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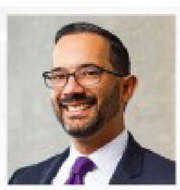

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Supreme Court of Texas Washes Out the "Anadarko Washout"

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The so called "Anadarko Washout" involves a washout of oil and gas leases on undivided working interests owned by non-operating mineral cotenants. This particular species of lease washout is based on two recent cases from the El Paso Court of Appeals – *Cimarex Energy Co. v. Anadarko Petroleum Corp.*, 574 S.W.3d 73, 93 (Tex. App.—El Paso 2019, pet denied)), and *Cromwell v. Anadarko E & P Onshore, LLC*, 676 S.W.3d 860 (Tex. App.—El Paso, 2023 pet. granted), judm't rev'd *Cromwell v. Anadarko E& P Onshore, LLC*, no. 23-0297, slip op. ¶3, available at https://www.txcourts.gov/media/1460583/230927.pdf.

In *Cimarex Energy Co. v. Anadarko Petro. Corp.*, Cimarex Energy Company ("Cimarex") obtained a lease in December 2009 of an undivided 1/6th of the minerals in 440 acres located in Ward County, Texas. The lease was a Paid-Up lease with a five-year primary term. Anadarko Petroleum Corporation ("Anadarko") acquired the remaining 5/6ths of the minerals in the same property by assignment from prior lessees. During the five-year primary term of Cimarex's lease, Cimarex did not commence drilling any wells on the property but instead chose to rely on production from several wells Anadarko drilled in 2011 and 2012. Anadarko failed to account to Cimarex for its 1/6th share of production, and Cimarex brought suit in February 2013. The resulting settlement agreement required Anadarko to pay Cimarex for its 1/6th co-tenant share of the value of production, less Cimarex's 1/6th share of the reasonable drilling completion and operations costs. It also required Anadarko to account to Cimarex on a go forward basis for its monthly share of production, less deductions for Cimarex's share of ongoing operations costs. Anadarko continued to make production payments to Cimarex until December 2014, and thereafter ceased making any payments to Cimarex.

When Passive Production Becomes a Legal Battleground

In August 2011, Cimarex's lessors granted a top-lease covering the 1/6th interest to Petro-Land Group. Anadarko subsequently acquired the top-lease in June 2012. Once the primary term of Cimarex's lease expired in December 2014, Anadarko took the position that Cimarex's lease expired because it required Cimarex drill or operate a well on the property prior to the expiration of the primary term, and Cimarex failed to do so. Both the trial court and the El Paso Court of Appeals agreed with Anadarko that Cimarex's lease had terminated under these facts.

Those courts were not persuaded by Cimarex's arguments that it had perpetuated its lease by paying royalties to its lessors on its share of production from Anadarko's wells, or that Anadarko's co-tenancy accounting to Cimarex under the terms of their settlement agreement was the equivalent of participation in joint development under the terms of a Joint Operating Agreement ("JOA").

In a similar case, *Cromwell v. Anadarko E & P Onshore, LLC*, Cromwell obtained leases covering a small fractional interest in multiple sections of land in Loving County, Texas. Anadarko owned substantial leasehold interests in the same land. Prior to Cromwell's acquisition of leases, Anadarko had already established production, and was the designated Operator pursuant to a JOA with other non-operating working interest owners. After acquiring his leases, Cromwell made multiple requests that Anadarko send him a JOA so that he could participate in Anadarko's development. Anadarko never sent Cromwell a JOA, but it did account to Cromwell as co-tenant once its wells paid out. After payout, Anadarko sent Cromwell joint interest invoices showing Cromwell's revenues and deducted costs.

Anadarko even sent Cromwell an authorization for expenditure for a new compressor on one well, which Cromwell consented to and paid. Nevertheless, years after the primary terms of Cromwell's leases expired, Anadarko took the position that Cromwell's leases had terminated. Anadarko subsequently acquired new leases from Cromwell's lessors. Once again, both the trial court and the El Paso Court of Appeals sided with Anadarko. Those courts held that Cromwell's leases terminated because Cromwell had failed to drill any wells or obtain production, and Cromwell had not participated in joint development of the property pursuant to the terms of a JOA. In deciding both *Cimarex* and *Cromwell*, the El Paso Court of Appeals relied on its prior decision in *Hughes v. Cantwell*, 540 SW.2d 742, 743-44 (Tex. Civ. App.—El Paso, 1976, writ ref'd n.r.e.), and *Mattison v. Trotti*, 262 F.2d 339 (5th Cir. 1959), both of which held that a typical habendum clause requires the lessee named in the specific lease (or presumably, the original lessee's successor) to personally produce oil or gas to perpetuate the lease.

Joint Development Denied: The Cromwell Conflict

The holdings of these cases threatened to destabilize the title of many oil and gas lessees that relied on production operated by third-parties to maintain their leasehold rights. Relying on this line of cases, the United States District Court for the Southern District of Texas went so far as to state "Texas law does not allow a lessee to rely on a co-tenants production of oil to extend the term of a lease." *Fort Apache Energy, Inc. v. Short Og III, Ltd.*, 2022 U.S. Dist. Lexis 130626, *9 (S.D. Tex., July 21, 2022). This led many commentators and practitioners to advise clients that their non-operated leasehold interests were at risk in absence of a Joint Operating Agreement or pooling agreement.

A Doctrine Destabilized: Industry Implications of El Paso's Rulings

On May 23, 2025, the Supreme Court of Texas issued its opinion in *Cromwell*, reversing the El Paso Court of Appeals, and expressly disapproving *Cimarex*, *Hughes* and *Mattison*. The Court's reasoning was simple, and firmly rooted in Texas oil and gas jurisprudence. First, the Court rejected Anadarko's argument that the passive-voice habendum clauses in Cromwell's leases required Cromwell to personally produce because the clauses did not say that, and courts are not at liberty to rewrite agreements. Further, the Court stated that "[n]either habendum clause 'clear[ly], precise[ly], and unequivocal[ly]' requires Cromwell to produce, so we will not imply such a requirement to cause a forfeiture of his interest." *Cromwell v. Anadarko E & P Onshore, LLC*, no. 23-0297, slip op. ¶ 24, available at https://www.txcourts.gov/media/1460583/230927.pdf. In so doing, the Court reenforced its commitment to the rule that special limitations in oil and gas leases must be clear, precise and unequivocal, and that provisions providing for automatic termination may not be implied. This rule is undoubtedly one of the most important tenets of oil and gas lease interpretation. Its consistent application is important to the stability of mineral title in the State of Texas, something which the Court also acknowledged in the concluding paragraph of the opinion (included below).

The Supreme Court's Reset: Bright Lines and Lease Clarity Restored

"We remain faithful to the text of oil and gas leases because doing so provides 'legal certainty and predictability,' values which 'are nowhere more vital than in matters of property ownership, an area of law that requires bright lines and sharp corners.'" *Id*. at ¶ 31.

As a practitioner who regularly represents industry participants in lease termination cases and title disputes, the consistent placement of "bright lines and sharp corners" is greatly appreciated.

Legislative Changes to Federal Onshore Oil and Gas Leasing and Development

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On July 4, 2025, President Trump signed a reconciliation bill (Reconciliation Act) that contains numerous provisions affecting oil and gas leasing and development on onshore federal lands. Some provisions repeal elements of the 2022 Inflation Reduction Act (IRA), while other provisions react to administrative and regulatory efforts that constrain federal oil and gas leasing.

Rollback of the IRA's Increased Royalty Rate on New Federal Onshore Oil and Gas Leases

The IRA had amended section 17(b)(1)(A) of the Mineral Leasing Act (MLA), 30 U.S.C. § 226(b)(1)(A), to increase the royalty rate on new onshore federal oil and gas leases from a minimum of 12.5% to 16 2/3%. Section 50101(a)(1) of the Reconciliation Act repealed this IRA provision and restored section 17(b)(1)(A) of the MLA "as if [the IRA] had not been enacted into law."

The IRA also had established a baseline 16 2/3% royalty for reinstated leases. The Reconciliation Act similarly repealed this royalty rate applicable to reinstated leases.

Importantly, the Reconciliation Act did not undo all of the IRA's changes to the terms of new onshore oil and gas leases. Section 50262(b) and (c) of the IRA amended the MLA at 30 U.S.C. § 226(b)(1)(B) and (d) to increase the minimum bid and annual rental rates for onshore oil and gas leases. The Reconciliation Act left these amendments intact.

Circumscription of the Secretary's Discretion to Lease Lands for Oil and Gas Development

Prior to the Reconciliation Act, the MLA afforded the Secretary of the Interior discretion to lease a given parcel of land for oil and gas development. Specifically, 30 U.S.C. § 226(a) provided that the Secretary "may" lease lands known or believed to contain oil and gas deposits. Courts had interpreted this statutory mandate as affording the Secretary broad discretion to determine whether to lease lands.

Section 50101(d) of the Reconciliation Act eliminated this discretion. The Reconciliation Act replaced 30 U.S.C. § 226(a) with a requirement that the Secretary must lease those lands for which the Secretary receives an expression of interest for leasing. The Secretary must make such lands available for leasing within 18 months of receiving the expression of interest, so long as those lands are designated as open to leasing under the applicable resource management plan (RMP) when the expression of interest is submitted.

The Reconciliation Act also amended 30 U.S.C. § 226(a) to provide that an ongoing RMP amendment "shall not" prevent or delay the Bureau of Land Management (BLM) from offering lands for lease.

Limitation on Oil and Gas Lease Stipulations

Section 50101(d) of the Reconciliation Act amended 30 U.S.C. § 226(a) to prohibit BLM from attaching stipulations or mitigation requirements to oil and gas leases that are not included in the applicable RMP.

