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One Man’s Waste is Another Man’s Treasure: Texas Appellate Court Holds that Produced Water Belongs to Mineral Owners

By Jana Grauberger, Alma Shields, James T. Kittrell and Sam Allen, Liskow

Produced water—a substance traditionally considered to be a useless byproduct of fracing—has recently become a valuable product that can be treated and sold to operators for drilling. As background, many areas in Texas contain shale formations that are dense and have poor permeability. To extract minerals from those formations, operators utilize fracing, which involves pumping certain fluid into a well at a high pressure so that fractures are created in the formations, thereby releasing the minerals that were trapped therein. But more than minerals are released. Water containing certain substances (such as sodium, calcium, potassium, and lithium) that was trapped in the formations alongside the minerals are also released by fracing. The minerals and the water flow to the wellbore as a single product stream, after which they are separated. What remains after the minerals are separated is known as produced water. This substance can be dangerous to the environment, so operators are required to carefully dispose of it—a costly endeavor.

While technology existed that would have allowed produced water to be treated for further use by operators in drilling, doing so was not economically feasible. That is, until the last few years. Recent technology has made the process of treating produced water inexpensive enough that it can be sold to operators for a profit. Produced water can also contain certain critical minerals that can be used for the development of clean energy technologies. Thus, conflicts arose between surface owners and mineral owners over the ownership of produced water. In response, the Texas Legislature passed Texas Natural Resources Code § 122.002 on September 1, 2019, which grants title to produced water to whoever takes possession of it for the purpose of treating it for subsequent beneficial use, unless a conveyance instrument expressly provides otherwise. This statute, however, only applies to instruments executed after September 1, 2019. Conflicts between parties to conveyances executed prior to that date were left unresolved.

One such conflict arose between Cactus Water Services, LLC (“Cactus”) and COG Operating, LLC (“COG”). COG owned the minerals under four leases in Reeves County, Texas executed between 2005 and 2014. Those leases granted COG the exclusive right to produce “oil and gas” or “oil, gas and other hydrocarbons.” Two of the leases limited COG’s right to use water from the premises to only that which was necessary for its drilling operations,” and a third prohibited COG from using any water from the premises without the lessor’s written consent. COG also entered into surface use compensation agreements and right-of-way agreements to facilitate its use of the surface when it transported products and waste from the property. COG utilized fracing in its operations and, since commencing same, was responsible for disposing of produced water produced therefrom. In 2019 and 2020, the property’s surface owners transferred all of their water rights to Cactus, including the right to any water produced from oil and gas wells. After Cactus informed COG of its right to the produced water in 2020, COG filed a declaratory judgment action against Cactus seeking a determination that its leases gave it the sole right to the produced water. Cactus, in turn, asserted a counterclaim against COG claiming that it owned the produced water by virtue of its agreement with the surface owners. The trial court granted summary judgment in COG’s favor, leading Cactus to file an appeal with the El Paso Court of Appeals.

In its opinion in *Cactus Water Services, LLC v. COG Operating, LLC*, No. 08-22-00037-CV, 2023 WL 4846861 (Tex. App.—El Paso July 28, 2023, no pet. h.), the El Paso Court of Appeals held that COG’s leases, when viewed in the context in which they were executed, granted COG the sole right to produced water extracted from the property. The Court began its opinion by looking to the statutory and regulatory definitions of “water” and “produced water” because neither were defined in COG’s mineral leases. The Texas Natural Resources Code, the Texas Water Code, and the Texas Railroad Commission’s rules all defined “oil and gas waste” as, effectively, waste containing salt water or other materials arising from drilling operations. Further, the Water Code and the Railroad Commission’s rules defined “water” as, effectively, usable water percolating below the earth’s surface. The Court viewed those definitions as drawing a clear distinction between produced water and groundwater because produced water fell under the definition of “oil and gas waste,” so it could not also constitute “groundwater.” Additionally, the Railroad Commission’s rules made operators responsible for properly disposing of oil and gas waste to protect usable water, which showed the legislature’s intent to distinguish “produced water” from “water.” Finally, industry practice historically treated produced water as a liability and not an asset, and no surface owners asserted a right to produced water until it was perceived as a substance with value. To grant Cactus ownership of the produced water would have been to give it the “benefit of costs and risks [COG] voluntarily undertook.”

The Court reasoned that COG’s leases were negotiated with that backdrop in mind. Thus, the grant in COG’s leases of “oil and gas” and “oil, gas and other hydrocarbons” must have included the rights and liabilities associated with oil and gas waste, including produced water, and those leases did not express any intent to deviate from that framework. As such, COG’s leases confirmed that COG had the exclusive right to the produced water that was extracted with minerals, and the surface owner’s conveyance to Cactus of the right to the produced water was, thereby, ineffective.

Justice Palafox filed a dissenting opinion arguing that longstanding principles of oil and gas law showed that produced water belonged to surface owners. She reasoned that COG’s leases only granted it rights to “oil and gas” and “oil, gas and other hydrocarbons,” not “water” or “produced water,” and that in the absence of a specific conveyance, water remained part of the surface estate. She also noted that the parties recognizing both water and produced water as being distinct from oil and gas showed that the parties also recognized that produced water fell outside of the grant of “oil, gas and other hydrocarbons.” Justice Palafox was not persuaded by the majority’s conclusion that the parties generally intended to convey all substances that flowed to the wellbore. She viewed that as a “general intent” test, which applies only when conveyances are not clear on what “minerals” encompasses and not when conveyances specifically describe the substances being conveyed. Here, COG’s leases specifically conveyed oil and gas, so, in Justice Palafox’s view, the “general intent” test did not apply. As such, she concluded that COG’s oil and gas leases did not grant it the right to water in any form outside of what was reasonably necessary for the production of its minerals.

