guidance titled "Guidelines for Implementing Area of Review (AOR) Regulatory Requirement for Unconventional Wells," No. 800-0810-001 (Sept. 4, 2021) (AOR Guidance). *See* 51 Pa. Bull. 5757 (Sept. 4, 2021). The AOR Guidance clarifies the AOR as "1,000 feet in all directions" from the plan view projections for horizontal and vertical unconventional wells. *See* 25 Pa. Code § 78a.52a(a). Vertical buffer distance for offset wells located within the AOR is 1,500 feet for all unconventional wells. *See* 25 Pa. Code § 78a.73(c). The final guidance document was effective upon date of publication, replacing PADEP's 2016 guidance. Operators should reference the AOR Guidance regarding well placement and offset wells, for evaluating and monitoring nearby wells to prevent communication between wells, and for reporting and resolving incidents. The AOR Guidance also serves as an overview of PADEP's well adoption permitting process.

Final issuance of the AOR Guidance followed a 60-day public comment period during which PADEP received approximately 55 comments from 10 commenters and made several changes to the draft version. Key changes to the AOR Guidance, as identified in the *Pennsylvania Bulletin*, include:

- clarifying the ability of operators to survey an area that extends beyond the prescriptive AOR regulatory language;
- removing language assigning responsibility for recently plugged offset wells to the operator who had completed the plugging;
- relocating language pertaining to briefing the hydraulic fracturing operations team about adjacent operator coordination;
- updating incident reporting language; and
- modifying operator coordination with PADEP field inspection staff ahead of hydraulic fracturing.

The AOR Guidance and related materials are available in PADEP's eLibrary, "Oil and Gas (550-) (800-)" folder. *See* http://www.depgreenport.state.pa.us/elibrary/GetFolder?FolderID=4613.

Office of Environmental Justice Includes Oil and Gas Public Engagement Section in Revised Environmental Justice Public Participation Policy and Governor Wolf Issues Executive Order Regarding Environmental Justice

On August 19, 2021, the Pennsylvania Department of Environmental Protection (PADEP), Office of Environmental Justice (OEJ), released a working draft of the Environmental Justice Public Participation Policy (EJ Policy Working Draft) to the Environmental Justice Advisory Board (EJAB). *See* Environmental Justice Policy, No. 012-0501-002 (Aug. 19, 2021). Unlike

PADEP's 2004 EJ Policy, currently in effect, the EJ Policy Working Draft considers oil and gas drilling and operating permits as trigger permits. *Id.* § II(A)(1) & app. A. Trigger permits are identified as permits for regulated activities that traditionally lead to significant public concern due to potential environmental, human health, and community impacts. *Id.* § II(A)(1).

Section IV of the EJ Policy Working Draft includes provisions for public engagement specific to unconventional oil and gas drilling and operations. These provisions are limited only to unconventional oil and gas drilling operations due to the 45-day permit review period specified by the Pennsylvania legislature pursuant to Act 13 of 2012. *See* 58 Pa. Cons. Stat. § 3211(e). The EJ Policy Working Draft states that the PADEP oil and gas program in collaboration with OEJ should conduct an annual assessment of operators with anticipated or actual drilling operations in EJ areas, as defined within the policy. EJ Policy Working Draft § IV(A)(1). Operators must create a summary of their projects identified in the annual assessment and submit the summary to PADEP for review. *Id.* § IV(A)(2). Additionally, operators are encouraged to attend community meetings to discuss planned activities as identified in the annual assessment. *Id.* § IV(B)(1).

Inclusion of oil and gas drilling and operating permits as trigger permits in the EJ Policy Working Draft could affect the oil and gas industry. First, the EJ Policy Working Draft would require unconventional drilling and operating permit applicants in EJ areas to undergo EJ analysis and enhanced public participation and engagement. *Id.* § II(B). Second, unconventional operators will need to report active and anticipated drilling operations at existing unconventional well pads on an annual basis. *Id.* § IV(A)(1). In other words, the EJ Policy Working Draft would apply to already permitted and active drilling operations that continue following the policy's scheduled summer 2022 implementation date. While the intent of section IV is to align EJ analysis with the statutory limitations of the 45-day unconventional well permit review time frame in Act 13 of 2012, the inclusion of oil and gas drilling and operating permits in the EJ Policy Working Draft would create additional public participation requirements for the industry.

On October 28, 2021, Governor Tom Wolf issued Executive Order 2021-7 (EO 2021-7), permanently establishing both OEJ and EJAB, and creating the Environmental Justice Interagency Council (EJIC). The EJIC would, among other responsibilities, be charged to "[i]dentify and make recommendations to the Governor's Office to address potential disproportionate environmental impacts that state laws, regulations, policies, and activities may have on Pennsylvania residents in Environmental Justice Areas." *Id.* § 4(c). The executive order also cites federal EJ initiatives and Executive Order No. 14,008, "Tackling the Climate Crisis at Home and Abroad," 86 Fed. Reg. 7619 (Jan. 27, 2021), issued by the Biden administration earlier this year, and directs OEJ to develop and publish an EJ strategic plan every five years. EO 2021-7, § 2(b)(5).

In concert with the executive order, two proposals were introduced to the Pennsylvania legislature. On October 26, 2021, Representative Donna Bullock (D-Phila.) proposed House Resolution 151, recognizing the thirtieth anniversary of the adoption of the 17 principles of EJ that were presented to delegates at the First National People of Color Environmental Leadership Summit. Senator Vincent J. Hughes (D-Phila.) proposed Senate Bill 189, which closely resembles EO 2021-7 and amends the Administrative Code of 1929 (P.L. 177, No. 175) to establish an EJ task force and regional EJ committees.