Promotion of Quarterly Onshore Oil and Gas Lease Sales

The Reconciliation Act promotes quarterly onshore oil and gas lease sales, presumably in response to the Biden administration's pause on onshore lease sales in 2021 and 2022.

The MLA requires that the Secretary, through BLM, hold lease sales "at least quarterly" in each State "where eligible lands are available." 30 U.S.C. § 226(b)(1)(A). While the Reconciliation Act did not amend the MLA's direction that BLM hold quarterly lease sales, section 50101(c) of the Reconciliation Act separately directs that the Secretary "shall conduct a minimum of 4 oil and gas lease sales of available land" each fiscal year, *i.e.*, October 1 through September 30, in Wyoming, New Mexico, Colorado, Utah, Montana, North Dakota, Oklahoma, and Nevada.

Additionally, section 50101(b)(3) of the Reconciliation Act amended the MLA to define "eligible lands" as "all lands that are subject to leasing under [the MLA] and are not excluded from leasing by a statutory prohibition." This change modifies BLM's longstanding definition of "eligible" set forth in an agency handbook, which defined "eligible" as "available for leasing when all statutory requirements and reviews, including compliance with the National Environmental Policy Act (NEPA) of 1970, have been met." With this change, Congress indirectly rebuked the Biden administration's position that BLM could decline to hold quarterly lease sales when BLM had not completed NEPA reviews prior to leasing.

Furthermore, section 50101(b)(3) of the Reconciliation Act amended the MLA to define "available" lands as "designated as open for leasing under a land use plan developed under section 220 of the Federal Land Policy and Management Act of 1976 (43 U.S.C. 1712) and that have been nominated for leasing through the submission of an expression of interest, are subject to drainage in the absence of leasing, or are otherwise designated as available pursuant to regulations adopted by the Secretary."

To further promote quarterly sales, the Reconciliation Act directed that BLM:

- Conduct any lease sale required by the MLA "immediately on completion of all applicable scoping, public comment, and environmental analysis requirements" under the MLA and NEPA (§ 50101(b)(2)(A));
- Conduct the scoping, public comment, and environmental analysis requirements under the MLA and NEPA "in a timely manner" (§ 50101(b)(2)(B));
- Shall not offer less than 50 percent of available parcels nominated for lease under a given RMP (§ 50101(c)(2)(A)); and
- Shall not restrict parcels offered at a quarterly sale to those located in one BLM field office, unless all nominated parcels are in that one field office (§ 50101(c)(2)(B)). This prohibition prevents BLM from reinstituting a directive in a 2010 BLM instruction memorandum (No. 2010-117) that quarterly lease sales should rotate among field offices in a given state. The effect of this directive had been that BLM offered parcels for lease in given field offices only once or twice a year.

Finally, section 50101(d) of the Reconciliation Act directed BLM to conduct replacement lease sales when a lease sale is cancelled, delayed, or deferred or when less than 25% of acreage offered at a lease sale does not receive a bid.

Elimination of Expression of Interest Fees

The IRA had amended the MLA, 30 U.S.C. § 226(q), to impose a $5 per acre fee on expressions of interest. Section 50101(d) of the Reconciliation Act eliminated this fee.

Restoration of Noncompetitive Leasing

Section 50262(e) of the IRA had eliminated noncompetitive onshore oil and gas leasing. Section 50101(a)(2) of the Reconciliation Act restored noncompetitive leasing.

Elimination of the Royalty on Extracted Methane

Section 50103 of the Reconciliation Act repealed the royalty on methane that the IRA imposed on federal onshore and offshore leases issued after August 16, 2022.

Authorization of Commingling Approvals

Section 50101(d) of the Reconciliation Act amended the MLA, 30 U.S.C. § 226(p), to authorize the commingling of production from two or more federal leases or other sources. The amendment provides some relief from the stringent commingling regulations at 43 C.F.R. Part 3170, Subpart 3173, that BLM adopted in 2016.

The amendment requires BLM to approve commingling applications if the applicant agrees to:

- Install measurement devices for each source;
- Utilize a method to allocate production between sources that "achieves volume measurement uncertainty levels within plus or minus 2 percent during the production phase reported on a monthly basis"; or
- Utilize an approved periodic well testing methodology.

In a press release, the Department of the Interior announced it would initiate a rulemaking to implement this provision.

Adjustment of the Duration of Applications for Permits to Drill (APDs)

Section 50101(d) of the Reconciliation Act amended the MLA, 30 U.S.C. § 226(p), to establish a single, non-renewable four-year term for applications for permit to drill (APDs) approved on or after July 4, 2025. The amendment effectively supersedes BLM's 2024 regulation at 43 C.F.R. § 3171.14(a) establishing a three-year term for APDs.

Energy & Environmental Highlights of the 2025 Louisiana Legislative Session

Benn Vincent, Phyllis Sims, Nick Wise, Sydney St. Perre, and Michael Doggett, Kean Miller LLP

The 2025 Regular Session of the Louisiana Legislature convened April 14, 2025, and adjourned June 12, 2025. The first regular session of the new term saw legislation on several hot-button issues, including 944 bills (696 in the House/248 in the Senate), 24 constitutional amendments, and 751 resolutions and study requests. For fiscal year 2025-2026, the Legislature approved a $53.5 billion state operating budget to fund executive department operations. For more information about the State Operating Budget for the new fiscal year or other general information about the 2025 Regular Session, please see the Louisiana House of Representatives Legislative Services "Session Wrap" summary report, which is available at https://house.louisiana.gov/Agendas_2025/2025RS-SessionWrap.pdf.

The Legislature enacted new laws affecting energy production and environmental regulation. Legislation was passed on several topics including carbon capture and sequestration ("CCS"), oil and gas, renewable energy, water and other natural resources and modifications to certain departments, among others. Many of these laws went into effect on August 1, 2025, while others became effective upon signature of the Governor, or will become effective as of another date prescribed by legislation. This article offers a synopsis of relevant changes that were made to energy, water and CCS laws, as well as the regulatory agencies that enforce them.

Energy and the Department of Conservation and Energy

SB 244 (Act No. 458) significantly changes Louisiana's oilfield remediation statute, Act 312 (Louisiana Revised Statutes § 30:29), starting September 1, 2027. Act 312 applies to "legacy" cases and governs the procedure for the State to maintain oversight over oilfield evaluation and remediation. For a summary of the changes to the legacy lawsuit process, please see: Louisiana Legislature Revisits Act 312 and Oilfield Legacy Lawsuits | Louisiana Law Blog. Starting October 1, 2025, SB 244 also changes the official name of the Department of Energy and Natural Resources to the Department of Conservation and Energy ("DCE" or "Department"), eliminates the office of conservation and transfers those functions to the Department, and organizes DCE into the executive office of the secretary that includes the offices of state resources, legal services, administration, permitting and compliance, mineral resources, enforcement, and energy.

It also creates the Natural Resources Commission as a coordinating body for management of the state's natural resources. DCE is given the exclusive authority to regulate water-dependent activities and to manage and protect the water resources in Louisiana. For a summary of the reorganization of the DCE, please see: Introducing the Department of Conservation and Energy | Louisiana Law Blog.

The new law further establishes an expedited permitting program. It requires advance notice to surface and mineral owners prior to permitting or performing carbon dioxide sequestration related activities. Additionally, SB 244 requires the Department to publish Class VI or Class V applications related to carbon dioxide sequestration on its website, and expropriation of carbon dioxide sequestration pipelines is only permitted for absentee landowners and for pipelines that are common carriers.

HB 459 (Act No. 279) requires certain permits for renewable energy batteries, wind energy, and solar power generation facilities. The new permitting law applies to all uses other than residential property uses. It provides that no battery used for renewable storage facilities shall be installed without the operator first obtaining a permit for installation from DCE. To receive a permit, the applicant must show proof of financial security and a decommissioning plan.

HB 459 also introduces new permitting requirements for wind energy. It states that no onshore wind project shall be commenced without a permit from DCE and similarly requires proof of financial security and a decommissioning plan in order to receive this permit. The term "onshore" is defined to mean "land-based wind turbines and those that are located on inland water bodies."

As for solar power generation facilities, the secretary of DCE has jurisdiction over all persons and property and the authority to perform all acts necessary for enforcement. The new law prohibits anyone from constructing, installing, or operating a solar power generation facility with a footprint of seventy-five or more acres without holding a permit issued by the Department. The Department of Agriculture and Forestry and the Department of Wildlife and Fisheries may submit comments in response to the construction, installation, and operation of any power generation facility to the Department. The location of the facility determines which standards apply. There must be a buffer around the perimeter of each solar power generation facility that includes setbacks and a vegetative barrier to screen the facility from view. For residential property, unless otherwise agreed to by written instrument between the property owner and the facility operator, there shall be a three-hundred-foot setback from the residential property line to the nearest solar device with one of the following: (1) a thirty-five foot deep vegetative barrier composed of new plant material, or (2) a fifty foot deep vegetative barrier composed of natural plant material. For natural and navigable water bodies, a one-hundred-foot setback from the ordinary low water mark to the nearest solar device is required. For public roads, a fifty-foot setback from the edge of the paved road surface to the nearest solar device, with a thirty-five-foot vegetative barrier is required. A parish that adopts solar ordinances may opt out of the siting requirements. Once the submission of the resolution to opt out is passed, the siting standards shall not apply to that parish. This law was effective August 1, 2025.

SB 127 (Act No. 179) provides for development of a permitting program for nuclear generation, expedited processing of environmental permits, and compliance for nuclear generation. The DCE Secretary is authorized to establish a parity program for nuclear power generation and expedite the permitting process for electric public utilities. SB 127 also establishes the application requirements related to same. This law was effective August 1, 2025.