Justice Palafox also disputed the majority’s reliance on characterizing produced water as oil and gas waste in concluding that produced water fell within the granting clauses of COG’s leases. Prior Texas precedent held that deeper, mineralized water produced from a well belonged to the surface owner, and Justice Palafox saw no distinction between it and produced water. She believed that water, even when mixed with other substances, remains water. Based on that prior precedent and on the lack of authority distinguishing between types of water owned by the surface estate, Justice Palafox would have concluded that produced water belonged to the surface owner. Further, she argued that the majority should have instead utilized the accommodation doctrine to grant COG the right to use produced water for its oil and gas production while avoiding granting COG ownership of the produced water.

Finally, Justice Palafox disagreed with the majority’s usage of Texas statutes and regulations and industry custom to inform the meaning of COG’s leases. First, only one statute in the Natural Resources Code specifically included “produced water” in its definition of “oil and gas waste,” and that statute was passed after COG’s leases were executed. As such, it could not have formed a point of reference for the parties when executing COG’s leases. Second, Texas regulations only mandated that lessees were responsible for disposing of oil and gas waste—they did not purport to effectuate any transfer of the ownership rights to the oil and gas waste. That being the case, Justice Palafox did not believe the regulations had any role in determining the ownership of produced water. Finally, Justice Palafox viewed the usage of industry custom to inform the meaning of COG’s leases as, effectively, a waiver argument. Under Texas law, a party allowing another party to carry out its statutory, regulatory, or contractual duties with respect to waste disposal does not necessarily reflect an intent to waive ownership rights. And while the majority rewarded COG for the “costs and risks” it undertook disposing of produced water, Justice Palafox argued that COG did not voluntarily undertake those costs and risks—COG was both contractually and statutorily obligated to properly dispose of the produced water.

No petition for review has been filed with the Texas Supreme Court as of the writing of this article, but the time period for Cactus to do so has yet to expire. Subject to further determination by the Texas Supreme Court, this case establishes that for instruments executed prior to September 1, 2019, produced water is owned by mineral owners when those instruments convey “oil and gas” or “oil, gas and other hydrocarbons” without specifically reserving produced water or oil and waste. Of course, all instruments are unique, and certain terms or circumstances could always lead to a different result.

Proposed NEPA Regulations Spotlight Environmental Justice

By Clare M. Bienvenu, Greg L. Johnson, Emily von Qualen and Amy Tomlinson, Liskow

On July 31, 2023, the Council on Environmental Quality ("CEQ") published proposed changes to the National Environmental Policy Act ("NEPA") regulations. The proposed changes are "Phase 2" of the Biden administration's response to the 2020 changes promulgated by the Trump administration. Among changes such as simplified documentation requirements and consolidated decision-making, the Phase 2 changes focus on environmental justice ("EJ"), community engagement, climate change, and ease of permitting for renewable energy projects. Significantly, these changes specifically include "environmental justice" in the NEPA process and provide a definition for the first time. If promulgated, the regulations will codify the Biden administration's emphasis on EJ and may provide greater stability and clarity for persons preparing NEPA analyses.

While EJ has been a requirement in NEPA reviews since Executive Order 12898 was signed in 1994, it has not been specifically included in or defined by regulations. The new proposed regulations would change that by defining "environmental justice" as follows:

> [...] the just treatment and meaningful involvement of all people, regardless of income, race, color, national origin, Tribal affiliation, or disability, in agency decision-making and other Federal activities that affect human health and the environment so that people:
>
> > (1) Are fully protected from disproportionate and adverse human health and environmental effects including risks and hazards, including those related to climate change, the cumulative impacts of environmental and other burdens, and the legacy of racism or other structural or systemic barriers; and
> >
> > (2) Have equitable access to a healthy, sustainable, and resilient environment in which to live, play, work, learn, grow, worship, and engage in cultural and subsistence practices.

40 C.F.R. 1508.1(k) (proposed). This definition matches the definition in Executive Order 14096, signed April 21, 2023, which directed an all-of-government approach to incorporate EJ, including in the NEPA process. And, notably, the definition in the proposed changes is more expansive than the current, working definition used by the Environmental Protection Agency because it adds Tribal affiliation and disability to the list of EJ indicators and explicitly protects from disproportionate and adverse human health and environmental effects, including effects from climate change, as well as cumulative impacts.

CEQ is seeking input on whether to define "communities with environmental justice concerns" in the regulations. This phrase is used throughout the proposed regulations, but CEQ did not propose a definition aside from stating that the term means "communities that do not experience environmental justice as defined in § 1508.1. (k)." CEQ is now specifically requesting comment on whether and how the regulations should define the term.