As directed by EO 2021-7, PADEP is expected to further revise its EJ Policy Working Draft, which was scheduled to be discussed at the November 16, 2021, EJAB meeting. Both legislative proposals have been respectively referred to the House and Senate Environmental Resources and Energy Committees. If the Senate bill makes it through the legislature, it will go into effect 60 days after passage.

PADEP Expresses Willingness for Program Allowing Road Application of Conventional Drilling Wastewater If Data Supports

The Pennsylvania Grade Crude Development Advisory Council (CDAC) is mandated to examine and make recommendations about existing technical regulations and policies implemented by the Pennsylvania Department of Environmental Protection (PADEP). At CDAC's most recent meeting on August 19, 2021, PADEP representatives discussed potentially developing new regulations to allow the spreading of conventional oil and gas produced water (COGPW) as dust suppressant on unpaved roadways. This practice had been authorized for decades by PADEP and was largely used by local municipalities in northwest Pennsylvania via a PADEP approval process. *See* Fact Sheet, PADEP, "Roadspreading of Brine for Dust Control and Road Stabilization" (July 2011). PADEP previously attempted to amend 25 Pa. Code ch. 78 to include provisions governing road spreading of COGPW, but those revisions were never finalized. In 2018, in response to the Environmental Hearing Board's (EHB) decision in *Lawson v. PADEP*, No. 2017-051-B (EHB May 17, 2018), PADEP implemented a moratorium on such road spreading. At the August meeting, attendees discussed reports of a Pennsylvania State University study in which researchers evaluated the efficacy of COGPW against commercially available alternatives. Among other things, the study found that dust suppression efficacy of all formulations of tested COGPW was less than the commercial alternatives. *See* Audrey M. Stallworth et al., "Efficacy of Oil and Gas Produced Water as a Dust Suppressant," 799 *Sci. of the Total Env't* 149347 (2021).

Kurt Klapkowski, Director of PADEP's Bureau of Oil and Gas Management, explained during the meeting that past regulatory attempts to allow the spreading of COGPW as a dust suppressant and for other uses had been challenged in court (e.g., *Lawson*) and as such, any new regulations would have to be defensible and supported by applicable data. *See* Audio Recording of August 19, 2021, CDAC Meeting, https://drive.google.com/file/d/1OJT9q9FlIVmjM1skJKpwWZKzBSQkQpic/view. Klapkowski said that PADEP had funded and worked with Penn State to produce another study in an attempt to develop such data to support a program of road spreading that PADEP would approve under applicable regulations and would be defensible before the EHB, the courts, and under applicable statutes. *Id.* That study is forthcoming.

Since the August meeting, parties on both sides of the issue have reached out to PADEP. In a September 10, 2021, letter to PADEP Secretary Patrick McDonnell, CDAC chair Dave Hill stated, among other things, that PADEP had prevented CDAC from carrying out its statutory duties to evaluate and make recommendations by failing to inform CDAC of the two Penn State studies, which Hill said were clearly within CDAC's purview. The letter was published in *PIOGA Press* Issue 138, at 10 (Oct. 2021). Hill argued that at least one of the studies could have benefited from CDAC's expertise. On October 8, 2021, in response to Klapkowski's comments at the August CDAC meeting, an environmental group submitted a letter signed by 80 organizations and businesses and approximately 1,800 individuals requesting, among other things, that PADEP halt any plans to develop regulations that would allow road spreading COGPW. *See* Letter to PADEP (Oct. 8, 2021), https://drive.google.com/file/d/1dEziy2H4PCOQS-LcKeqrRuZxxVUE-OND/view. At the time of this report, PADEP had not proposed regulations governing the use of COGPW for road application.

Environmental Groups Submit Rulemaking Petitions to EQB for Full-Cost Bonding for Oil and Gas Well Plugging

On September 14, 2021, several environmental groups, including the Sierra Club and PennFuture, submitted two rulemaking petitions to the Pennsylvania Department of Environmental Protection (PADEP) requesting that the Environmental Quality Board (EQB) require full-cost bonding for conventional and unconventional wells. The environmental groups contend that the full-cost bonds are necessary to incentivize operators to plug non-producing wells (or ensure that the commonwealth has funds available to do so).

For conventional wells, the petitioners seek to amend 25 Pa. Code § 78.302 in four ways: (1) increase the per-well bond amount from $2,500 to $38,000 (which the petitioners note is in line with PADEP's estimated average cost to plug an abandoned well); (2) for blanket bonds, which can cover multiple wells, increase the amount from $25,000 to the sum of the individual bond amounts for the number of wells (e.g., five wells at $38,000 results in a $190,000 bond); (3) apply the revised bond amounts to all new wells and wells that were in existence as of April 17, 1985; and (4) require PADEP to issue a report to EQB every two years that recommends whether EQB should further adjust bond amounts (or every four years, if two years is not feasible). *See generally* Conventional Well Bonding Petition (Sept. 14, 2021).

The petitioners are also seeking a new regulation in 25 Pa. Code ch. 78 to govern bonding for unconventional wells, with even larger increases in bond amounts. That is, the petitioners are requesting an increase from the $4,000 starting cost to $83,000 per unconventional well. Likewise, the petitioners are proposing the same approach for blanket bonds (i.e., $83,000 multiplied by the number of wells). The proposed effective date and PADEP-required report are identical to the petition for conventional wells. *See generally* Unconventional Well Bonding Petition (Sept. 14, 2021). Of note, bonding for unconventional wells is already governed by 25 Pa. Code § 78a.302, which contradicts the petitioners' proposed new regulation.