HR 212 contains a request for DCE and the Public Service Commission to study the legality and feasibility of the use of nuclear energy in Louisiana. It urges the agencies to consider the advantages and disadvantages of nuclear energy generation including economic and environmental impacts, workforce impacts for constructing and staffing facilities, evaluations and recommendations on site characteristics and industrial use, environmental and ecological impacts, safety criteria, tax implications at the local and state level, and job creation.

HB 692 (Act No. 462) provides definitions and a policy framework for clean and renewable energy that is affordable and reliable and promotes grid resilience. It requires that energy sources be affordable, reliable, clean, and dispatchable, that they deliver cost savings for commercial and residential customers, and that they include hydrocarbon-generated energy. The new law seeks to promote energy reliability and grid resilience. It became effective August 1, 2025.

HR 265 directs the Louisiana Public Service Commission to explore technology, policy, and cost recovery mechanisms to strengthen the Louisiana electrical grid against electromagnetic threats. It acknowledges that the electric grid of Louisiana is integral to national security and that the high voltage transformers sustaining the Louisiana grid are extremely hard to replace. Due to the devastating potential of a major solar storm, preemptive action to harden Louisiana's grid against such risks is necessary. It specifically considers the possibility for the Gulf of America to be a strategic launch point for an electromagnetic pulse (EMP) attack by hostile nations and terrorist organizations.

SR 195 creates a task force to study and make recommendations relative to policies that promote energy self-regulation, industrial microgrids, and expedited permitting in Louisiana. The task force must develop a written plan, including proposals for legislation, and submit the plan to the Louisiana Senate by March 1, 2026.

HB 600 (Act No. 295), in part, reduces the severance tax rate from 12.5% to 6.5% for oil produced from wells completed on or after July 1, 2025. The Act also makes related reductions to the severance tax rate for incapable, stripper, inactive, and orphan oil wells. The 12.5% severance tax rate is retained for oil produced from a well completed before July 1, 2025. The bill's provisions apply to taxable periods beginning on or after July 1, 2025.

HB 495 (Act No. 284) limits the horizontal well exemption period to 18 months or until payout of the well, whichever comes first, for gas produced from a well completed on or after July 1, 2025. The 24-month exemption period (or until payout of the well) is retained for gas produced from a well completed before July 1, 2025. The exemption period for oil was not changed. The Act applies to taxable periods beginning on or after July 1, 2025.

Carbon Capture and Sequestration (CCS)

HB 691 (Act No. 397) increases regulatory oversight of carbon sequestration activities. The legislation increases the maximum civil penalty for violations under La. R.S. 30:1106 (for underground injection control) from $5,000 to $200,000 per day and per violation. In addition, Act No. 397 imposes more detailed reporting requirements for certain incidents related to carbon injection. At a minimum, reports must now include:

1. A description and the location of the incident;
2. Potential risks to public health, water sources, and land stability;
3. Immediate mitigation steps taken; and
4. A timeline for corrective action.

These reports must be disclosed not only to emergency response teams, but also to local law enforcement, local governing officials, and the public via an official press release. The new law took effect on June 20, 2025.

HB 548 (Act No. 508) establishes a new framework for allocating revenue generated from carbon dioxide storage beneath State property. Prior law made no distinction between sovereign State lands and State agency-owned property, allocating revenue from storage beneath "state-owned land or water bottoms" as follows: 30% to the State's Mineral and Energy Operation Fund, 30% to the parish where the storage facility is located, and the remainder to the State's general fund. The new law replaces "state-owned land or water bottoms" with "public lands as defined in R.S. 41:1701 [i.e., bottoms of navigable waters, banks of shores and bays, arms of the sea, the Gulf of America, and navigable lakes] and dried lake beds that were formerly navigable and remain owned by the state." The legislation then introduces a separate allocation scheme for "injection-based revenue" from carbon dioxide storage beneath property owned by State agencies. This revenue category includes, but is not limited to, injection fees, contractual minimum guaranteed annual payments, and any other revenue derived from injection operations. It excludes revenue collected from bonuses, rentals, pipeline rights-of-way, or other payments for surface use or surface facilities. For injection-based revenue collected on behalf of the Department of Wildlife and Fisheries or the Wildlife and Fisheries Commission, 30% is remitted to the governing authority of the parish where the storage facility is located, and the remainder is deposited into the Louisiana Wildlife and Fisheries Conservation Fund. For all other State agencies, 30% is similarly allocated to the parish, while the remainder goes to the State's general fund.

HB 304 (Act No. 179) provides that expropriation hearings related to carbon capture sequestration activities must be heard in the parish where the subject property is located.

SB 36 (Act No. 407) primarily provides that if any transporter of carbon dioxide has been previously issued a certificate of public convenience and necessity prior to the law's effective date (June 20, 2025), then that certificate shall remain valid. Both SB 36 (Act 407) and SB 73 (Act 414) provided modifications to the final language of SB 244 (Act 458).

SB 73 (Act No. 414) modifies several procedures governing carbon sequestration projects. Most notably, it raises the unitization threshold for carbon dioxide storage projects, requiring written consent from at least 85% of the owners in interest within a proposed storage unit—up from the previous 75%. The law also establishes stricter requirements for initiating eminent domain proceedings related to carbon storage, some of which are:

- Providing written notice of intent to acquire property rights;
- Giving landowners a reasonable opportunity to be present during inspections conducted for appraisal purposes; and
- Engaging in good faith negotiations, including at least five in-person meetings or documented attempts.

Act No. 414 also imposes notice requirements for Class VI and Class V well permit applications.

Water

SB 97 (Act No. 418) creates "CURRENT" – the Coordinated Use of Resources for Recreation, Economy, Navigation, and Transportation Authority – and establishes it as the lead entity for integrated flood control, risk reduction, navigation, water resource management, and infrastructure projects – mainly within inland floodplains and watersheds.

HB 687 (Act No. 217) authorizes the port of New Orleans to utilize public-private partnerships for the development of the St. Bernard Transportation Corridor, a roadway project supporting the Louisiana International Terminal.

SB 94 (Act No. 105) renames the Gulf of Mexico as the Gulf of America in state laws and defines jurisdictional "waters of the state" and "fastlands" (land protected by levees or otherwise not subject to regular inundation). The Act specifies that "waters of the state" do not include "fastlands."

HB 688 (Act No. 395) adjusts the board memberships, leadership roles, term limits, and vacancy procedures for the Southeast Louisiana Flood Protection Authority, both East and West.

Effective Date of Acts

Unless otherwise specified in the legislative text, the effective date of all bills during the 2025 Legislative Session was August 1, 2025.

Infrastructure Projects Win a Victory in the U.S. Supreme Court

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A unanimous U.S. Supreme Court ruled on May 29 that lower courts had overstepped their bounds when reviewing federal agency actions pursuant to the National Environmental Policy Act (NEPA). The decision in *Seven County Infrastructure Coalition v. Eagle County* is expected to have significant implications for how courts handle challenges to infrastructure projects based on federal agency NEPA reviews. [23-975 *Seven County Infrastructure Coalition v. Eagle County* (05/29/25)].

NEPA, signed into law by President Richard Nixon in 1969, is considered one of the foundational environmental laws passed at the beginning of the modern environmental movement requiring federal agencies to take environmental impacts into account when approving projects/permits. NEPA's role in the approval of national infrastructure has grown in recent years as environmental groups have utilized it to challenge and/or delay the approval of large infrastructure projects by pressing arguments that NEPA reviews required federal agencies to consider not only the immediate environmental impacts of a proposed project but also impacts upstream and downstream of the project should it be approved. Further, the courts have increasingly played a far larger and more active role in reviewing the judgment of the federal agencies in determining whether an Environmental Impact Statement (EIS) supported the approval of a project/permit.

Justice Brett Kavanaugh wrote the opinion for the Court reversing the decision of the U.S. Court of Appeals for the District of Columbia, which had found in 2013 the EIS performed by the Surface Transportation Board in reviewing Seven County Infrastructure Coalition's project – to construct and operate a new railroad line which would carry crude oil out of Utah's Uinta Basin and connect to the national railway network, where it would travel to Gulf Coast refineries – did not address impacts from increased upstream oil and gas exploration activities that would result from construction of the project. Ultimately, both liberal and conservative justices agreed with the final decision.

Emphasizing the role that NEPA is to play in the review of projects, Justice Kavanaugh wrote for the majority, "[s]imply stated, NEPA is a procedural cross-check, not a substantive roadblock" and that "[t]he goal of the law is to inform agency decision making, not to paralyze it." The Court wrote that NEPA ensures agencies and the public are aware of the environmental consequences of certain proposed infrastructure projects, but that NEPA's role is purely procedural in this process. Citing prior precedent, the Court found that:

> NEPA "does not mandate particular results but simply prescribes the necessary process" for an agency's environmental review of a project. *Robertson v. Methow Valley Citizens Council*, 490 U. S. 332,350. Some federal courts reviewing NEPA cases have assumed an aggressive role in policing agency compliance with NEPA and have not applied NEPA with the judicial deference demanded by the statutory text and the Court's cases. When, as here, a party argues that an agency action was arbitrary and capricious due to a deficiency in an EIS, the "only role for a court" is to confirm that the agency has addressed environmental consequences and feasible alternatives as to the relevant project. *Strycker's Bay Neighborhood Council, Inc. v. Karlen*, 444 U. S.223,227. Further, the adequacy of an EIS is relevant only to the question of whether an agency's final decision (here, to approve the railroad project) was reasonably explained. Judicial deference in NEPA cases extends to an agency's determination of what details are relevant in an EIS.
>
> The textual focus of NEPA is the "proposed action"—the project at hand—not other separate projects. §4332(2)(C). Courts should defer to agencies' discretionary decisions about where to draw the line when considering indirect environmental effects and whether to analyze effects from other projects separate in time or place. *See Department of Transportation v. Public Citizen*, 541 U. S. 752, 767. In sum, when assessing significant environmental effects and feasible alternatives for purposes of NEPA, an agency will invariably make a series of fact-dependent, context-specific, and policy-laden choices about the depth and breadth of its inquiry—and also about the length, content, and level of detail of the resulting EIS. Courts should afford substantial deference and should not micromanage those agency choices so long as they fall within a broad zone of reasonableness. Even a deficient EIS does not necessarily require vacating an agency's project approval, absent reason to believe that the agency might disapprove the project if it added more to the EIS. Cf. 5 U.S. C. §706. Pp. 6–15.