The proposed regulations also incorporate EJ in to the major steps of the NEPA process:

- **Policy.** CEQ proposes to repromulgate § 1500.2 and add language to specify that NEPA's policy of encouraging and facilitating public involvement should include communities with environmental justice concerns in particular. The proposed regulations also add language to clarify that the policy of identifying and assessing reasonable alternatives should include "alternatives that will reduce climate change-related effects or address adverse health and environmental effects that disproportionately affect communities with environmental justice concerns."
- **Determining the Appropriate Level of NEPA Review.** Under § 1501.3, agencies are directed to determine whether an Environmental Assessment or Environmental Impact Statement is required for the federal action based on whether the federal action is likely to have significant effects. CEQ proposes to add the "degree to which the action may have disproportionate and adverse effects on communities with environmental justice concerns" as a factor to be considered when analyzing the intensity of the effects of a federal action. In the preamble to the proposed regulations, CEQ explains that the factor is included because "communities with environmental justice concerns often experience disproportionate environmental burdens such as pollution or urban heat stress, and often experience disproportionate health and other socio-economic burdens that make them more susceptible to adverse effects." 88 Fed. Reg. 49936.

  Additionally, the proposed definition for "effects" or "impacts" in § 1508.1 clarify that effects include cumulative effects and "disproportionate and adverse effects on communities with environmental justice concerns, whether direct, indirect, or cumulative."
- **Environmental Impact Statement.** CEQ's proposed regulations clarify that the discussion of environmental consequences in an EIS must address the "potential for disproportionate and adverse human health and environmental

effects on communities with environmental justice concerns." 40 C.F.R. § 1502.16(a)(14).

- **Mitigation.** The proposed regulations also require that the lead agency consider mitigation for adverse effects on communities with environmental justice concerns and, where appropriate, incorporate mitigation measures to address or ameliorate significant adverse human health and environmental effects of proposed federal actions that disproportionately and adversely affect communities with environmental justice concerns.

Comments on the proposed regulations are due by September 29, 2023. If promulgated, these changes signal a fixed place for EJ in federal law.

BLM Proposes Revised Regulations for Wind and Solar Rights-of-Way and Leases

By Kathleen C. Schroder and Natalie Boldt, Davis, Graham, & Stubbs

On June 16, 2023, the Bureau of Land Management ("BLM") published a proposed rule that would revise the agency's regulations for wind and solar rights-of-way and leases on public lands in 43 C.F.R. Part 2800. The proposed rule would adjust rental rates and capacity fees for wind and solar rights-of-way, modify the BLM's competitive process for offering lands for lease, and revise the BLM's criteria for prioritizing right-of-way applications. Through the proposed rule, the BLM aims to promote the development of renewable energy on public lands and deliver greater certainty for the private sector.

The Federal Land Policy and Management Act ("FLPMA") requires that the BLM rent public lands at fair market value. The BLM's existing regulations attempted to capture fair market value for wind and solar rights-of-way by imposing a multicomponent fee that was comprised of an acreage rent, capacity fee, and any competitive bids. The Energy Act of 2020 amended the FLPMA to allow the BLM to reduce rental rates and capacity fees for wind and solar projects. The BLM seeks to exercise this authority by revising the rental and fee structure for both new and existing wind and solar rights-of-way in the proposed rule. Most notably, the proposed rule would:

- require the payment of either an acreage fee or a capacity fee, whichever is higher in a given year;
- implement a capacity fee based on wholesale power prices and the actual energy produced by a facility rather than an estimate of the energy that could be generated at a facility;
- implement an acreage fee based on per-acre values for pastureland from the National Agricultural Statistics Service Cash Rents Survey and establish the acreage fee at the beginning of the grant or lease term and then adjust it annually at a proposed 3% percent; and
- include a "Buy American" escalating capacity fee reduction, whereby a greater value of American-made products used in facility construction would result in a greater reduction of capacity fees.

The existing regulations require the BLM to use a competitive process to lease lands within designated right-of-way leasing areas. The proposed rule would give the BLM discretion to use a competitive process both within and outside of designated leasing areas. Under the proposed rule, the BLM could use a competitive process on its own initiative, when nominated or requested by the public, or when there are two or more competing applications.

Additionally, the proposed rule would adjust the BLM's process for interested parties to nominate lands for competitive lease. Under the proposed rule, successful bidders for lands within and outside designated leasing areas would be assigned different statuses reflecting the BLM's need for further evaluation of lands outside of designated leasing areas.

The proposed rule would also change how the BLM prioritizes applications for wind and solar rights-of-way. The BLM explained that the existing rule relied on overly prescriptive screening criteria. The BLM now proposes "holistically" considering factors to prioritize applications, including:

- Whether a project is in an area preferred for wind and solar development;
- Whether a project avoids adverse impacts or conflicts;
- Whether a project conforms with land use plans;
- Whether a project is consistent with laws;
- Whether the project incorporates best management practices; and
- Any other factors identified in BLM guidance.

Additionally, the proposed rule would extend the maximum term of a lease or grant for solar or wind development projects from thirty years to fifty years.

Public comment on the proposed rule was due on August 15, 2023, and the BLM anticipates finalizing the rule by the summer of 2024.