Regarding next steps for the rulemaking petitions, PADEP will use EQB's Petition Policy (25 Pa. Code ch. 23) to determine whether the petitions are complete and whether EQB can take the proposed actions without conflicting with federal law. In the event PADEP determines that one or both of the petitions meet these conditions, it will inform EQB. The petitioners will then have an opportunity to make oral presentations at the next EQB meeting (occurring at least 15 days after PADEP's determination) and PADEP will recommend to EQB whether it should accept the petitions.

TEXAS – OIL & GAS

William B. Burford
– Reporter –

Deed Conveying Tract, Without Reservation, and "Likewise" One-Eighth of the Minerals Held to Have Reserved Seven-Eighths of Minerals to Grantors

The court in *Barrow Shaver Resources Co. v. NETX Acquisitions, LLC*, No. 06-20-00081-CV, 2021 WL 3571394 (Tex. App.—Texarkana Aug. 13, 2021, pet. filed) (mem. op.), construed a 1963 deed from Jamie T. Dawson and James E. Hill, owners of all of the surface and mineral estates of a 181-acre tract of land in Cass County, Texas, to John L. and Treba Juanita Stone. The deed's granting clause conveyed the land, described by metes and bounds, without mention of any exceptions or reservations other than that it was subject to any easements and reservations of record. That wording was followed by the sentence, "[t]here is likewise conveyed to Grantees by this conveyance one-eighth (1/8) of all Oil, Gas, and Other Minerals." *Id.* at *1.

Reversing the trial court's summary judgment for the successors to the interest of the Stones, the grantees, the court of appeals held that the deed had unambiguously been intended to convey only an undivided one-eighth interest in the minerals and to have reserved seven-eighths to the grantors. The court acknowledged the rule that any reservation must be by clear language and cannot be implied, but emphasized, relying heavily on *Piranha Partners v. Neuhoff*, 596 S.W.3d 740 (Tex. 2020), *see* Vol. XXXVII, No. 2 (2020) of this *Newsletter*, that it must "consider the entire agreement and, to the extent possible, resolve any conflicts by harmonizing the agreement's provisions, rather than by applying arbitrary or mechanical default rules." *Barrow Shaver*, 2021 WL 3571394, at *4 (quoting *Piranha*, 596 S.W.3d at 744). By the deed's expressly stating that the grantors were "likewise" conveying a one-eighth mineral interest, the court explained, they indicated their intent to convey in the granting clause something less than the fee simple estate. *Id.* at *5. "Construing the initial property description together with the 'likewise' conveyance provision in the only way that [could] give effect to both grants," the court concluded, the deed conveyed (1) the entire surface estate of the tract and (2) one-eighth of the mineral estate. *Id.*

Oil and Gas Lease's Retained-Acreage Clause Construed

The decision in *Vermillion FC, LP v. 1776 Energy Partners, LLC*, No. 04-20-00089-CV, 2021 WL 3743514 (Tex. App.—San Antonio Aug. 25, 2021, no pet. h.) (mem. op.), concerned and oil and gas lease from Vermillion FC, LP (Vermillion) to 1776 Energy Partners, LLC (1776 Energy) on a tract of approximately 1,100 acres in Zavala County, Texas. The lease had a primary term that extended until July 20, 2013, with a provision that the primary term could be extended two years by the lessee's payment of $2,300 per acre not then included in a "well tract," that the lease would remain in effect after the primary term only as to acreage designated as part of a "well tract," and that the lessee must thereupon release the rest of the acreage. 1776 Energy drilled one well early in the lease term and, shortly before the end of the primary term, provided Vermillion notice that it had designated a 320-acre "well tract" for the well. It eventually released the excess acreage, but not until more than two years after the lease required it to do so. The lawsuit resulted from the parties' disagreement over the amount of acreage 1776 Energy was entitled to retain as a "well tract" and the consequences of its failure to release the expired acreage.

The principal dispute was over the amount of acreage the lease allowed the lessee to retain as a "well tract" for its producing horizontal oil well, 1776 Energy contending that its 320-acre designation was proper and Vermillion arguing that the lease allowed 1776 Energy only 40 acres. Section 6 of the lease defined a "well tract" as the minimum number of acres sufficient under applicable state agency field rules for creation of an allowable sufficient to cover actual production, limited to 40 acres if those would "permit a fort[y] (40) acres spacing." *Id.* at *5 (alteration in original). Section 6 continued with the following in all capital letters:

> Notwithstanding the above, in the event any governmental authority having jurisdiction should hereafter establish a density or spacing pattern of a different number of acres around oil and/or gas wells for full allowable purposes than the number of acres specified above, then lessee may only retain around each oil well and each gas well such number of acres as necessary to allow maximum production.

Id.

After 1776 Energy's well was completed, the Texas Railroad Commission enacted field rules for the area that were in effect at the end of the lease's primary term. Those rules established the size of a standard drilling and proration unit as 80 acres and provided that additional acreage may be assigned to a horizontal well in accordance with Statewide Rule 86, which includes a table of additional acreage that may be assigned depending on a well's horizontal displacement. The field rules further provided that an operator, at its option, would be permitted to form optional drilling units of 40 acres, subject to proportionate allowable credit for a well on a fractional proration unit. *Id.* at *6.

Because of Section 6's "notwithstanding" wording, plainly stating that field rules control to the extent they provide for additional acreage, the court held, 1776 Energy was not limited to the minimum acreage that the earlier part of Section 6 would have allowed it. Without much explanation, it rejected Vermillion's argument that the lease allowed more acreage to be retained according to field rules only if necessary to accommodate the well's actual production. Based on the well's horizontal displacement, according to the court, 1776 Energy was entitled to assign 200 acres to its well's drilling and proration unit, for a total of 280 acres (not 320 acres, as 1776 Energy contended, apparently having misinterpreted the field rules' allowance of tolerance acreage under circumstances that were not present here). *Id.* at *6–7.