Consistent with these findings, the Court found that the Surface Transportation Board's determination that its EIS need not evaluate possible environmental effects from upstream and downstream projects separate from the Uinta Basin Railway complied with NEPA's procedural requirements and that, while indirect environmental effects of a project may fall within NEPA's scope, the fact that the project might foreseeably lead to the construction or increased use of a separate project does not mean the agency must consider that separate project's environmental effects.

The Court's three liberal justices—Sonia Sotomayor, Elena Kagan, and Ketanji Brown Jackson—agreed with the outcome of the case but had different reasoning. Writing for the three, Sotomayor, in a concurring opinion, said that such environmental reviews conducted by federal agencies should be limited to the agencies' own expertise. The Surface Transportation Board, which conducted the review in this case, is primarily focused on transportation projects, not oil refining.

"Under NEPA, agencies must consider the environmental impacts for which their decisions would be responsible," Sotomayor wrote. "Here, the board correctly determined it would not be responsible for the consequences of oil production upstream or downstream from the railway because it could not lawfully consider those consequences as part of the approval process."

The Court's ruling gives substantial latitude and deference to the federal agencies to determine the scope of their review of indirect environmental effects and impacts of projects pursuant to NEPA.

NEPA Reform under the One Big Beautiful Bill Act and Revised Agency Procedures

Greg L. Johnson, Clare M. Bienvenu, Emily von Qualen and Colin North, Liskow

On July 4, 2025, President Trump signed into law the "One Big Beautiful Bill Act" ("OBBBA"), which modifies the environmental review process under the National Environmental Policy Act ("NEPA") by allowing a project sponsor to pay a fee for the expedited review of an Environmental Assessment ("EA") or Environmental Impact Statement ("EIS"). NEPA requires federal agencies to assess the environmental impacts of their actions, and this process typically involves preparing an EA, or a more comprehensive EIS. NEPA established the Council on Environmental Quality ("Council" or "CEQ") within the executive office and charged the Council with overseeing NEPA implementation.

Section 60026 of the OBBBA amends NEPA to provide that a project sponsor may, after submitting a description of the project to the CEQ, pay 125% of the anticipated preparation costs of the EA or EIS in return for a review of the EA or EIS under an accelerated timeline. Such review for EAs must be completed within 180 days from the date the fee was paid, and the review for EISs must be completed within one year from the date of publication of the notice of intent to prepare the EIS. CEQ must provide the fee amount within 15 days after the date on which it receives the description of the project. This opt-in fast track is aimed at streamlining NEPA reviews and is the latest action directly affecting NEPA, coming on the heels of President Trump's executive orders and the Supreme Court's decision in *Seven County Infrastructure Coalition*.

In addition, several federal agencies, including the United States Army Corps of Engineers ("USACE") and the Departments of Interior, Energy, and Agriculture, recently issued interim final rules revising and/or rescinding their NEPA implementing regulations and outlining their new NEPA procedures. In particular, USACE issued an interim final rule on July 3, 2025, that rescinded its prior NEPA implementing regulations and replaced them with new regulations found at 33 C.F.R. Part 333. USACE also noted that it would rely on the Department of Defense procedures for civil works purposes. Part 333 applies to both the USACE Regulatory Program (referring to the processing of permit applications under Section 404 of the Clean Water Act, Section 9 of the Rivers and Harbors Act of 1899, and Section 103 of the Marine Protection, Research, and Sanctuaries Act of 1972) and the Section 408 Program, and some key highlights include:

- **Incorporation of the *Seven County Infrastructure Coalition* Court's Clarification to the Scope of NEPA Environmental Reviews** – USACE "may, but is not required to by NEPA, analyze environmental effects from other projects separate in time, or separate in place, or that fall outside of the [USACE's] regulatory authority, or that would have to be initiated by a third party."
- **Alignment with the NEPA Amendments in the Fiscal Responsibility Act of 2023**
  - Time Limits: Generally, an EA must be completed within one year after the date on which the USACE determines the preparation of an EA for the proposed activity is required, and an EIS must be completed within two years after the date on which USACE determines that the proposed activity requires the issuance of an EIS.
  - Page Limits: Generally, an EA must not exceed 75 pages, and an EIS must not exceed 150 pages, both not including citations or appendices.
- **Changes to Public Involvement** – USACE must address only "substantive" comments and need not respond when, for example, the "comment is outside the scope of what is being proposed" or the "commenter misinterpreted the information provided."

The Part 333 regulations also retain USACE's categorical exclusions, which are a category of actions that USACE has determined do not have a significant effect on the human environment and thus do not require the preparation of an EA or EIS. USACE's interim final rule became effective on July 3, 2025 for Regulatory Program permit applications and Section 408 permission requests submitted to USACE on or after that date. Comments on the interim final rule were due by August 4, 2025.

The recent wave of NEPA reforms from the legislative, executive, and judicial branches of the federal government underscore a shift in policy aiming to speed up federal environmental review. While the OBBBA seeks to improve government efficiency, it does not provide a remedy if the agency deadlines are missed, and recent staffing and shifts in agency funding could affect timelines. Industry should stay tuned for further updates to this evolving NEPA landscape.

When Force Majeure Isn't Enough: The Causation Trap That Cost Kinder Morgan $100 Million

J. McLean Bell, McGinnis Lochridge

In case you somehow forgot, the 2021 Valentines Day storm coined "Snovid," "Snowmageddon," or officially labeled Winter Storm Uri, blanketed Texas in snow and ice, even bringing snowfall to Galveston Beach. As temperatures dropped, oil field equipment froze, wells were shut in, and the natural gas needed to generate electricity crashed as the demand for power sky rocketed. According to the Texas Supreme Court, "Texas was fewer than five minutes away from a total grid collapse that would have plunged the state into darkness for weeks, maybe months." *PUC of Tex. v. Luminant Energy Co. LLC*, 691 S.W.3d 448, 455 (Tex. 2024).

At first pass, this event seems like it would constitute a force majeure event, and few natural gas purchasers and suppliers have argued otherwise. But the question in *Freeport LNG Marketing*, was whether a force majeure event *actually caused* Kinder Morgan's failure to purchase gas. The Fourteenth Court of Appeals reversed and remanded the trial court's award of summary judgment to Kinder Morgan, holding it failed to meet its burden that its failure to purchase gas was caused by force majeure.

The $100 Million Question: What Really Happened During Uri?

Kinder Morgan is a natural gas pipeline company that purchases, sells, and transports gas. In 2018, Kinder Morgan and Freeport entered into the industry standard "NAESB" Base Contract which contains the stock provisions for the purchase and sale of natural gas. NAESB is short for North American Energy Standards Board, an industry forum that promulgated the form contract to expedite negotiations and provide industry participants a clear understanding of the obligations of both parties. These base contracts include "check-the-box" general terms that parties agree to such as cover standards, payment methods, and force majeure provisions. Separate Transaction Confirmations are then entered into between the buyers and sellers that set the price, delivery location, and quantity of gas to be sold.

Of course, like any contract, the parties are free to modify the base terms. This is normally completed through an addendum or "special provisions." In the *Freeport LNG Marketing* case, the parties, through special provisions, modified portions of the standardized force majeure language, clarifying that events qualifying as force majeure in the contract only excuse the party from performance "if and to the extent that such cause, event or circumstance *directly* prevents or restricts delivery by Seller or receipt by Buyer of Gas at the applicable Delivery Point."

When Standard Contracts Meet Extraordinary Circumstances

The Transaction Confirmation at issue here was unique in that Kinder Morgan was required to sell gas to Freeport, which Freeport could, at its option, then sell back to Kinder Morgan. When Winter Storm Uri hit, Freeport informed Kinder Morgan of its election to sell back its daily quantity of gas for February 10 through February 22. Kinder Morgan accepted the sellback on some days but rejected it on others because it was curtailing sales itself. Kinder Morgan ultimately disputed eighty percent of the invoiced amount (roughly $100 Million), claiming force majeure. For reference, gas prices during the storm rose well over 100 times daily prices immediately before and after the storm.

Kinder Morgan argued at the trial court that the force majeure event fully excused its repurchase of gas from Freeport. Kinder Morgan further contended that the sellback provision was subject to the force majeure clause in the contract; thus, if Kinder Morgan no longer had an obligation to sell gas to Freeport due to force majeure, then Freeport no longer had a right to exercise the sellback provision.

The relevant clauses in the NAESB, as amended by the special provisions, read as follows:

> 11.1 … [N]either party shall be liable to the other for failure to perform a Firm obligation, to the extent such failure was caused by force majeure.
>
> 11.2 Force Majeure shall include, but not be limited to the following … (ii) weather related events affecting an entire region, such as low temperatures which cause freezing or failure of wells or lines of pipe; (iii) interruption and/or curtailment of Firm transportation … (v) governmental actions such as necessity for compliance with any court order, law, statute, ordinance, regulation, or policy having the effect of the law promulgated by a governmental authority having jurisdiction … provided, however, that any of the previously described causes, events or circumstances shall only constitute Force Majeure if and to the extent that such cause, event or circumstance directly prevents or restricts delivery by Seller or receipt by Buyer of Gas at the applicable Delivery Point. …
>
> 11.3 Without limiting the foregoing Section 11.2, it is recognized that Seller may be subject to governmentally sanctioned or mandated orders or plans for Gas allocation and/or curtailment in the event of a Gas Shortage. It is stipulated that any reduction or suspension of Gas deliveries by the Seller in compliance with such an order or plan shall be deemed to be fully excused … and shall not cause the incurrence of any liability of any kind or type by Seller to Buyer.