Louisiana State Mineral Board to Consider Retaining Third Party Counsel to Pursue Underpayment of Royalty Claims Associated with Natural Gas Production on State Lands and Waterbottoms

By Brittan J. Bush and Jeff Lieberman, Liskow

The Louisiana State Mineral and Energy Board ("Mineral Board") is the body tasked with overseeing the mineral resources owned by the State of Louisiana. The Mineral Board and its associated staff within the Louisiana Office of Mineral Resources overview various state leases and operating agreements covering state-owned lands and waterbottoms to ensure that the State receives royalties or other funds owed under agreements with mineral lessees and well operators. Traditionally, these tasks are handled internally by the Mineral Board's own staff and counsel. Auditing of royalty payments is left to the Mineral Board's internal accountants. And the Mineral Board's land personnel and internal counsel oversee sending demands and pursuing litigation to recover royalty payments from the State's mineral lessees and well operators.

The Mineral Board's most recent agenda for its July 12, 2023 meeting included an executive session discussion of potentially outsourcing these functions to third-party legal counsel. The agenda specifically states that the Mineral Board will engage in "[a] discussion regarding the potential for the State Mineral and Energy Board to enter into a legal contract with a third party that would pursue claims of underpayments of royalties related to natural gas production on state lands and water bottoms." A decision by the Mineral Board to engage outside counsel to pursue claims for the failure of mineral lessees and operators to timely or correctly pay royalties will signal that the Mineral Board intends to pursue such claims more aggressively in the future. As a result, parties to mineral leases covering state-owned lands or waterbottoms and operators of wells producing from such acreage should be prepared for the potential increase in inquiries and demands from the Mineral Board and be mindful of the unique royalty payment provisions that are often in state mineral leases and operating agreements, which may differ from provisions typically found in standard form mineral leases and operating agreements.

FERC Announces "Watershed" Changes to Interconnection Policy

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

On July 28, the Federal Energy Regulatory Commission ("FERC") issued a final rule ("Final Rule"), which Chairman Willie Phillips calls the most significant change to FERC interconnection policy since the initial policy was put in place nearly two decades ago. FERC expects that these changes will "address interconnection queue backlogs, improve certainty, and prevent undue discrimination for new technologies." Specifically, the Final Rule is "intended to ensure that the generator interconnection process is just, reasonable, and not unduly discriminatory or preferential." The Final Rule will become effective 60 days after publication in the Federal Register.

In 2003, FERC issued Order No. 2003 requiring all public utilities that own, operate, or control facilities used to transmit electric energy to have on file standard procedures and a standard agreement for interconnecting generating facilities larger than 20 megawatts. In the following years, FERC adopted similar policies for smaller generators. However, the recent growth in new and diverse resources attempting to interconnect to the transmission system has highlighted problems within this policy scheme. Specifically, FERC points to "large interconnection queue backlogs and uncertainty regarding the cost and timing of interconnecting to the transmission system." These problems have resulted in increased consumer costs and reliability issues as new generators are unable to connect in an efficient and timely manner. At the end of 2022, there were more than 2,000 gigawatts of new generation and storage awaiting connection in the United States.

In response to the issues highlighted above, FERC is adopting reforms to its pro forma Large Generator Interconnection Procedures and pro forma Large Generator Interconnection Agreement under the Final Rule. These reforms include: (1) implementing a first-ready, first-served cluster study process, including increased financial commitments for interconnection customers; (2) increasing the speed of interconnection queue processing, including major changes to the interconnection study process (discussed in more detail below); and (3) incorporating technological advancements into the interconnection process. Additionally, under the Final Rule, FERC will implement changes to its pro forma Small Generator Interconnection Procedures and pro forma Small Generator Interconnection Agreement.

Due to the size and scope of the changes contemplated, transmission providers and project developers will need to increase their focus on regulatory compliance. Importantly, the Final Rule will eliminate the reasonable efforts standard for completing interconnection studies, by establishing firm deadlines for transmission providers and imposing stiff study delay penalties. Additionally, the Final Rule will require transmission providers to use a standardized and transparent affected systems study process.

While the changes discussed herein represent a "watershed" change to America's power generation connection scheme, both FERC and stakeholders across the country recognize it is merely the first step in what is expected to be a larger regulatory overhaul. For example, the Final Rule does not address the allocation of project costs or long-term and regional transmission planning; however, FERC is already eyeing potential changes in these areas.

Louisiana Coastal Zone Litigation Update: Cameron Parish District Court Grants Summary Judgment on Solidary Liability Issue

By Kelly Ransom, Kelly Hart Pitre

A Louisiana state district court recently granted summary judgment on a critical solidary liability issue in *Parish of Cameron v. Auster Oil & Gas, et al.*, one of forty-two lawsuits ("Coastal Zone Cases") filed on behalf of several Louisiana coastal parishes alleging violations of the Louisiana State and Local Coastal Resources Management Act of 1978 (the "Act").

In *Auster* and the other Coastal Zone Cases, the plaintiffs and interveners ("Plaintiffs") allege separate violations of the 1978 Act by individual defendants who allegedly failed to obtain or adhere to coastal use permits for oil and gas operations and activities dating as far back as the 1930s. Plaintiffs expressly disavow any tort, contract, property, or mineral law claims in their petitions and make clear that the exclusive bases of their claims are the alleged violations of the Act. Though separate violations by individual defendants are alleged, Plaintiffs claim that the separate violations' cumulative impacts damaged the coastal zone area and assert that the defendants are solidarily liable for such damage.

