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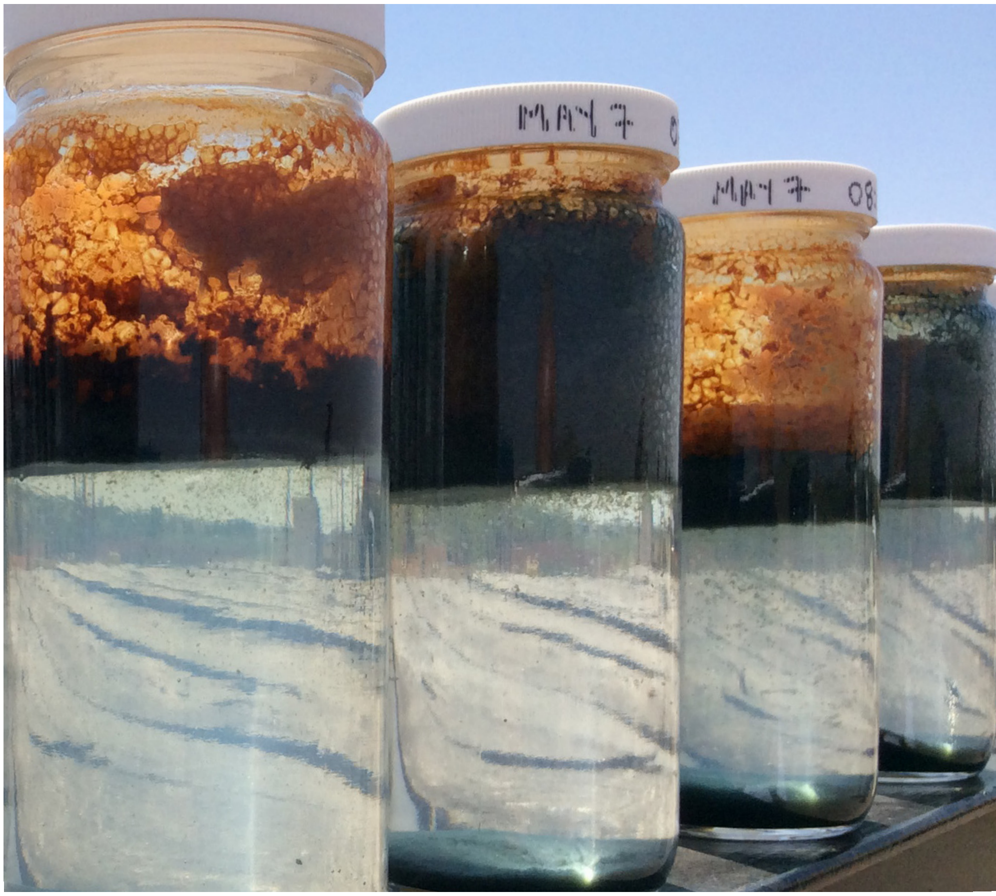

OILFIELD PRODUCED WATER OWNERSHIP IN TEXAS: BALANCING SURFACE OWNERS' RIGHTS AND MINERAL OWNERS' COMMERCIAL OBJECTIVES

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Executive Summary

- The surface estate owns produced water as a matter of law in Texas. However, if a producer transfers produced water to another party for the purpose of treating that wastewater for "subsequent beneficial use," the water becomes the property of the person who takes possession of it. (Chapter 122 of the Texas Natural Resources Code).
- A key flaw in the statute is that Chapter 122 does not address how, if at all, the producer would need to split revenues with the surface owner for a sale or a for-value transfer of produced water.
- Barring contractual arrangements to the contrary, a producer would likely only need to split those revenues from the sale of produced water remaining after subtracting treatment and handling costs necessary to make the water marketable.
- Strong policy and economic drivers support greater reuse of produced water.
- For instance, recycling larger volumes of produced water and integrating it with other non-potable supplies such as brackish water and municipal effluent would displace the use of potable fresh water for fracs, increasing local water security and extracting greater value from produced water that would otherwise have been injected into a deep disposal well.
- Recycling a larger proportion of produced water can also reduce—or ideally, preempt—problems with induced seismicity related to produced water disposal.
- Landowners who make money from freshwater sales and saltwater disposal well royalties may oppose greater produced-water recycling.