Undoubtedly, this was a weather-related event affecting an entire region. Most of the United States experienced sub-freezing temperatures for more than seven days. These cold temperatures impacted wells and lines of pipe like never seen before. FEMA reported that the United States experienced the largest monthly gas decline on record, falling from 90.8 billion cubic feet ("Bcf") of production on February 4, 2021 to 65.4 Bcf on February 17, 2021. In Texas, month-over-month gas production was down 70.1%. Altogether, this created an energy crisis that the government attempted to mitigate through a series of emergency declarations and orders. The Railroad Commission issued an order on February 12th that required deliveries of natural gas to be prioritized for electrical generation facilities.

The existence of all these conditions was ultimately why the trial court found that Kinder Morgan satisfied its burden, as a matter of law, that its refusal to purchase gas was excused by force majeure. Freeport, however, argued there were many fact issues, all of which can be boiled down to: was the existence of the government order, statewide drop in supply, and freezing temperatures the actual reason that Kinder Morgan failed to satisfy its obligations? In other words, Freeport attacked the "causation" element of the force majeure defense, arguing that Kinder Morgan failed to address causation whatsoever in its motion.

The Causation Challenge That Derailed a "Slam Dunk" Defense

On appeal, Kinder Morgan homed in on its compliance with Railroad Commission orders that required gas to be directed to certain tiered recipients, *to the extent possible and necessary*. Freeport argued, and the court of appeals agreed, that Kinder Morgan failed to provide any evidence that its reduction of supply of gas to Freeport was *necessary* to comply with the order. Moreover, the court held that Kinder Morgan failed to demonstrate that any curtailment was necessary in the first instance. Kinder Morgan simply asserted – which the court found conclusory – that it needed to curtail its deliveries to Freeport to satisfy gas deliveries to higher tiered customers. Kinder Morgan did not provide any data to support this argument.

Finally, Kinder Morgan argued that the mere existence of the order justified any reduction in supply to Freeport, pursuant to Section 11.3 of the parties' agreement. But the court rejected this argument, reasoning that, while there may have been an event or condition that qualified as a force majeure under the NAESB contract, Kinder Morgan failed to conclusively prove that the event or condition was the actual cause of its failure to purchase and sell gas. Therefore, the court reversed and remanded, holding summary judgment was improper.

This case stands for the proposition that parties must prove a casual nexus between the force majeure event and the failure to perform. Freeport creatively attacked causation, questioning whether the order required 100% curtailment to Freeport, whether Kinder Morgan's actual gas supply necessitated curtailment, and if so, what percentage of curtailment was necessary. These issues are difficult to prove as a matter of law at the summary judgment stage, but the trial court's ruling would have had a stronger chance at being upheld had Kinder Morgan provided the court with data to support its argument, such as its Electronic Bulletin Board and volume accounting data.

The Evidence Dilemma: Why Data Can Be Your Best Friend or Worst Enemy

The Electronic Bulletin Board and volume accounting data would have provided the court with a better picture of the volume of gas at Kinder Morgan's disposal, who it allocated that gas to, and the Railroad Commission category that the counterparty fell within. For those reasons, providing that information would have been helpful. But producing this data has its drawbacks, too. Specifically, this data opens the door to other potential issues savvy lawyers will identify, *e.g.*, did Kinder Morgan redirect gas supply to higher priced markets, did Kinder Morgan prioritize parties with gas daily pricing or first of month pricing, or prioritize its baseload customers versus spot deals, and how much gas did Kinder Morgan sell under no-notice contracts?

A recent jury verdict underscores just how fact-intensive and case-specific force majeure defenses can be. While Kinder Morgan's defense failed at the summary judgment stage due to a lack of evidence on actual cause, Marathon Oil Company prevailed on the same issue at trial by persuading a jury that Winter Storm Uri "prevented Marathon from delivering [gas] or made Marathon's delivery impracticable." *See* Verdict, *Marathon Oil Company v. Koch Energy Services, LLC*, No. 4:21-CV-01262 (S.D. Tex. May 5, 2025), ECF No. 301.

Beyond Uri: What This Means for Your Next Force Majeure Strategy

The difference between these outcomes illustrates that parties must tailor their arguments and supporting data to meet the evidentiary burdens imposed by any NAESB special provisions. Questions remain whether a party must prove full and complete causation – and how damages should be calculated when a party's non-performance was only partially caused by a force majeure event. For example, what if a party reasonably, but mistakenly, prioritized a counterparty that it thought was serving human needs customers? Nitpicking causation, and effectively how a party complies with a government order during a historic gas supply shortage, seems inconsistent with the certainty the NAESB forum envisioned, but adding special provisions that change the stock language has this impact. The lesson is clear: parties need to consider the evidentiary burden their special provisions will create at trial. Proving absolute causation may not be easy.

PHMSA Issues Advance Notice of Proposed Rulemaking Seeking Stakeholder Comments Related to Repair Criteria for Hazardous Liquid and Gas Transmission Pipelines

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On May 21, the Pipeline and Hazardous Materials Safety Administration (PHMSA) submitted an advance notice of proposed rulemaking (ANPRM) to the Office of the Federal Register (publisher of the *Federal Register*) seeking public comment on updates to repair criteria for hazardous liquid and gas transmission pipelines across the United States. PHMSA is seeking stakeholder feedback to identify opportunities to improve the cost-effectiveness of its repair requirements for gas transmission (49 CFR Part 192) and hazardous liquid or carbon dioxide (49 CFR Part 195) pipelines. By submitting this ANPRM, PHMSA is recognizing the need to update its pipeline safety regulations as they relate to pipeline repair criteria, as many of these regulations have not been updated in 20 years and have not kept up with modern repair technologies. Additionally, PHMSA is seeking stakeholder feedback on authorizing risk-based inspection procedures for determining the inspection interval for in-service breakout tanks under Part 195.

Currently, PHMSA's remediation standards for gas transmission lines under Part 192, and for hazardous liquid and carbon dioxide pipelines under Part 195, address the remediation of anomalies through prescriptive regulations and through the Integrity Management requirements for those segments of pipeline that pose risk to "high consequence areas" (HCAs). While these two approaches to remediation are credited for the downward trend in pipeline incidents, the regulations have not been updated in several years, a delay that may lead to barriers to innovation, technological development, and other safety-enhancing industry practices.

PHMSA did address Part 192 anomaly remediation following the San Bruno incident in its August 24, 2022 final rule, which focused specifically on certain high-risk anomalies in HCAs by updating repair criteria and remediation timelines in Subpart O and touched on some remediation changes under Subpart M for those areas beyond the HCAs. However, some of those amendments have been remanded for further consideration following litigation. As a result, PHMSA is seeking to conduct a more holistic review of its repair criteria.

In addition to the proposed changes to hazardous liquid and gas transmission pipelines, PHMSA is seeking comment on 49 CFR § 195.432, which prescribes the default annual inspection requirements for in-service breakout tanks associated with hazardous liquid pipelines. This revisits a previous proposed rule published by PHMSA, updating the reference to American Petroleum Institute (API) Standard 653, *Tank Inspection, Repair, Alteration, and Reconstruction*, Third Edition, including Addendum 3 and Errata, 2008, **except** (*emphasis mine*) for Section 6/4/3 on Risk Based Inspections (RBI). API then argued that use of RBI technology strengthened the standard by ensuring that those using risk-based inspection intervals meet the most stringent requirements by utilizing the best available and safest technologies.

Finally, a review of PHMSA's repair criteria and associated timelines is consistent with the recent directive from President Donald Trump in his Executive Order (EO) 14192, "Unleashing Prosperity Through Deregulation," as well as EO 14154, "Unleashing American Energy," and EO 14156, "Declaring a National Energy Emergency," which, combined, seek to alleviate regulatory burdens and promote the expansion of energy infrastructure.

The ANPRM includes a number of topics for consideration that cover general anomaly repair criteria and timelines, topics covering repair criteria and remediation timelines specific to carbon dioxide and hazardous liquid pipelines, topics covering the same for regulated gas transmission pipelines, and topics related to in-service Part 195 regulated hazardous liquid breakout tanks.

The ANPRM is available in the *Federal Register*, and a version has been posted on the PHMSA website under Docket No. PHMSA-2025-0019. Stakeholders had until July 21 to file their comments.

In reviewing the public comments submitted to PHMSA, it is clear that stakeholders approach the proposed updates to repair criteria from markedly different perspectives, though all profess a commitment to improving pipeline safety. The Pipeline Safety Trust (PST) urges PHMSA to ensure that any revisions preserve, if not strengthen, safety protections and avoid becoming a vehicle for deregulation. PST emphasizes the need for clarity in terminology—advocating for "response criteria" over "repair criteria"—and warns against weakening recently amended requirements for gas transmission lines. They also call for greater public transparency, including free public access to incorporated industry standards, and for PHMSA to adopt clear, prescriptive timelines for hazardous liquid and CO_2 pipeline anomaly evaluations.

By contrast, the major industry trade associations—representing hazardous liquid, gas transmission, and midstream operators—support regulatory modernization that they contend would align integrity management programs with technological advancements, operational experience, and risk-based decision-making. These groups argue that current prescriptive repair rules require the remediation of non-injurious anomalies, leading to unnecessary excavations, increased operational risk, and significant costs without corresponding safety benefits. They propose expanding the use of engineering critical assessments, recalibrating dent and corrosion criteria, adopting failure pressure-based decision-making, and permitting risk-based inspection intervals for breakout tanks. The industry also seeks to harmonize regulations across Parts 192 and 195, and to consolidate certain repair timelines to allow for more efficient planning and resource allocation.