Following a long jurisdictional battle, which was detailed in the Energy Law Advisor's 2020, 2021, and 2022 updates on the Coastal Zone Cases, the U.S. District Court for the Western District of Louisiana remanded *Auster* and eleven other Coastal Zone Cases filed by Cameron Parish back to the Thirty-Eighth Judicial District Court in Cameron Parish, Louisiana earlier this year. Because that district court consists of only one division, the twelve cases were all assigned to Louisiana District Court Judge Penelope Q. Richard. Judge Richard set a November 2023 trial date in *Auster*, as well as a secondary trial date in March 2024, and the parties are currently entrenched in fact and expert discovery.

This summer, the defendants in *Auster* moved for summary judgment on whether the Act authorizes the imposition of solidary liability, a Louisiana concept analogous to "joint and several" liability. In Louisiana, a solidary obligation is never presumed and "arises only from a clear expression of the parties' intent or from the law." La. Civ. Code art. 1796. The defendants argued that the Act "creates individual legal obligations to obtain individual permits for individual uses, and it requires each user to conform its individual conduct to the specific terms of its individual permit covering each individual use." The Act does not provide any basis, according to the defendants, to impose solidary liability. To illustrate the "fundamentally unfair result" of imposing solidary liability under the Act, the defendants explained that, if even the slightest fault is found on the part of a defendant responsible for only a fraction of the activities at issue for only a few years, that defendant would be liable *in solido* for damages—which Plaintiffs claim total $7 *billion*—caused by other entities' operations associated with over 440 wells located across nearly 8,000 acres and occurring over almost a 100-year time span.

Plaintiffs responded by pointing to the Act's shared remedial obligations and the permitting authority's obligation to consider "cumulative impacts" when issuing coastal use permits. They also relied on evidence purportedly showing that the alleged damage is indivisible to argue that the divisibility of damages is an issue of material fact precluding summary judgment. The defendants maintained that the issue before the court was purely legal and reiterated that solidary liability can only arise from a legal obligation shared by the defendants rather than from the Act's remedies or obligations imposed on the permitting authority.

At the July 26, 2023 hearing, Judge Richard granted the defendants' motion from the bench, stating that "[t]he Court agrees that this is purely legal argument. That the defendants do not need to provide any fact evidence to go forward with their motion. I don't find that solidary liability is imposed by the Act." After the parties submitted competing proposed judgments, the court signed Plaintiffs' proposed judgment on August 18, 2023, dismissing with prejudice Plaintiffs' "claims that defendants are solidarily liable for the relief sought." Though the Judgment tracks the court's July 26 ruling, it also states:

> This judgment shall not apply to the solidary liability of parties, persons, or legal entities legally responsible under the SLCRMA for failing to obtain the same coastal use permit when required, or for violating the same coastal

> use permit, and further, shall not apply to any factually indivisible damage caused by two or more parties, persons or legal entities legally responsible under the SLCRMA for failing to obtain a coastal use permit when required, or for violating a coastal use permit.

Whether or to what extent this language narrows the Judgment's application and scope of Plaintiffs' claims remains to be seen. Regardless of whether the *Auster* trial is in November or next March, it is expected to be the first trial in the forty-two Coastal Zone Cases, and the case will undoubtedly continue to be closely watched.

Gathering is Not Transportation – DCOR & Post-Production Costs Under Federal Leases

By Brad Gibbs, Oliva Gibbs LLP

Royalty payments under federal leases are due on production only after it has been placed in "marketable condition." Thus, a lessee is responsible for placing oil and gas in marketable condition without the typical deduction of post-production costs. The four non-deductible components of marketable condition are: (i) compression; (ii) gathering; (iii) dehydration; and (iv) sweetening or treatment. 30 CFR §§ 1206.20, 1206.171. Oil and gas are generally not considered to be in marketable condition at the wellhead (even if they can be sold untreated).

Although the costs of gathering may not be deducted by a federal lessee, certain costs regarding transportation are deductible. However, questions often arise as to whether a particular activity counts as "gathering" or "transportation." Under 30 CFR §§ 1206.10, et seq., transportation does not start until after the Central Accumulation Point ("CAP"), and thus gathering prior to the CAP is not a permitted deduction. In other words, gathering activities typically do not fall within an allowable transportation cost.

The Office of Natural Resource Revenue ("ONRR") defines "gathering" as "the movement of lease production to a central accumulation or treatment point on the lease, unit, or communitized area, or to a central accumulation or treatment point off of the lease, unit, or communitized area that BLM or BSEE approves for onshore and offshore leases, respectively, including any movement of bulk production from the wellhead to a platform offshore." 30 CFR § 1206.20. If an activity falls within this broad definition of gathering, a transportation allowance will not be available.

In the recent case of *DCOR, LLC v. United States Department of the Interior, et al.*, 3:21-cv-00120-N, 2023 U.S. Dist. LEXIS 127814 (N.D. Tex. Jul. 24, 2023), the U.S. District Court for the Northern District of Texas examined certain offshore activities related to the gathering and transportation of oil and gas. Although the *DCOR* decision involves offshore activities, it provides guidance on the occult practice of deducting post-production costs—and specifically unbundling transportation costs—under federal onshore leases.