Vermillion also argued that because 1776 Energy had not given it a timely release of the acreage as to which the lease expired, as the lease required, the lessee had become obligated to pay the additional bonus for extension of the lease's primary term. The court disagreed, pointing out that nothing in the lease's provision granting the lessee the right to extend the primary term by delivering payment to the lessor suggested that its declining to do so required any affirmative action. The failure to pay simply resulted in the lease's termination except as to acreage outside the well tract. *Id.* at *10.

Email Correspondence Held Not to Have Constituted Contract for Sale of Overriding Royalty

The Gary and Theresa Poenisch Family Limited Partnership (Poenisch) and TMH Land Services, Inc. (TMH), among others, owned portions of an overriding royalty interest in a mineral lease called the Wiatrek lease. All of the overriding royalty owners agreed with GulfTex Energy IV, LP (GulfTex), evidently the owner of the working interest under the lease, to reduce their interests. During the course of the negotiations that led up to that agreement, Poenisch had said it would agree to the reduction if it could acquire one of the other owners' interests. In an email to the spokesperson for the overriding royalty owners and to their attorney, TMH's president stated, "I will sell my retained [overriding royalty interest] in the GulfTex proposed 300+ acre unit for $20,000," to which Poenisch's counsel replied, "We have a deal." *Gary & Theresa Poenisch Family Ltd. P'ship v. TMH Land Servs., Inc.*, No. 04-20-00300-CV, 2021 WL 4173309, at *1 (Tex. App.—San Antonio Sept. 15, 2021, no pet. h.) (mem. op.) (footnote omitted). The GulfTex agreement reducing the overriding royalty was executed without any sale from TMH to Poenisch having occurred. About a year after the TMH-Poenisch email correspondence, after GulfTex had begun to produce from the lease, Poenisch requested that TMH close the sale of its overriding royalty interest to Poenisch for $20,000. TMH refused, and Poenisch filed suit to enforce its alleged contract with TMH. The trial court granted summary judgment to TMH, and in *Poenisch* the court of appeals affirmed.

The court of appeals agreed with TMH and with the trial court that the correspondence could not have resulted in an enforceable contract because it failed to satisfy the statute of frauds, lacking a sufficient description of the interest to be conveyed. Poenisch argued that the land and interest could be determined by reference to extrinsic evidence, but the court pointed out that extrinsic evidence may be used for the purpose of identifying the property to be conveyed only if the writing relied upon contains the means or data by which the property can be identified or a "key or nucleus" description of the property. *Id.* at *3. The TMH email did not meet those criteria: "[A] person familiar with the locality would not be able to determine what percentage of the overriding royalty interest [was to be] conveyed; the general area of the property . . . ; or the size, shape, or boundary of the property covered by the mineral lease." *Id.* Further, although the TMH email had been sent after preceding GulfTex submittals that did sufficiently describe the property, the TMH email did not clearly refer to those, and the reference to a "300+ acre unit" did not correspond to the 177.98-acre GulfTex agreement. *Id.* at *4.

Lease Held Partially Terminated Under "Separate Lease" Wording as to Non-Contiguous Tract Without Production or Operations

The court in *Tier 1 Resources Partners v. Delaware Basin Resources LLC*, No. 08-20-00060-CV, 2021 WL 4260793 (Tex. App.—El Paso Sept. 20, 2021, no pet. h.), construed oil and gas leases from the Bush family to Delaware Basin Resources LLC (DBR), each of which were identical in form and covered two sections of land, Section 2, Block C-3, and Section 6, Block C-5, PSL Survey, Reeves County, Texas. The two sections were not contiguous, separated from each other by approximately a mile. The leases were in a typical form under which they would remain in effect for a primary term of three years from their dates in February 2014 and as long thereafter as oil or gas was produced. Each also contained an addendum as Exhibit A, which included a Paragraph 13, for partial termination either at the end of the primary term or, if continuous development were then in progress, at such time as development ceased, and a Paragraph 11, which read as follows:

> Notwithstanding any other provisions of this Lease or any wording contained herein . . . each of the separately designated tracts described shall be treated for all purposes as a separate and distinct Lease. All of the

> provisions contained in this Lease form shall be applicable to each such tract and be construed as if a separate Lease agreement had been made and executed covering each such tract.

Id. at *2.

During the primary term of the leases DBR drilled several wells on Section 6 but none on Section 2. After the primary term expired in early 2017, the Bush lessors executed new leases to Tier 1 Resources Partners (Tier 1). A lawsuit ensued, DBR maintaining that continuous development of Section 6 had perpetuated the leases as to both sections and the Bushes and their new lessee Tier 1 countering that the leases had expired as to Section 2. The trial court granted summary judgment to DBR, but the court of appeals reversed.