Together, these comments frame the core policy tension that PHMSA must navigate: balancing the flexibility operators seek to deploy, modern assessment tools and risk-based practices with the assurance, urged by safety advocates, that changes will not dilute the protective intent of existing standards. The resulting rulemaking will need to reconcile these positions in a manner that upholds safety, promotes transparency, and allows innovation to enhance the integrity of the nation's pipeline infrastructure.

Making a Splash in the Courts: The *Cactus* Decision

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In a landmark decision, the Supreme Court of Texas held in *Cactus Water Services, LLC v. COG Operating, LLC* (*Cactus Water Servs., LLC v. COG Operating, LLC*, No. 23-0676 (Tex. June 27, 2025)) that, absent an express reservation, produced water belongs to the operator of an oil and gas lease. When presented with a case where both the oil and gas operator and a third party who contracted with the surface owner claimed ownership of the produced water, the Court determined that under the typical deed or lease language conveying oil and gas rights, produced water is a part of the conveyance or lease, even though not expressly addressed. *Id.* at 29. However, the Court left open the possibility for surface owners to reserve ownership of produced water, potentially turning the tide in future lease negotiations. *Id.*

I. Background

Between 2005 and 2014, COG Operating, LLC ("COG") acquired four hydrocarbon leases from two different surface owners in the Permian Basin (collectively, the "Leases"). *Id.* at 4. The Leases granted the right to explore for, produce, and keep "oil and gas" or "oil, gas, and other hydrocarbons," with variance in phrasing. *Id*. Operations were targeted in the Delaware Basin subregion of the Permian Basin. The principal method of production was through hydraulic fracturing, which involves injecting pressurized fluid, proppants, and chemicals into the rock to release trapped hydrocarbons. *Id.* at 5-6. A portion of the injected fluid returns to the surface, with varying substances mixed in with the fracking fluid, from which COG separates the oil and gas. *Id.* at 6. The remaining substance, known as produced water, is subsequently disposed of, as it can be harmful to human health and the environment in its current state. *Id.* at 7.

In 2019 and 2020, the surface owners of the Leases executed produced water lease agreements ("PWLAs") with

Cactus Water Services, LLC ("Cactus"). *Id.* at 11. The PWLAs conveyed all right, title, and interest in and to water from oil and gas producing formations and flowback water produced from oil and gas operations in the land covered by the Leases. *Id.*

Cactus informed COG of its claim under the PWLAs in March 2020. *Id.* at 12. COG responded by suing for a declaration that COG, not Cactus, owns and has the exclusive right to possession, custody, control, and disposition of its production stream, including the produced water. *Id*. Both the trial and appellate court held in favor of COG. *Id.* at 13.

II. Differing Opinions

On review, Cactus and COG had differing conclusions on why *they* owned the produced water. COG contended that under Texas law and long-standing practice, the language used in the Leases to convey to them oil and gas rights included liquid waste byproducts incorporated with the hydrocarbons, absent any express reservation or exception. Therefore, as no such reservation or exception was included in the Leases, they were the true owners of the produced water. *Id.* at 2. Cactus, however, contended that once the hydrocarbons were separated, the remaining watery mixture was surface wastewater. *Id*. Surface/ground water is owned by the surface owner, absent any express conveyance of water rights. *Id*. Because there was no prior conveyance of water rights, the surface owners of the land covered by the Leases owned the produced water and had the right to convey the same to Cactus under the PWLAs.

III. The Supreme Court Weighs In

Presented with the question of who owns produced water under an oil-and-gas conveyance that does not expressly address the matter, the Supreme Court of Texas ultimately held that the operator, not the surface owner, owns produced water.

In its June 27, 2025 opinion, the Texas Supreme Court held that Cactus' argument rested on a "seductively simple" proposition, asserting that surface owners retain ownership of produced water merely because it contains water molecules. *Id.* at 21. The Court examined the definition of "water," and considered how "produced water" might fall within that scope (Water, unlike oil and gas, is not considered part of the mineral estate and remains part of the surface estate subject to the mineral estate's implied right to use the surface as reasonably necessary to produce and remove minerals). *Id*. Cactus supported its argument with cases such as *Edwards Aquifer Authority v. Day* (369 S.W.3d 814, 832 (Tex. 2012)), *Robinson v. Robbins Petroleum Corp.* (501 S.W.2d 865, 867-68 (Tex. 1973)), and *Sun Oil Co. v. Whitaker* (483 S.W.2d 808, 811 (Tex. 1972)), all of which affirm that a landowner owns groundwater under its land. However, the Court found these precedents inapplicable, noting that they focus on ownership of groundwater in its original place found or through water wells for use of water, and not as a byproduct of oil and gas production.

The Court relied on several key distinctions between water and produced water. First, produced water cannot be defined as 'water,' as it cannot be handled in the same manner. Produced water is an oil and gas byproduct, also referred to as liquid waste, and is a regulated substance which must be handled and disposed of properly. The characteristics of produced water have been described as "hazardous, even toxic," and the handling of such waste is highly regulated and requires appropriate permits and infrastructure. *Id*. at 22. Comically, produced water has been identified as a contaminant, and, as a result, should be kept separate from surface and subsurface water (16 TEX. ADMIN CODE E §§ 3.8(a)(26) ("Oil and gas wastes -- Materials to be disposed of or reclaimed which have been generated in connection with activities associated with the exploration, development, and production of oil or gas or geothermal resources… The term 'oil and gas wastes' includes, but is not limited to, saltwater, other mineralized water, sludge, spent drilling fluids, cuttings, waste oil… and waste generated in connection with activities associated with gasoline plants, natural gas or natural gas liquids processing plants, pressure maintenance plants or repressurizing plants…"), (b) ("No pollution. No person conducting activities subject to regulation by the commission may cause or allow pollution of surface or subsurface water in the state.")).

Second, the Court emphasized the principle that "waste and hydrocarbon production go hand in hand." *Cactus* at 19. The Court cited to *Brown v. Lundell* (344 S.W.2d 863, 866-67 (Tex. 1961)), wherein the separation and disposal of oil and gas wastewater was deemed necessary and incident to the production of oil and gas. *Cactus* at 20. Importantly, COG's tank batteries can only separate and store up to 24 hours' worth of produced water, which must then be handled and transported elsewhere for production to continue. *Id.* at 8. Disposal of such waste has been an unwanted, but vital, part of oil and gas production, and the Court notes that applying water-use limitations to produced water would only frustrate, not facilitate, the production of minerals. *Id.* at 8, 24. As noted, to facilitate production, produced water must be swiftly handled and disposed of, and the lack of infrastructure operated and owned by Cactus (along with most surface estate owners) would make production next to impossible. The Court leaned on this argument in confirming that the right to produce hydrocarbons necessarily encompasses the right to produce and manage the resulting waste. *Id.* at 18.

Finally, the Court rejected Cactus' oversimplified argument that produced water qualifies as 'water' simply because it contains water molecules. As previously discussed, produced water and water are not interchangeable, despite sharing some chemical properties (*e.g.*, both water and produced water may contain H_2O molecules, along with a plethora of similar and dissimilar molecules). To further prove this point, the Court referenced the Brief of Amicus Curiae Permian Basin Petroleum Association at 8-9, which listed substances such as blood plasma, vodka, and concrete, each of which contains water molecules, but is not considered 'water.' *Cactus* at 23. While extreme, these examples underscore the Court's point: the mere presence of water molecules does not render produced water as 'water.' Produced water and water are treated differently because they *are* different. The Concurring Opinion also contends that raising the issue of ownership based on the nature of the produced water is unhelpful to the overall analysis, as it is clearly both water and waste. *Cactus Water Servs., LLC v. COG Operating, LLC*, No. 23-0676 (Tex. June 27, 2025) (Busby, J., concurring). "The fluids include groundwater originally belonging to the landowners, and they are also classified by statute and rule as oil-and-gas waste, which the lessee has a duty to handle and dispose of safely." *Id*. The focus should not be on the nature of the produced water, but on whether the landowners leased the groundwater to the lessee. *Id*. To this, the Concurrence agrees with the Majority Opinion: the incidentally produced subsurface water was included in the Leases' hydrocarbon conveyance. *Id*.

IV. Concurrence

The Concurring Opinion emphasized that the Majority's holding is a narrow one and noted that this case did not resolve three key issues.

First, the Majority Opinion did not decide surface owners' rights to contract differently as to the ownership of groundwater produced and subsequently separated from hydrocarbons. For this, the Concurrence references Section 122.002 of the Texas Natural Resources Code. *Id*. at 3-6. This Section creates default rules for ownership of fluid oil and gas waste when a contract does not provide otherwise. Specifically, the statute provides that ownership of the fluid oil and gas waste changes hands, not at separation of the fluid and the hydrocarbons, but when it is used by or transferred to a person who takes possession of it for the purpose of treating it for a subsequent beneficial use. TEX. NAT. RES. CODE § 122.002(1). Therefore, a surface owner could contract with the lessee to retain ownership of the groundwater component of fluid oil and gas waste. However, the surface owner would then be charged with the safe disposition of said groundwater component.

Second, the Court did not address ownership of unleased minerals or other non-hydrocarbon substances that may be produced along with leased minerals. The Leases at issue in this case only conveyed "oil and gas" or "oil, gas, and other hydrocarbons." No non-hydrocarbon minerals were leased, such as salt or potash. *Cactus Water Servs., LLC v. COG Operating, LLC*, No. 23-0676 (Tex. June 27, 2025) (Busby, J., concurring) at 5. Could this mean lost economic opportunity for lessors?