I. Background

Produced water has long been a fact of life in Texas' prolific oil and gas fields, with many wells producing as many as 10 barrels of water for each barrel of oil pumped.[1] Under long-established Texas law, the surface estate owner clearly owns produced water. But in economic terms, the ownership right has effectively lain dormant for decades. This is because produced water has thus far been treated largely as a waste product to be injected down a disposal well or reinjected in waterflood oil recovery projects, not as a commodity with potentially significant independent economic value.

The rise of water-intensive, industrial-scale shale development is upending this traditional produced-water management paradigm. On the water demand side, frac completions are becoming more water-intensive, with some Permian Basin completions now using enough

[1] Gabriel Collins, "Oilfield Water Recycling Could Significantly Boost Texas Water Supplies," Baker Energy Blog (Baker Hostetler, LLP), June 16, 2015, https://www.bakerenergyblog.com/2015/06/16/oilfield-water-recycling-could-significantly-boost-texas-water-supplies/.

volume to submerge a football field under more than 80 feet of water.[2] On the supply side, shale plays generally do not have large long-term water needs stemming from reinjection of water as part of an enhanced oil recovery program. This leads to localized buildups of "surplus" produced water both from initial flowback after new wells are frac'ed and as wells age and water cuts rise. Finally, multiple exploration and production (E&P) companies and numerous providers of dedicated oilfield water services are building water transport infrastructure that could significantly facilitate value-added physical transfers of water between parties.

As water intensity of frac completions increases, any meaningful increase in drilling activity will magnify local pressures on freshwater resources and intensify political and regulatory scrutiny of operators who use potable water for frac'ing, particularly in drought-prone areas. These factors will increasingly make produced water a more valuable—and potentially, tradable—source for frac'ing fluid in many areas. Texas thus has the opportunity to serve as a national leader in finding better ways to manage produced water across U.S. shale plays, an important objective given seismicity problems in Oklahoma and difficulties disposing of water in the Marcellus Shale.

If operators begin selling produced water (or otherwise transferring it for value) to one another or to midstream service providers, surface owners are likely to seek a share of the economic value realized.[3] As such, this brief seeks to accomplish five core objectives:

1. Discuss the economic, environmental, and policy benefits of broader produced-water reuse in the oilfield.
2. Clarify how the ownership of produced water is evolving in the Texas oilfield and show where existing laws contain gaps.
3. Outline the implications of creating a clear, tradable title to produced water in Texas.
4. Highlight potential legal obstacles to the development of produced water trading and briefly assess potential transaction structures for handling them.
5. Set forth key factors that would help accelerate the growth of produced water transactions in the Texas oilfield.

The overall spirit of the analysis is to help outline potential solutions that fully respect surface estate ownership of produced water, but recognize that overcomplicating produced water transactions would likely disincentivize industrial-scale produced water recycling and its attendant environmental, social, and economic benefits.

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[2] Data drawn from recent FracFocus disclosures of water use data from completions in southeast Reeves County.

[3] Here I highlight the work of attorneys Peter Hosey and Jesse Lotay, who provide an overview of the emerging legal challenges in "Quench My Thirst: Water Rights in the Context of Water Treatment Technologies," originally published in the Oil, Gas and Energy Resources Law Section Report, Winter 2013, and currently available on the Jackson and Walker website at https://www.jw.com/wp-content/uploads/2016/05/1836.pdf.