The dispute, the court succinctly observed, centered on whether the leases' Paragraph 11 wording created two separate leases, one covering Section 6 and one covering Section 2. *Id.* at *6. Agreeing with the Bushes and Tier 1, the court concluded that it unambiguously did so. The court rested its interpretation principally on the ordinary, generally accepted meaning of the word "tract": an individual parcel that does not share a common border with another parcel under common ownership. *Id.* at *7. The question, given that interpretation, was whether anything in the lease could reasonably be interpreted as describing multiple tracts. The only place the leases did that was in their land description, and, the court held, the only reasonable interpretation of that description and Paragraph 11 was that there were two "separately designated" tracts. *Id.* That being the case, since there was no production and there had been no operations on the separate lease covering Section 2, as created by Paragraph 11, the leases had expired as to Section 2. *Id.*

DBR pointed to other leases in the area by the same lessors containing identical Paragraph 11 wording but with land descriptions that clearly identified separate "tracts." Those, DBR argued, showed that the Bushes knew how to designate separate tracts but had chosen not to do so in the DBR lease. The court was unpersuaded. Those other leases were the result of unknown negotiations with different lessees and could not provide insight as to the parties' intent here, it said, and the court would not consider such extrinsic evidence to create an ambiguity where none existed. *Id.* at *8.

Surface Cotenant of Mineral Classified Land Held Entitled to Challenge Occupying Cotenant's Use

Rancho Viejo Cattle Co. v. ANB Cattle Co., No. 04-20-00143-CV, 2021 WL 4443709 (Tex. App.—San Antonio Sept. 29, 2021, no pet. h.), concerned land subject to Texas's peculiar Relinquishment Act. That legislation affects land sold by the state of Texas between 1896 and 1919 with a "mineral" classification that resulted in reservation of the oil, gas, and other minerals underlying the land to the state. Notwithstanding the state's ownership of the entire mineral estate in "mineral classified" land, under the Relinquishment Act the "owner of the soil," i.e., the surface owner, is constituted the state's agent for the purpose of leasing the oil and gas and is entitled to one-half of any leasing bonuses, delay rentals, and royalties on production.

The two surveys at issue in this case were mineral classified tracts that were part of approximately 22,000 acres in Webb County, Texas, known as the Yugo Ranch, which had been owed by C.Y. Benavides. The surface estate of the ranch eventually became divided between his two sons, Carlos and Arturo. At the time of the lawsuit the surface of the southern half was generally held by Rancho Viejo Cattle Co., Ltd. (RVCC), owned by Carlos's family, and the northern half by ANB Cattle Co., Ltd. (ANB), owned by Arturo's family. However, although the surface ownership had been divided between the two families, mineral ownership had instead generally been kept undivided and owned by the members of both families. Because the benefits of acting as the state's agent in leasing the state's oil and gas underlying mineral classified land by law cannot be severed from the surface ownership, the two families had in 1990 cross-conveyed the surface ownership in the tracts of their land that were mineral classified, so that each family would own an undivided one-half, and in 1998 they entered into a stipulation that specified certain rights and duties concerning the use of the surface. *Id.* at *1–2. Among other things, the 1990 cross-conveyance provided that the previous owner (RVCC in the case of the disputed land) "shall remain in exclusive possession of said lands and shall have the exclusive right to continue to occupy all portions of any such surveys . . . for hunting and grazing purposes in consideration of that partnership paying the ad valorem taxes due on such acreage . . . ." *Id.* at *7 (alteration omitted). The 1998 stipulation vested in the owner of the surrounding ranch "the exclusive right (executive rights) to negotiate and conclude all terms in connection with [the surface use for mineral operations], keeping the interest of the non-executive limited partnership in mind." *Id.* at *11. It then specified that the standard of conduct of the "executive" owner would be "that of which a fiduciary owes to his beneficiary or principal . . . ." *Id.*

In 2011 RVVC conveyed its interest in all or part of the disputed tracts to another family-owned entity, Rancho Viejo Waste Management, LLC (RVWM), which then sought a permit to construct a municipal solid waste landfill and recycling center on the land. After the state and ANB complained that the proposed landfill would prevent mineral development, RVWM removed the disputed tracts from the proposed landfill but still proposed to build a berm across the land to divert floodwater away from the landfill and install groundwater monitoring wells on the land. The state declined to object to RVWM's amended application, but ANB contested it and filed suit seeking a declaration that the Ranch Viejo entities were prohibited from constructing on the land any structures or appurtenances associated with the municipal waste facility. The trial court granted summary judgment to ANB, declaring that ANB was a cotenant on the land; that RVVC and RVWM (collectively, Rancho Viejo) had no right to use the land for landfill facilities without ANB's consent and that its right of exclusive use and possession was limited to hunting and grazing; and that as ANB's fiduciary, Rancho Viejo had no legal authority to impair, inhibit, or destroy ANB's benefits from the surface use in the development of the mineral estate. *Id.* at *2–4.

Rancho Viejo argued on appeal that ANB was not entitled to assert the rights of a cotenant, having relinquished the right of possession associated with fee simple ownership. The court of appeals disagreed. Because RVCC in the 1990 cross-conveyance had conveyed to ANB an undivided one-half interest in the disputed tracts "in fee simple," ANB had obtained the right to use and possess the land sufficient to create a cotenancy. The parties' contractual agreement to give Rancho Viejo exclusive use and possession did not change the nature of the tenancy, the court declared, having found no authority supporting the severability of rights associated with the surface estate. *Id.* at *6.

The court went on to hold, however, that the trial court was incorrect that Rancho Viejo's right to exclusive use and possession was limited to hunting and grazing only. The cross-conveyance clarified that the party in possession would not have to account to the other for profits derived from those historical uses, but there was no language restricting the use of the disputed tracts. *Id.* at *9. Further, the court held, the trial court's declaration that Rancho Viejo could not impair ANB's benefits from surface use "in the development of the underlying mineral estate" created obligations broader than those created by the parties' stipulation, which were limited to matters involving Rancho Viejo's exercise of executive rights in connection with mineral operations. *Id.* at *11. Finally, because the summary judgment evidence raised fact issues whether Rancho Viejo's proposed use would prejudice ANB, the court remanded the case to the trial court for resolution of those. *Id.* at *12.