Third, the Concurrence states that the mineral lessee's obligations to the landowners as to the leased groundwater were not addressed. It is unclear whether the lessee owes royalties on leased produced groundwater. If they do not owe royalties, it is unclear how the parties should account for any profit or loss realized from the beneficial reuse or disposal of the produced groundwater. Finally, it is unclear whether any implied covenants are due to the lessor with respect to the management of water, given that the leases do not expressly address this issue. *Id*. at 6-7.

V. Conclusion

The Supreme Court of Texas has ruled that 'produced water' and 'water' are not one and the same. Produced water is incident to the production of oil and gas in hydraulic fracturing; therefore, granting the right to produce hydrocarbons necessarily encompasses the right to produce and manage the resulting waste, including produced water. *Cactus Water Services, LLC v. COG Operating, LLC* relies on longstanding practices in the oil and gas industry, the current statutory scheme, and a lack of express reservation or exception in the Leases in reaching this conclusion. However, the Court makes it clear that this holding does not prohibit surface owners from reserving water incidentally and necessarily produced with hydrocarbons. Rather, the Court instructs surface owners that such a reservation must be express. With recent technological advances in the recycling of produced water for reuse in industrial processes and irrigation of non-food crops, together with the questions presented in the Concurring Opinion, this likely is not the last time you'll see produced water making a splash in Texas courts.

Murky Waters: Wading Through Texas Law and The Future of Produced Water

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Texas produced water has transformed from waste to valuable resource following the Supreme Court's recent *Cactus Water Services v. COG Operating* decision clarifying ownership rights. New regulations promote reuse and disposal alternatives as drought conditions worsen and disposal wells face increased scrutiny. This shift drives innovation in water recovery, reuse technologies, and lithium extraction, making adaptation speed crucial for operators seeking competitive advantage.

I. Introduction

Texas produces more than just oil and gas. Every day, millions of gallons of produced water are generated as a byproduct of oil and gas production. Once viewed strictly as a waste product, produced water is now at the center of a growing conversation about resource recovery, sustainability, and innovation. Adding to the ongoing discussion, the Texas Supreme Court issued a landmark decision in June in the case of *Cactus Water Services, LLC v. COG Operating, LLC*, No. 23-0676 (Tex. June 27, 2025), ruling that under the typical deed or lease language conveying oil and gas rights, produced water is a part of the conveyance, even though not expressly addressed.

While *Cactus v. COG* aligned with existing industry practices, it likely signaled the beginning of a broader wave of legal disputes over the ownership and use of produced water. This Article will explore the history of produced water as a byproduct of oil and gas production and examine Texas' growing water challenges. This Article will also discuss the potential for extracting valuable minerals from produced water and highlight emerging alternative uses for this once-overlooked resource.

II. Background

The concept for fracking dates back to 1862 but was not popularized until the beginning of the 21st century, accompanied by innovations in fracking fluid and horizontal drilling. *See* Melissa Denchak, *Fracking 101*, Nat. Res. Def. Council (Apr. 19, 2019). Hydraulic fracturing, in simple terms, involves the blasting of fracking fluid into a horizontal well at a pressure high enough to create new fractures or open existing ones in the surrounding rock, to allow the oil or gas to flow back to the surface. *See id*. Fracking fluid is typically a mixture of sand, water, and chemicals. *Produced Water: A Comprehensive Overview*, Select, https://www.selectwater.com/produced-water/ (last visited Aug. 14, 2025) (noting common additives include biocides, surfactants, and friction reducers). After it is injected and returns to the surface through the well, the hydrocarbons are separated, any recovered water is stored, and the remaining fluid – or produced water – is then taken to facilities to be disposed of or treated. *See* Jackie Benton, *Recycling Fracking Water*, Fiscal Notes, Tex. Comptroller (Oct. 2015), https://comptroller.texas.gov/economy/fiscal-notes/archive/2015/october/fracking.php.

Produced water under Section 122.001(2) of the Texas Natural Resource Code is defined as fluid oil and gas waste. *See* Tex. Nat. Res. Code § 122.001(2). Because of such designation, the handling of produced water requires appropriate permits, infrastructure, and regulated disposal, which comes with burdensome expenses and potential liability on behalf of an operator-lessee. *See id*. at § 81.0531 (authorizing the Texas Railroad Commission ("RRC") to impose penalties up to $10,000 per day per violation related to improper disposal). Under Statewide Rule 46 covering fluid injection into productive reservoirs, or injection wells, a permit is required prior to any injection. 16 Tex. Admin. Code § 3.46. During the permitting process, a notice and opportunity for a hearing shall be provided to the government and any affected persons, and a significant amount of information must be provided to the RRC. *See id*. This rule also sets forth the requirements for the injection wells. *See id.* The more popular method of disposal of produced water is into disposal wells, which are governed by Statewide Rule 9. 16 Tex. Admin. Code § 3.9. This rule states that every applicant who proposes to dispose of saltwater or other oil and gas waste into one of these wells must obtain a permit from the RRC, and the disposal shall be in line with the requirements set forth in Statewide Rule 9. *See id.*

The Texas Legislature strives to keep rules current. This past legislative session, the Legislature passed a series of bills aimed at modernizing the handling and reuse of produced water, which are set to go into effect September 1, 2025. *See* Ashleigh K. Myers & J.C. Freeman, *Water, Reused: Texas Reshapes Liability and Regulatory Rules on Produced Water, Leaves Ownership Questions Unanswered*, Pillsbury (June 9, 2025). To name a few, House Bill 49 relates to the treatment and beneficial use of fluid oil and gas waste and adds new tort immunity for entities involved in the beneficial use. *See id*. House Bill 4426 changes the permit duration and renewal processes for commercial surface disposal facilities, establishing clearer guidelines. *See id.* Finally, Senate Bill 1145 authorizes the RRC to issue permits for the land application of produced water, tasking the RRC with establishing clear regulatory standards that are expected to address application methods, water quality thresholds, monitoring protocols, and site-specific environmental conditions. *See id*. Not only is the Texas Legislature taking aim at the legislative framework, they are also funding a large study based out of Texas Tech University, called the Texas Produced Water Consortium ("Consortium"). The Consortium has the purpose of bringing together information and resources to study the economics and technologies related to the beneficial uses of produced water, including environmental and public health considerations. *See* Rusty Smith et al., Beneficial Use of Produced Water in Texas, Texas Produced Water Consortium—Report to the Texas Legislature 2024, Texas Tech Univ. (Oct. 16, 2024). In recent years, the Texas Legislature has shown a growing commitment to addressing produced water and supporting future technological developments in its treatment and reuse.

With all the innovation and new legislation, the Texas Supreme Court is also diving into the produced water conversation. This past March, a question of first impression was raised in *Cactus Water Services, LLC v. COG Operating, LLC*, No. 23-0676, 2025 Tex. LEXIS 591 (Tex. June 27, 2025). In *Cactus*, an oil and gas producer and a third-party water company were at odds over the ownership of the produced water. Under the law at the time of the conveyances at issue, COG Operating, LLC, the producer, was charged with proper handling and disposal of produced water. See *Cactus*, 2025 Tex. LEXIS 591, at 7. Cactus Water Services, LLC, the third-party water company, contended that once the hydrocarbons were separated, the remaining water mixture – or produced water – belonged to the surface owner. *See id.* at 2. The Texas Supreme Court ultimately held that under typical lease language conveying oil and gas rights, produced water is a part of the conveyance, even though not expressly addressed. Therefore, absent express language otherwise, produced water belongs to the operator, not the surface owner. *See id.* at 29.

III. Why should we care?

Produced water is increasingly at the center of both the courts and the Legislature, but why should we care? Texas is confronted with two emerging problems tied to produced water: (1) an escalating water crisis driven by persistent drought, and (2) the decreasing viability of traditional disposal methods. At the same time, advances in technology now allow for secondary recovery from produced water, enabling the extraction of valuable minerals and effectively turning trash into treasure. *See* Ewa Knapik, Grzegorz Rotko & Marta

Marszałek, *Recovery of Lithium from Oilfield Brines—Current Achievements and Future Perspectives: A Mini Review*, 16 Energies 6628 (2023). Further, alternative uses of produced water have piqued the interest of operators, offering the potential to generate additional revenue streams while simultaneously lowering disposal costs.

Drought and Water Crisis

Typically, water used in fracking is surface or groundwater. *See* Alejandra Martinez & Jayme Lozano Carver, *Texas Is Running Out of Water. Here's Why and What State Leaders Plan to Do About It.*, Tex. Tribune (Mar. 13, 2025). However, Texas is facing a water crisis. The Texas Water Development Board State Water Plan indicates Texas could face a 6.9 million acre-feet shortage of water by the year 2070. *See* Texas Produced Water Consortium, *supra* note 15 at 9. To put this in perspective, in 2022 Texas used 15.2 million acre-feet. *See* Historic Water Use Summary and Data Dashboard, Tex. Water Dev. Bd. If no water management strategy is put in place and Texas experiences another record high drought, approximately twenty-five percent of Texans could have less than half the municipal water supplies they need. *See* Texas Produced Water Consortium, *supra* note 15 at 10.

Texas' water shortage is even more pressing for West Texas and the Panhandle. About fifty-five percent of water used in Texas is sourced through aquifers, which are being stressed at record levels. *See* *Texas Water Tour*, Econ. Notes, Tex. Comptroller (2022). The Ogallala Aquifer, specifically, is one of the world's largest aquifers, supplying groundwater to eight states, including Oklahoma, New Mexico, and Texas. *See* *What Is the Ogallala Aquifer?*, Neb. Corn Bd.. In 2019, more than 4.4 million acre-feet were pumped from the Ogallala Aquifer, accounting for sixty-seven percent of water pumped from major aquifers. *See* *Texas Water Tour*, supra. Currently, we are drawing from this aquifer at 6.5 times its recharge rate. *See* Dylan Baddour, *To ease looming West Texas water shortage, oil companies have begun recycling fracking wastewater*, Tex. Tribune (Dec. 19, 2022). However, the current approach to the Ogallala Aquifer is one of "managed depletion." *See id*. Managed depletion is a strategy that involves deliberately using the aquifer until it is effectively exhausted. *See id*. While the Ogallala Aquifer is primarily used for irrigation, this intentional depletion is accelerating Texas' path toward a serious water shortage. *See Texas Water Tour, supra* note 25.