II. Trading Produced Water Would Benefit Both the Environment and U.S. Energy Security

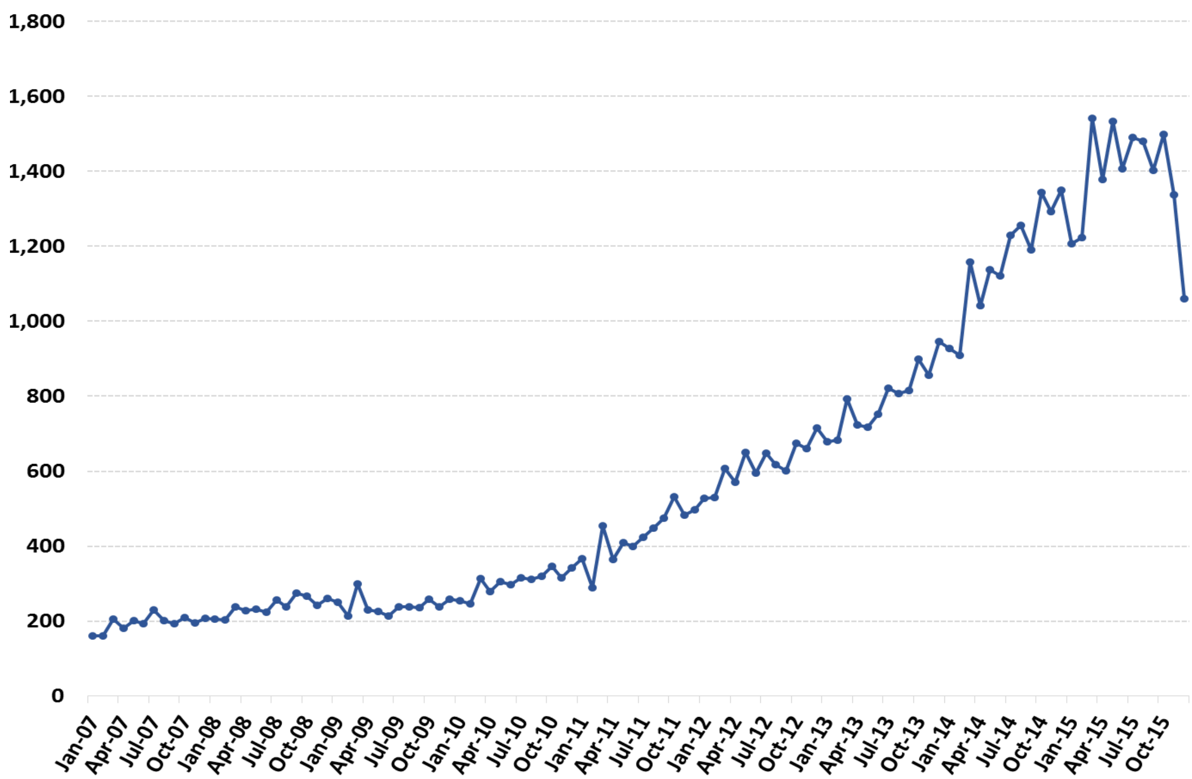
Three overarching factors make it important to clarify the finer legal details of produced water ownership in Texas.

First, the hydrological benefits of reusing larger quantities of produced water are often substantial. Although water demand for mining (the bulk of which is used for frac'ing) constituted only 1.25 percent of water use in Texas in 2014, nearly 37 percent of mining water consumption that year occurred in the top 10 oil-producing counties, according to data from the Texas Water Development Board. Much of that consumption was driven by frac'ing. In these counties, which all lie in the Eagle Ford and Permian Basin, mining water use accounted for an average of 40 percent of total water consumption, highlighting the material impact the shale boom exerts on local water conditions.

Against this backdrop, recycling larger volumes of produced water and integrating it with other non-potable supplies such as brackish water and municipal effluent would displace the use of potable freshwater for fracs, increasing local water security and extracting greater value from produced water that would otherwise have been injected into a deep disposal well. Using the displacement approach and keeping the water in oilfield use also avoids the high costs of treating produced water to a point that it could be repurposed for other uses such as agriculture.

Even with lower drilling activity levels by year-end 2015 (the last point at which complete data are available), Texas Railroad Commission data showed that the portions of the Texas Permian Basin with the most active drilling still had more than 1 million barrels per day (bpd) of fluids—i.e., produced water—being disposed of down commercial injection wells. A meaningful portion of this fluid stream could become tradable if economic, climate, and political factors nudge industry to begin viewing produced water as an independently valuable good, rather than simply a waste product.

Figure 1. Texas Permian Basin Commercial Fluid Disposal, Jan. 2011 to Dec. 2015 (Thousands of bpd from Texas RRC districts 08 and 7C)



Source: Texas Railroad Commission.