DCOR owns and operates oil and gas platforms associated with federal leases off the coast of Southern California. DCOR's oil and gas production is initially accumulated and treated on several offshore platforms. The production from these platforms is then transmitted to an onshore facility where it reaches "marketable condition" and moves through an approved royalty measurement point. At issue is whether the movement of production from these offshore platforms to the onshore treatment facility is "transportation" (which is deductible) or "gathering" (which is non-deductible).

The controversy arose when DCOR solicited the ONRR for guidance on how to calculate its transportation allowances. This prompted a federal audit and finding by the ONRR that DCOR had improperly deducted various transportation allowances. The ONRR contended that "gathering does not end until production is measured for royalty purposes," and that DCOR was thus "precluded from claiming transportation allowances upstream of its onshore royalty measurement points, regardless of where its production achieves marketable condition." In other words, as a general rule transportation costs can only be deducted downstream from the royalty measurement point. After the Interior Board of Land Appeals ("IBLA") determined that it lacked appellate jurisdiction, DCOR sought judicial review of the ONRR's decision, which DCOR alleged was arbitrary and capricious.

The district court began its review of the ONRR's decision by noting that federal lessees are required to pay royalties on "gross proceeds," being "the total monies and other consideration accruing for the disposition of oil produced." 30 CFR § 1206.101. Gross proceeds can be measured only on marketable products, and it is incumbent on the lessee to place production in marketable condition at no cost to the government—including the cost of gathering. As noted above, "gathering" is the movement of production from the lease or unit to a CAP off the lease or unit. A "transportation allowance" is deductible from gross proceeds, and is defined as the reasonable, actual costs of moving oil or gas to a point of sale or delivery but specifically excludes gathering costs.

The court agreed with the ONRR that "central accumulation" did not occur until production reached the final onshore treatment facility and the approved royalty measurement point. Thus, the ONRR's distinction between initial treatment on the offshore platforms and final treatment on the onshore facility was not arbitrary or capricious. The court next explained that there is no general rule that the ONRR must permit transportation allowances for the movement of production from platforms to shore.

The court then addressed DCOR's assertion that the longstanding interpretation of the regulations supports that transportation begins at offshore platforms. Citing a preamble to a prior version of the regulations, the court observed that when approval has been granted for the removal of production from a lease or unit for the purposes of treatment or accumulation, no allowances should be granted for costs incurred by a lessee in these instances. *See* 53 Fed. Reg. 1184-01, 1193, 1230-01, 1240 (Jan. 15, 1988). Thus, the ONRR reasonably concluded that the prior regulations foreclosed transportation allowances prior to production reaching the royalty measurement point.

The *DCOR* decision highlights that, under the CFR, transportation allowances are not applicable to gathering activities. The general rule is that transportation allowances may not be deducted upstream from the royalty measurement point. DCOR also serves as a reminder that: (i) courts give a high level of deference to administrative decisions unless they are arbitrary or capricious (a high threshold of reverence); and (ii) seeking the ONRR's guidance on transportation allowances may be a helpful exercise, but may also prompt an unwelcome audit.

Recent Developments in Louisiana Carbon Capture, Utilization, and Storage Laws

By James (Rusty) McCay and Kate Brasseux, Oliva Gibbs LLP

Carbon Capture Utilization and Storage ("CCUS") has recently become the hottest topic in the energy industry. Employment and optimization of this technology have the potential to effect significant economic growth, including creating jobs and revenue in the way of tax credits and other financial incentives in the State of Louisiana and beyond. In terms of its pipeline infrastructure and geographic location, Louisiana, in particular, is poised to become a leader in CCUS in the coming years as this technology develops and as energy policies continue to transition.

The 2023 Louisiana Legislative session included a number of proposed bills relative to CCUS. While many of the proposed bills failed, HB 571 passed and was signed by the Governor as *Act 378*, effective June 14, 2023. Proposed by Speaker Schexnayder, HB 571 adds new provisions to various statutes regarding carbon capture and sequestration and provides much of the framework and guidelines for CCUS in Louisiana.

First, La. R.S. 30:6(H) was added to require the commissioner of conservation to notify the governing authority of any parish included in a completed permit application for a Class V or VI well related to carbon sequestration. This notification to the local governing authority may be made by electronic mail. This notice requirement is also new language in La. R.S. 30:1105 regarding public hearings.

Additionally, Subpart A-3 of Part II of Chapter 2 of Subtitle I of La. R.S. 30:149 was added regarding the distribution of funds from the storage of carbon dioxide. This provision includes requirements for CCUS contracts with the State Mineral and Energy Board. In sum, any revenues paid to the Office of Mineral Resources must be immediately forwarded to the state treasurer to then remit the funds in accordance with the statute, which requires that 30% be given to the Louisiana Mineral and Energy Operation Fund, 30% be given to the governing authority where the permitted property is located and the remainder be deposited into the Louisiana General Fund.

La. R.S. 30:209.2 was also added and it mirrors the addition to La. R.S. 30:149.

There were also additions made to subpart (4)(e) of Subpart A-4 of Part II of Chapter 2 of Subtitle I of La. R.S. 30:209 to require notification to be made to the governing authority of each affected parish when an operating agreement is entered into whereby the state is to receive a share of revenue from the storage of carbon dioxide.