The Ogallala Aquifer isn't the only major water source in the Panhandle and West Texas. *See id*. The Pecos Valley and the Edwards-Trinity Plateau Aquifers supply most of West Texas. While mainly supplying water for irrigation, both aquifers could face the same issues plaguing the Ogallala Aquifer if something is not done. *See id*.

Dwindling Disposal Practicality

Drought conditions aren't the only water problem Texas currently faces. For decades, producers disposed of produced water via deep well injection. *See* Martha Pskowski & Dylan Baddour, *Companies aim to release more treated oilfield wastewater into rivers and streams*, Tex. Tribune (Apr. 29, 2024). Approximately 70% of produced water in the state of Texas is disposed of via deep well injection through saltwater disposal ("SWD") wells permitted by the RRC. *See* Texas Produced Water Consortium, supra, at 16; *see also* Produced Water Treatment Methods, Atlas Scientific (Nov. 8, 2024). Injection occurs several thousand feet below the groundwater table, where the water will, in theory, not encounter fresh water. *See* *What Is a Saltwater Disposal Well?*, Rogue Energy Servs. (July 25, 2022). The produced water is under extreme pressure when injected at deep depths, ultimately preventing waste migration through the subsurface rock formations and trapping the water until it evaporates. *See id*. Effective, disposal via injection comes with both monetary expenses and environmental concerns. *See* Texas Produced Water Consortium, *supra*, at 7; Market Snapshot: Produced Water Management, Dawnbreaker (Dec. 21, 2022) (estimating \$0.60–\$0.70 per barrel disposal vs. \$2.55–\$10 per barrel for treatment, with gap expected to narrow).

The link between seismic activity and produced water disposal wells has also caused the RRC to tighten restrictions on deep injection disposal. *See id.* In response, producers have shifted to injecting water into shallower rock. *See* *Permian Basin wastewater risks threaten oil output*, GlobalData via Yahoo!Finance (May 23, 2025). Water levels in this shallow rock have become so substantial, they risk breaching wells, swelling and rupturing the ground, and contaminating water sources. *See id*. The RRC has acknowledged this problem, and in May 2025 announced enhanced guidelines which went into effect June 1, 2025 for disposal wells in the Permian Basin. *See* *RRC Issues Enhanced Guidelines for Permian Basin Disposal Wells*, Tex. R.R. Comm'n (May 16, 2025). These guidelines place limits on the maximum water pressure and the maximum daily water injection volume, and require operators to assess old or unplugged wells to ensure that produced water does not escape through wellbores. *See id*.

With decreases in water availability and tightening of guidelines by the RRC on the disposal of produced water in both shallow and deep injection zones, something has to be done to address Texas' water woes.

Alternative Uses of Produced Water

In the Permian Basin alone, daily water production from horizontal wells is about 1,547 acre-feet. *See* Texas Produced Water Consortium, *supra*, at 8. By 2042, it is estimated to increase to 1,935 acre-feet. *See id*. The current practice is to dispose of this water, but new technology could breathe life into this waste. *See id*.

1. **Reuse for Enhanced Oil Recovery**

Enhanced oil recovery can occur via waterflooding. Waterflooding is a secondary recovery method that involves injecting water into a reservoir formation to displace residual oil. *See* *Waterflooding*, Soc'y of Petroleum Eng'rs (Jan. 29, 2025). Waterflooding is aimed at maintaining reservoir pressure while driving the oil towards production wells. *See id*. Waterflooding techniques extend a field's productive life, resulting in the recovery of 20% to 40% of the original oil in place. *See* Jie Cao et al., *Analysis of Waterflooding Oil Recovery Efficiency and Influencing Factors in the Tight Oil Reservoirs of Jilin Oilfield*, 13 Processes 1490 (2025). Produced water, instead of groundwater, can be injected into reservoirs as a secondary flood. *See* Basic Information About Water Reuse, U.S. EPA (updated Apr. 8, 2025). Utilizing produced water for secondary recovery methods, such as waterflooding, reduces the demand on freshwater resources and allows for preservation of groundwater for essential uses, recycling a costly byproduct of oil and gas production, and reducing overall disposal costs.

2. Reuse by Irrigation

Beneficial reuse of produced water is gaining traction as a strategy to address water scarcity and reduce reliance on freshwater resources. *See* Jamiya Barnett, *How Water Reuse Can Address Scarcity*, Envtl. & Energy Study Inst. (Dec. 17, 2024). Although still in the early stages of development, treated produced water has the potential to be used for irrigation. *See* Leslie Lee, *Can Treated Produced Water Safely Irrigate Crops?*, Tex. Water Res. Inst. (Aug. 1, 2025). In research funded by WaterBridge Operating, LLC, produced water will be treated in a three-step process by a water industry partner, using absorption, regeneration, and membranes. Preliminary studies found that produced water had minimal negative effects on plant development and even improved soil carbon levels, pH, and micronutrient availability, suggesting that crops such as cotton, alfalfa, and hay could potentially thrive under these circumstances. *See id.*

3. Reuse by Municipalities

Along with irrigation, produced water may be used for municipality purposes. While seemingly unconventional, these uses range from cement production to firefighting to dust suppression for roads and landfills. *See* Laura Slansky, *Four Steps to Quickly Evaluate Produced Water Reuse Option Viability*, Environmental Protection (June 1, 2019). Another potential use for treated produced water may be to "unleash" American energy by using the water for cooling of data centers that house vast numbers of servers which generate substantial heat. *See* Benoit Morenne, *The Oil Patch's 'Manhattan Project': How to Fix Its Gargantuan Water Problem*, The Wall Street Journal (April 21, 2025). Treating and reusing produced water transforms a costly waste disposal challenge into a valuable resource. By eliminating the need for large-scale disposal, a former burden may be turned into an asset with beneficial uses across agriculture, industry, and municipalities.

Along with the reuse of produced water, extraction of valuable minerals from the waste may also prove to be lucrative in coming years.

4. Extraction of Valuable Materials

As previously described, produced water is a mixture of fracking fluid, hypersaline brine, residual hydrocarbons, and other substances of varying concentrations. *See* Grzegorz Rotko, et. al., *Oilfield Brine as a Source of Water and Valuable Raw Materials—Proof of Concept on a Laboratory Scale*, MDPI (May 21, 2024). While produced water contains many minerals, lithium has stood out amongst the rest. Currently, the global lithium market sits around $24 Billion but is expected to rise anywhere from $55 to $75 Billion by 2030. *See* *Lithium Market Size, Share & Trends Analysis Report*, Grand View Research, (attributing growth to electric vehicles and energy-storage demand). With reports of high concentrations of lithium within Texas' produced water, Direct Lithium Extraction ("DLE") is an emerging method designed for lithium extraction. DLE is an extraction method that pulls lithium from produced water, like a magnet attracting only lithium ions, leaving most other minerals and water behind. *See* Amit Kumar et al., Lithium Recovery from Oil and Gas Produced Water: A Need for a Growing Energy Industry, *4 ACS Energy Lett.* 1637 (2019). This method is significantly more efficient than other traditional lithium extraction techniques, such as hard rock mining spodumene ore and solar evaporation, and offers a more favorable environmental impact. *See* *A Better Way: IBAT's DLE Technology vs. Traditional Extraction*, Int'l Battery Metals. As demand for lithium continues to surge, the efficient extraction of lithium from produced water positions DLE as a transformative solution.

V. Conclusion

Produced water – once dismissed as a burdensome byproduct of oil and gas operations – is now at the forefront of legal, environmental, and technological innovation in Texas. As Texas grapples with intensifying water scarcity and the diminishing feasibility of traditional disposal methods, produced water offers a promising, multi-faceted solution. Emerging technologies present an opportunity to reframe produced water not as waste, but as a resource. Moving forward, embracing innovation, regulatory clarity, and new practices will be critical in transforming Texas' water challenges into long-term opportunities.

Diversity & Inclusion Highlight

The Institute for Energy Law is proud to announce **Steptoe & Johnson PLLC** and **Yasser A. Madriz** of McGuireWoods LLP, as the recipients of its fourth Excellence in Diversity and Inclusion Award. Join us the evening of October 15, from 5:30-7:30 p.m. at The Asia Society Texas Center in Houston to honor this year's recipients – register online.

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A Message from IEL

Kimberly Phillips, General Counsel, Global Litigation at Shell USA, Inc., is the recipient of the 2025 Lifetime Achievement in Energy Litigation Award. The award presentation will take place at IEL's 24th Annual Energy Litigation Conference, November 4 at the Four Seasons Hotel Houston.

Check out the rest of our upcoming programs: the 2nd IEL Energy Project Development Conference, October 16 in Houston, TX; the 24th Annual Energy Litigation Conference, November 4 in Houston, TX *(early registration pricing ends October 22)*; the 9th Midstream Oil & Gas Law Conference, December 9 in Houston, TX *(early registration pricing ends November 20)*; the 14th ITA-IEL-ICC Joint Conference on International Energy Arbitration, January 22-23 in Houston, TX *(early registration pricing ends December 19)*; the 77th Annual Energy Law Conference, February 26-27 in Houston, TX *(this conference is FREE for IEL Advisory Board Members)*; and the 9th National Young Energy Professionals Conference, April 22-23 in Austin, TX.

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