Second, turning produced water into a tradable commodity can help convert it from a substantial cost center into something that either actively generates revenue or is at least cost-neutral (depending on the share of realized economic value that surface owners are likely to claim). For even the most efficient shale operators, produced water management can still account for at least one-third of total lease operating costs. Thus, establishing a framework that promotes the sale, lower-cost offtake, or even cost-neutral transfer of produced water offers a way for E&Ps to significantly reduce lease operating costs and make U.S. oil production more globally competitive at a given price level.

Third, making produced water tradable can help catalyze more efficient capital investment in the necessary infrastructure. At present, numerous operators are spending significant sums of capital expenditure (CAPEX) dollars to build proprietary infrastructure in order to reduce their water management costs. Sector-wide, such an approach risks eventually creating substantial redundancy in water-handling capacity given that many of the operators in active basins like the Permian occupy adjacent acreage positions and could potentially share key infrastructure for mutual benefit.

Incentivizing broader trade in produced water would promote an approach that emphasizes building oilfield water infrastructure where it makes the most sense and with an eye to allowing third-party access, rather than forcing each producer to effectively seek produced water autonomy. Such a focusing effect could, all else being equal, promote more rational capital expenditures in the water-handling space, to the ultimate financial benefit of all operators in an area.

The common theme is that the core benefits enumerated above can only be fully realized if there is a framework of legal clarity that is sufficient to give operators and investors confidence that they can properly manage their risk/opportunity balance.

III. Produced Water Is Owned by the Surface Estate under Texas Law But Can Be Severed and Transferred by the Mineral Estate

Texas law clearly affirms that groundwater is a form of real property owned by the surface estate unless severed or otherwise reserved.[4] As such, the core question is whether the law also accords oilfield produced water the same status. A step-by-step analysis strongly suggests the answer is "yes."[5]

1. *Produced water pumped from a well qualifies as "groundwater" under Texas law.* The Texas Legislature defines groundwater as "water percolating below the surface of the earth."[6] Texas courts have long held that underground water capable of being obtained via a well is "percolating."[7] Produced water emanates from an underground formation and is obtained through a wellbore, thus strongly suggesting it meets the definition of "percolating" endorsed by the Texas Supreme Court.
2. *Groundwater is owned as real property in Texas.* The legislature "recognizes that a landowner owns the groundwater below the surface of the landowner's land as real property."[8]
3. *Texas law does not distinguish between groundwater types based on salinity or depth.* Neither the Texas courts nor the Texas Legislature make any ownership distinction based on the salinity or potability of groundwater under a tract of land. To boot, none of the signature Texas groundwater cases leading up to *Day*—a case line more than 110 years old—distinguishes between "fresh" water and more saline waters. The sole Texas Supreme Court case focused on water salinity as a potential determinant of groundwater ownership delivered a clear message: salinity bears "no consequence upon ownership."[9] Despite the fact that the water was produced from a converted oil well, the court determined that the water was "an incident of surface ownership

[4] *Edwards Aquifer Auth. v. Day*, 369 S.W.3d 814, 832 (Tex. 2012); *Tex. Water Code Ann*. § 36.002.
[5] This entire section draws heavily on Gabriel Collins, "The Brackish Water Estate in Texas," Texas Water Intelligence™, Water Note #1, June 6, 2016, https://texaswaterintelligence.com/2016/06/06/the-brackish-water-estate-in-texas/.
[6] *Water Code Ann*. § 36.001.
[7] *Texas Co. v. Burkett*, 117 Tex. 16, 29, 296 S.W. 273, 278 (1927).
[8] *Water Code Ann*. § 36.002 (West).
[9] *Robinson v. Robbins Petroleum Corp., Inc*., 501 S.W.2d 865, 867 (Tex. 1973).

> in the absence of specific conveyancing language to the contrary."[10] The court's decision in the *Robinson* case in essence determined that highly saline produced water from a deep layer (even an oil and gas-bearing one) was just another form of groundwater.