Additionally, La. R.S. 30:1104.1 was enacted to require an environmental analysis as part of the permit application for a Class VI injection well. The environmental analysis has to address specific questions set forth in the statute such as whether the potential and real adverse effects of the proposed activity have been avoided to the maximum extent possible. The environmental analysis should also include a cost-benefit analysis of the environmental impact costs in comparison to the social and economic benefits. Another question that should be addressed in the permit application is whether there are less invasive alternative sites and activities to the proposal and whether any mitigating measures can be taken to offer more protection to the environment.

La. R.S. 30:1107 was amended for clarity. La. R.S. 30:1107.1 is a new addition regarding reporting and record keeping for Class VI wells. This provision requires the owner or operator of a Class VI well to submit quarterly reports to the commission containing any changes to the physical and chemical characteristics of the carbon dioxide, monthly values for injection pressure, flow rate and volume, and annular pressure, and monthly and cumulative volume or mass of the carbon dioxide stream injected. Additionally, the owner or operator of a Class VI well must also provide a report within twenty-four hours of the occurrence of evidence that the injected carbon dioxide stream may endanger an underground source of drinking water, noncompliance with a permit condition or malfunction of the injection system, or failure to maintain mechanical integrity.

La. R.S. 30:1109 has both new and amended language regarding the cessation of storage operations and a limited liability release. This amendment changed the time period from ten years to fifty years for applicability of this provision after cessation of injection into a storage facility; thus, this provision is applicable fifty years after cessation of injection or on a site-specific basis by application of the rules regarding the time frame for a storage operator's post-injection site care and site closure plan. Then, the commissioner issues a certificate of completion of injection operations after meeting the requirements in the list, which has been updated in this Act. The list now reads (a) The reservoir is reasonably expected to retain mechanical integrity; (b) The carbon dioxide will reasonably remain emplaced; (c) The storage facility does not pose an endangerment to underground sources of drinking water, or the health and safety of the public; (d) The current storage operator has complied with all applicable regulations related to post-injection monitoring and the issuance of the certificate of completion of injection operations; and (e) The storage facility has been closed in accordance with all applicable regulations related to site closure.

La. R.S. 30:1110 is a provision regarding the Carbon Dioxide Geologic Storage Trust Fund that was also amended by Act 378. This provision was amended to clarify some of its previous language and require that the secretary of the Department of Natural Resources (under the previous version, this was the treasurer of the state of Louisiana) shall certify to the commissioner the date on which the balance in the fund for a storage facility equals or exceeds five million dollars. Under the previous version of the statute, the phrase "storage operator" was used throughout. That phrasing has been replaced with "storage facility." Subpart "g" was added to allow for a storage operator to receive a certification from the secretary of the Department of Natural Resources once they have contributed ten million dollars to the fund, they do not have to continue contributing unless the fund falls below eight million dollars for that operator.

La. R.S. 30:1112 is also a new provision created by Act 378 regarding notice of geologic storage agreements and recordation. This provision allows for a notice of geologic storage agreement, signed by the grantor who executed the agreement in lieu of recording the agreement. Further, the statute provides that recordation of the notice makes the agreement and any subsequent amendment or modification effective as to third persons. There are specific requirements for what the notice must contain. Additionally, a modification of an agreement is not effective as to third parties unless the parties record a signed amendment to the notice that describes the change. The grantee of any recorded notice of geologic storage agreement must also notify the governing authority of the parish in which the instrument is recorded within thirty days after recordation.

La. R.S. 56:30.5 is a new enactment regarding notice to parish governing authorities. This provision requires an applicant seeking a permit to conduct geophysical or geological surveys for carbon sequestration to notify the parish governing authority where the proposed survey is to be conducted.

Senate Concurrent Resolution No. 63 proposed by Senator Cloud provides for a task force to study and propose recommendations regarding the impact of carbon capture and sequestration projects on communities across the state. This resolution is pending at the Committee on Natural Resources since its referral on June 2, 2023.

During the 2023 legislative session, House Resolution No. 229 by Representative Coussan and Senate Resolution No. 123 by Senators Cortez, et al. were passed to encourage the EPA to take necessary actions to timely review and grant Louisiana's application for primacy over Class VI injection wells. The State of Louisiana received primacy for Class I, II, III, IV, and V injection wells under the Safe Drinking Water Act in 1982. In the fall of 2021, after more than two years of preparation and coordination with the EPA, the Louisiana Department of Natural Resources, Office of Conservation submitted its primacy application to the EPA for the administration of Class VI Injection wells. Finally, in the spring of 2023, the EPA published a proposed rule to grant Louisiana primacy over regulation of Class VI Wells under its already established Underground Injection Control Program. The EPA accepted public comment on Louisiana's application until July 3, 2023. There have been no further developments since the comment period closed. Should the EPA grant the request for primacy, Louisiana would not be the first state to have obtained such authority. The EPA has already granted primacy for Class VI wells to North Dakota and Wyoming. Louisiana is, however, ahead of all other states in the application process, since its application is at the rulemaking level, while other states like Texas and West Virginia are still in the pre-application phase.

IEL's 2nd Excellence in Diversity, Equity & Inclusion Award Reception will honor **Bianca Roberson** (Legal Counsel, Shell USA, Inc.). Register now and join us October 12th!