The arrangement between Rancho Viejo and ANB regarding the mineral classified tracts within their ranches, a transparent scheme to keep the surface ownership divided while sharing the benefits of mineral leasing, suggests serious issues that are not addressed here. Given that the principal purpose of the Relinquishment Act, when it was enacted, was to avoid conflict between surface owners and developers of the state's minerals, might a surface owner vested with the exclusive right of use and possession claim (as Rancho Viejo did not go so far as to do here) that an agreement like Rancho Viejo's and ANB's can be avoided afterward because those rights are tantamount to ownership of the soil in the context of the Relinquishment Act? And should a surface "owner" with no right of possession have standing to challenge surface uses because they might conflict with mineral development where that owner has only the right to act as the state's agent in leasing the minerals but no mineral ownership at all? Those questions may be raised and answered by some future court.

Operator's Principal's Mailing of Joint Interest Billings and Revenue Checks Held Sufficient to Support Texas Court's Jurisdiction to Hear Non-Operators' Intentional Tort Claims

Louisiana Delta Oil Company, LLC (Louisiana Delta), a Virginia limited liability company, was the operator of oil and gas wells in southern Louisiana under joint operating agreements whose non-operating working interest owners included Texas residents. Although Louisiana Delta had been headquartered in Texas for several years, Ethan Miller, a Virginia resident, after taking on the company's sole management in 2016, moved its principal place of business to Virginia. In 2018 several non-operators sued the company and Miller in Travis County, Texas, alleging negligence and gross negligence in the operation of the wells and falsification of the reporting of revenues and expenditures. The trial court granted Miller's special appearance challenging the court's jurisdiction of the claims against him, which was reversed in *Wadi Petroleum, Inc. v. Miller*, No. 13-21-00014-CV, 2021 WL 4466320 (Tex. App.—Corpus Christi-Edinburg Sept. 30, 2021, no pet. h.) (mem. op.).

"Under Texas's long-arm statute," the court explained, "Texas courts may exercise personal jurisdiction over a nonresident defendant that 'does business' in Texas," but only if the constitutional requirements of due process are met. *Id.* at *4 (quoting Tex. Civ. Prac. & Rem. Code § 17.042). Due process is met if "(1) the nonresident defendant established minimum [purposeful] contacts with the forum state and (2) the exercise of jurisdiction comports with traditional notions of fair play and substantial justice." *Id.* at *5. Unless the defendant's purposeful contacts with the state are pervasive enough to fairly subject the defendant to the court's jurisdiction generally, "there must be a substantial connection between those contacts and the operative facts of the litigation." *Id.* (quoting *Oil Republic Nat'l Title Ins. Co. v. Bell*, 549 S.W.3d 550, 560 (Tex. 2018)). The issue before the court in this case was whether Miller's contacts with Texas were sufficient to confer the trial court with such specific jurisdiction over the non-operators' various tort claims. *Id.* at *6.

Miller had been actively involved in the company while it was domiciled in Texas and while it had ongoing business relationships with Texas corporations, visiting its office there regularly, the court observed. *Id.* at *8. Given all the activities in which he participated that were purposefully directed at Texas, Miller had fair warning that disputes arising out of the operating agreements might subject him to the jurisdiction of Texas. *Id.* The question, then, was whether his contacts with Texas had a sufficient relationship to the non-operators' claims. Although the court found no substantial connection between those contacts and the plaintiffs' claims for negligence and gross negligence in the operation of the wells, inasmuch as they were concerned with conduct that occurred in Louisiana, where the wells were located, *id.* at *9, it concluded the opposite regarding Miller's alleged intentional torts. Those were principally based on Miller's alleged overreporting of expenses and underreporting of revenues, communicated by sending monthly billing statements and revenue checks to the non-operators at their offices in Texas. Although Miller's actionable conduct in allegedly making misrepresentations to the non-operators may have occurred partly outside of Texas, said the court, the non-operators received and relied on Miller's representations in Texas, and his conduct caused harm within the state. *Id.* at *10. Thus, the court held, the non-operators' intentional tort claims "arose directly from Miller's repeated and ongoing contacts with the State through his contractual reporting and accounting obligations to Texas residents . . . ." *Id.*

Production from Tract Described in but Not Effectively Covered by Lease Did Not Extend Lease's Term

King Operating Corp. v. Double Eagle Andrews, LLC, No. 11-19-00336-CV, 2021 WL 4598819 (Tex. App.—Eastland Oct. 7, 2021, no pet. h.), concerned a 2008 oil and gas lease by Harold and LaJuana Robison that on its face covered land in Sections 25, 26, and 50, Block 3, H&TC Ry. Co. Survey, Scurry County, Texas. Although the Robisons owned 100% of the minerals in the land in Sections 26 and 50, they owned in Section 25 only 50% of the minerals and none of the executive rights. The executive rights governing the Robison mineral interest in the Section 25 land were instead owned by Dwaine and Jo Ann Williams, who leased to the same lessee as had the Robisons.

King Operating Corp. (King) acquired interests in both leases and drilled a well in the Section 25 land but none anywhere else on the Robison lease. After the lease's primary term expired, Double Eagle Andrews, LLC (DEA) acquired a new lease on the Section 26 land, and MEI Camp Springs, LLC (MEI) acquired another on the Section 50 land. When King filed an application for a permit to drill a new well in the Section 26 land under its 2008 lease, DEA protested the application and filed suit seeking to establish its superior title. MEI intervened to establish its title under its lease on the Section 50 land. The trial court granted summary judgment to DEA and MEI, and the court of appeals affirmed.

King and other owners of the 2008 Robison lease acknowledged that the Williams lease, not the Robison lease, covered the Robison mineral interest in the Section 25 land. They argued, though, that because the lease defined the "leased premises" to include all of the land and provided that production anywhere on the leased premises would extend its term, the production from Section 25 extended the lease as to all of the land. The court disagreed. The court could discern no intent by the parties that the term "leased premises" was not used consistently throughout the lease, and the lease referred to rights it granted in the "leased premises" numerous times in ways that could not be effective without ownership of the executive rights. *Id.* at *7. The parties rather intended, said the court, for the term "leased premises" to refer only to those tracts of land in which the Robisons actually conveyed a leasehold interest. *Id.* Because the Robisons did not convey a leasehold interest in the producing Section 25 land, that land was not part of the "leased premises," and the lease's habendum clause only applied to the rest of the land where there was no production to extend the lease's term. *Id.*

Railroad Commission's Denial of Forced Pooling Upheld

In *Ammonite Oil & Gas Corp. v. Railroad Commission of Texas*, No. 04-20-00465-CV, 2021 WL 4976324 (Tex. App.—San Antonio Oct. 27, 2021, no pet. h.) (mem. op.), the court affirmed the district court's order affirming the denial by the Texas Railroad Commission (Railroad Commission) of Ammonite Oil and Gas Corp.'s (Ammonite) application for an order under the Texas Mineral Interest Pooling Act (MIPA), Tex. Nat. Res. Code §§ 102.001–.112, to forcibly pool its leasehold interest in land underlying the bed of the Frio River in McMullen County, Texas, into 16 proposed units with 16 producing wells drilled by EOG Resources, Inc. (EOG).

Ammonite had made an offer to EOG, as MIPA requires, to voluntarily pool its riverbed acreage with EOG's wells. EOG rejected the offer and objected to Ammonite's MIPA application, presenting the expert testimony of a petroleum engineer. In rejecting Ammonite's application after a hearing, the Railroad Commission found, among other things, that Ammonite did not provide survey data or land descriptions to establish the precise acreage to be force pooled; that none of the 16 wells produced hydrocarbons from or drained the riverbed; that Ammonite had agreed at the hearing with a greater charge than the 10% it had proposed in its voluntary pooling offer; and that compulsory pooling would not prevent waste, protect Ammonite's correlative rights, or prevent the drilling of unnecessary wells, one of which circumstances must exist for MIPA to authorize a pooling order. It then concluded that Ammonite had failed to make a fair and reasonable offer to pool as required and that force pooling would not prevent waste, protect correlative rights, or avoid the drilling of unnecessary wells. *Ammonite*, 2021 WL 4976324, at *1–2.

The court of appeals rested its decision to uphold the Railroad Commission order on the conclusion that Ammonite's pooling offer to EOG was not "fair and reasonable," as MIPA requires. In its offer to EOG, Ammonite had proposed a 10% charge for risk. At the administrative hearing, the court pointed out, Ammonite had first asserted that a 10% risk charge was reasonable in an unconventional resource play like the field where EOG had drilled its wells but had then conceded that a higher charge would be fair and reasonable. *Id.* at *5. EOG's expert had testified, to the contrary, that the proposed 10% charge for risk was unreasonably low because a large resource play like the one here requires a large investment in acreage and drilling to be commercially successful and that a 100% charge for risk would be fair and reasonable, and more appropriate. *Id.* This testimony was sufficient, according to the court, particularly in view of Ammonite's failure to present expert or technical evidence to controvert it, to provide a reasonable basis for the Railroad Commission's conclusion that Ammonite's pooling offer was not fair and reasonable. *Id.*

CANADA – OIL & GAS

Matthew Cunningham & Evan Hall
– Reporters –

Canada's Surging Potential: Lithium and Graphite Mining and Their Role in the Electric-Vehicle Supply Chain

With an abundance of high-quality deposits of lithium and graphite, Canada is poised to play an important role in the global shift towards a more sustainable energy future. Globally, countries are committing to achieving carbon neutrality, with many targeting 2050 as the deadline to meet this goal. Integral to this shift is the rechargeable lithium-ion battery, used in both electric vehicles and energy storage. As a result, demand for lithium and graphite, used in lithium-ion batteries, has increased dramatically and is expected to continue to rise in the coming decades. While new and disruptive technologies may impact projections, the World Bank report "Minerals for Climate Action: The Mineral Intensity of the Clean Energy Transition" estimates that global demand for lithium-ion batteries is so great that production of both lithium and graphite will need to increase by almost 500% simply to meet demand by 2050.

Uses of Lithium-Ion Battery Technology

Transportation. The International Energy Agency's (IEA) "Net Zero Emissions by 2050 Scenario" states that more than 50% of all vehicles sold worldwide in 2030 will be electric; over 10 million electric vehicles were sold in 2020, accounting for 4.6% of global vehicle sales. The IEA further estimates that there will be 120 million electric vehicles in use by 2030, an increase from 0.3% to 7% of the global vehicle fleet. However, this number could vary anywhere from 57 to 300 million in the same span, depending on environmental policy decisions made by global governments. In Canada, registration of new electric and hybrid vehicles represented 6.2% of all vehicle registrations in 2020. By 2030, Clean Energy Canada predicts that nearly 50% of all vehicle sales in Canada will be electric.