WHEN: 5:30-7:30 p.m.

WHERE: Holocaust Museum Houston (5401 Caroline St., Houston, TX)

The award presentation will be followed by a fireside chat with honoree Bianca Roberson and The Hon. Tameika Carter (44th District Court).

A Message from IEL

The Institute for Energy Law will begin accepting submissions for the December issue of the Energy Law Advisor on October 2nd, 2023 – Deadline to submit is November 13th, 2023. The ELA welcomes submissions of member news, industry updates, case comments, signature pieces, and featured student articles for consideration. Submissions must be in Word format and conform with other ELA guidelines.

Once again, we would like to thank our IEL publications liaisons – this issue has been a great success and we appreciate your support!

If you are interested in being your firm or company's publication liaison to IEL, please contact Kelly Ransom (kelly.ransom@kellyhart.com) and Emma Espey (eespey@cailaw.org).

MEMBERS IN THE NEWS

IEL Executive Committee Member and Chair of the Academic Outreach Committee, **Frédéric Gilles Sourgens**, was named to lead Tulane University Law School's Center for Energy Law as the James McCulloch Chair in Energy Law. He is formerly the Senator Robert J. Dole Distinguished Professor of Law at Washburn University where he was also Director of the Washburn Oil and Gas Law Center.

IEL Supporting Member Firm, **GableGotwals**, announces the opening of an office in Houston. Located in the heart of Houston's Central Business District at 1100 Louisiana, Suite 5000, the expansion will allow the Firm to continue serving clients across multiple practices and industries in a variety of markets. GableGotwals maintains offices in Tulsa and Oklahoma City, Oklahoma.

NEW MEMBERS

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

6th LEADERSHIP CLASS

The Institute for Energy Law is pleased to announce the 6th Leadership Class. Forty accomplished professionals were selected to take part in the 2023-2024 class. The class consists of attorneys from eight states and Washington, D.C. Their experience in the field ranges from three to thirteen years. The 2023-24 IEL Leadership Class consists of the following individuals:

- Jamie Allen, Modrall Sperling, Albuquerque, NM
- Amadita S. Arrendondo, Infinity Water Solutions, Austin, TX
- Ryan Boutet, Shell USA, Inc., Houston, TX
- Catherine Bratic, Hogan Lovells, Houston, TX
- Jonathan Cohen, Red Stone Resources, LLC, Pittsburgh, PA
- Donald L. Collier, Oliva Gibbs, Houston, TX

NEW MEMBERS, CONT.

6TH LEADERSHIP CLASS, CONT.

- Shawn J. Daray, Jones Walker LLP, New Orleans, LA
- Carter Dickinson, Jackson Walker LLP, Houston, TX
- Mahalia Burford Doughty, Sidley Austin LLP, Houston, TX
- Brandon Duke, Winston & Strawn LLP, Houston, TX
- Chris Dunbar, ConocoPhillips Company, Houston, TX
- Hayes Finley, Womble Bond Dickinson (US) LLP, Raleigh, NC
- Ryan Frankel, McGuireWoods LLP, Houston, TX
- Siobhan Galbraith, SLB, Houston, TX
- Manny Geraldo, Washington Gas, Washington, D.C.
- Megan E. Griffith, Susman Godfrey LLP, Houston, TX
- Ryan Haddad, Reed Smith LLP, Pittsburgh, PA
- Karen J. Herzog, Sitio Royalties, Austin, TX
- Rick Houghton, Smyser Kaplan & Veselka LLP, Houston, TX
- Blake C. Jones, Steptoe & Johnson PLLC, The Woodlands, TX
- Rebecca E. Kennedy, Dentons US LLP, Washington, D.C.
- Aaron E. Koenck, Hall Maines Lugrin, P.C., Houston, TX
- Kayli Gillespie, Elias, Brooks, Brown & Nelson, Oklahoma City, OK
- Ryan P. McAlister, Ottinger Hebert, L.L.C., Lafayette, LA
- Najwan Nayef, McGuireWoods LLP, Houston, TX
- Nirav N. Patel, Kelly Hart & Hallman LLP, Fort Worth, TX
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- Katherine Raunikar, Jordan, Lynch & Cancienne PLLC, Houston, TX
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- Laura Shoemaker McGonagill, Baker Botts L.L.P., Houston, TX
- Cristian Soler, Liskow, New Orleans, LA
- Lindsey F. Swiger, Norton Rose Fulbright US LLP, Houston, TX
- Irina Tsveklova, Weil, Gotshal & Manges LLP, Austin, TX
- Mike Vitris, Beveridge & Diamond, P.C., Austin, TX
- Sydney Weathersby, NiSource Corporate Services Company, Merrillville, IN
- Humzah Q. Yazdani, Weil, Gotshal & Manges LLP, Houston, TX

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- Fabio Dworschak, Miller Nash LLP, Seattle, WA

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- Adriana Merlan, Sadler Law Group PLLC, Houston, TX
- Luke Ohnmeis, O'Melveny & Myers LLP, Dallas, TX
- Robert Pillow, Navigator CO2, Houston, TX

FULL-TIME LAW STUDENT

- Tanya Dutko, University of Tulsa College of Law, Broken Arrow, OK
- Taylor Goldstrohm, West Virginia University College of Law, McDonald, PA

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