Energy Storage. In addition to their use as power storage in electric vehicles, lithium-ion batteries are viable options for both decentralized and grid-scale energy storage. Some clean energy sources, such as wind and solar power, suffer from intermittency issues, often at times when their power is needed the most. To mitigate this, energy from these sources needs to be collected and stored. The rapid upswing in the deployment of these technologies critically depends on the equal development of collection and storage capacity for the energy they produce. Lithium-ion batteries are ideal for both grid-scale and decentralized deployment of renewable energy sources due to their widespread availability and ability to charge and discharge energy quickly.

Policy Development

While policy development is in its early stages, Canada has been investing in lithium-ion battery production for a number of years, and saw a renewed effort in 2015 as global demand for lithium began to increase. Canada has approximately 4% of the world's lithium and ranks 10th in world production of graphite, producing 10,000 metric tonnes annually. The Canadian government is advancing initiatives both within Canada and in partnership with the United States to harness the potential of these minerals and take advantage of the emerging North American supply chain for lithium-ion battery technology.

Canada's federal government released "The Canadian Minerals and Metals Plan" in March 2019, aimed at establishing

Canada as a leader in the global mining economy. The plan outlines six strategic directions:

(1) developing infrastructure, regulation, and financial incentives to create a competitive and attractive environment for investment;

(2) developing and adopting innovative science, technology, and best practices;

(3) fostering support for sustainable mineral development within communities;

(4) demonstrating global leadership in the industry through responsible business practices and responsible sourcing;

(5) improving environmental protection; and

(6) continuing to involve and collaborate with Canada's Indigenous populations, consistent with the duty to consult enshrined in section 35 of Canada's *Constitution Act, 1982*, which will be vital to maintaining a sustainable mining industry and advancing the path to reconciliation with Indigenous nations.

The plan's success will depend on both pan-Canadian and international collaboration to develop these critical minerals and establish secure supply chains.

While the Canadian government can make general strategic plans, the specifics of regulation and development of these resources falls under provincial jurisdiction pursuant to the Canadian Constitution's division of powers. Executing the plan will require collaboration between the federal and provincial governments. Some provincial governments, including Alberta, Ontario, and Quebéc, have already followed the federal government's lead on critical minerals by creating strategic plans and advisory councils on critical minerals to assess their viability and address their development within provincial borders. In addition, provincial governments have recognized that existing regulatory regimes will need to be modernized to address the unique challenges posed by the burgeoning lithium-ion battery supply chain.

Internationally, the United States and Canada have collaborated on a number of initiatives demonstrating that each views the other as vital to positioning themselves as world leaders in the clean energy future. The United States and Canada finalized the "Joint Action Plan on Critical Minerals Collaboration" in January 2020, intended to create secure supply chains for minerals deemed vital to national energy independence, including both lithium and graphite. This partnership was further advanced by a revised memorandum of understanding (MOU) entered into on June 24, 2021, between the Department of Natural Resources of Canada and the U.S. Department of Energy which included a bilateral commitment to clean energy. This MOU is in furtherance of the "Roadmap for a Renewed US-Canada Partnership" signed by Prime Minister Justin Trudeau and President Joe Biden on February 23, 2021.

The U.S. government has held stakeholder meetings with U.S.-based miners and battery manufacturers to discuss advancing production of these minerals in Canada and expansion into the Canadian marketplace. Some U.S. battery makers and miners are turning to Canada's high-quality deposits of these vital minerals as a necessary component of the electric-vehicle supply chain.

Mineral Advancement and Development

Lithium. Famously referred to as "the new gasoline" by Goldman Sachs, lithium has become increasingly important in the shift to net zero. Current lithium production practices include brine extraction processes and hardrock mining. These processes are slow and achieving the requisite level of purity required for optimal use in lithium-ion batteries can be challenging. Further, the amount of water required in brine extraction processes, almost 1.9 million litres per metric tonne of lithium, combined with the potential for air, soil, and water contamination raises significant environmental and social concerns as to the viability of these methods as a fully "green solution."

Fortunately, new and innovative extraction techniques are being developed for lithium. These include standalone extraction and processing facilities where lithium can be scrubbed off extracted brine almost instantly, rather than through the traditional use of evaporation ponds, and then reinjecting the extracted brine back into the ground. Other methods include extracting lithium from oil and gas operation wastewater, where it is produced as a byproduct. The latter approach is being pursued in Alberta to take advantage of the area's extensive expertise in oil and gas, as well as preexisting oil and gas infrastructure. However, this method is still in its infancy. There are a number of other early-stage lithium development projects underway across Canada, as well as more advanced-stage openmining projects in Quebéc.

Graphite. Graphite's high conductivity makes it ideal for use in batteries, and it is a vital component of the lithium-ion battery. While graphite enjoys a variety of uses, over 136,000 tonnes of graphite was used in batteries in 2016. Similarly to lithium, the purity of graphite required for use in lithium-ion batteries is also very high. As such, while purer synthetic graphite costs almost five times as much as natural graphite, battery makers are willing to pay. China currently dominates the marketplace for both natural and synthetic graphite with more than 62% of the world market share. Development of graphite production in Canada will be important to establish a North American supply chain and minimize China's influence on the marketplace.

Graphite deposits are primarily located in Eastern Canada in Ontario and Quebéc, and can also be found in certain parts of British Columbia, where mining operations are already underway.

Conclusion

Absent new battery technologies, the transition to net zero depends on lithium-ion batteries, which in turn will require rapid up-scaling of both lithium and graphite production to meet global demand. Both the Canadian federal and provincial governments have recognized the value of rapidly developing lithium and graphite mining and processing, and are actively working towards establishing robust regulatory frameworks and key alliances in order to create a secure and permissive environment for development. Canada, rich with high-quality deposits of both minerals and extensive institutional mining experience, is primed to play an important role in this development.

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