Energy producers and water recyclers worried that groundwater ownership in Texas might mean that produced water was not owned by a recycler and could not be resold to third parties unless the recycler also owned the surface estate.[11] The legislature responded with Chapter 122 of the Texas Natural Resources Code. Chapter 122 mandates that when a person takes possession of "fluid oil and gas waste" (in this case, produced water) to treat it for a "subsequent beneficial use," the produced water becomes that person's property and can be transferred to third parties for disposal or use in treated or untreated form.[12] Subsequent transfers of treated water or any other "treatment byproduct" by the initial recipient to a third party mean that the third-party recipient acquires clear title to the treated water.[13]

Chapter 122 significantly clarified produced-water ownership in Texas from the perspective of potential consumers who might receive such water from an E&P company. It also insulates water transferors from tort liability for injuries caused by releases of treated water post-transfer.[14] Yet despite Chapter 122's positive contributions, critical gaps remain, particularly with respect to potential revenue or value sharing between surface owners and E&P companies.

a. Chapter 122's key gaps concerning produced water transfers

Most importantly, Chapter 122 still does not address whether a producer who *sells* flowback or produced water or otherwise *transfers it for value* to a third party owes compensation to the surface owner. The statute gives the oil and gas producer authority to transfer title to produced water that it has custody of but does not legally own, yet it does not prescribe how, if at all, revenues should be allocated if the "transfer" occurs as a sale or other realization of value that accrues to the oil and gas producer's benefit.

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[10] *Ibid.*
[11] King, Phil et al. (Estes), HB 2767 Bill Analysis (Engrossed version), Senate Research Center, May 14, 2013, http://www.legis.state.tx.us/tlodocs/83R/analysis/html/HB02767E.HTM; Adam Friedman, "Recycling Flowback and Produced Water: Can Texas Do More to Throw Away Less?" State Bar of Texas, Oil and Gas Section, December 2, 2016, p. 77.
[12] Texas Natural Resources Code, Chapter 122.002, Subsection 1, http://www.statutes.legis.state.tx.us/Docs/NR/htm/NR.122.htm.
[13] Ibid., Subsection 2.
[14] This applies so long as the treated product is "generally considered in the oil and gas industry to be suitable for use in connection with the drilling for or production of oil or gas." See *Texas Natural Resources Code,* Chapter 122.003.

Figure 2. Chapter 122: Ambiguity related to Revenues from the Sale of Produced Water

	Legal Owner of the Produced Water			
	Surface Estate	Surface Estate	Title Transferred to Recipient	Subsequent Recipients
Scenario 1	Formation water comes to the surface along with E&P's hydrocarbon production	E&P separates water from the oil & gas stream	E&P pays third party to take the water away or gives the water away without charge	Subsequent transfers from third party to others
Scenario 2	Formation water comes to the surface along with E&P's hydrocarbon production	E&P separates water from the oil & gas stream	E&P sells water to a third party or otherwise transfers it for value*	Subsequent transfers from third party to others

*** Chapter 122 does not address how, if at all, the surface and mineral estates should allocate revenues realized from an initial sale of produced water by the mineral owner.**

In past cases involving statutory silence, the Texas Supreme Court has taken two fundamental approaches: (1) looking to the statute's purpose for guidance and (2) using the common law to fill gaps when a statute is silent regarding parties' rights and responsibilities.[15] House Bill 2767, which ultimately became Chapter 122 of the Texas Natural Resources Code, was intended to facilitate recycling and reuse of oil and gas wastewater (a.k.a. produced water). The pre-passage bill analysis offers no insights into whether the legislature contemplated revenue sharing for sales of produced water.[16] However, the statute's final adopted language—in particular, the sentence beginning "Unless otherwise expressly provided by a contract, bill of sale, or other legally binding document …"—does suggest legislators contemplated a range of structures for produced water transfers.

Specifically, that phrase suggests (1) that the legislature intended Chapter 122's language to provide the default legal basis for produced water transfers in Texas, and (2) that it contemplated the possibility of private parties using alternative contractual arrangements to govern commerce in produced water. The fact that the final statute remains silent on how revenues from a sale or other for-value transfer would be handled suggests that the matter is left for the transacting parties to contract between themselves—a sphere of action ultimately governed by the common law. In response to the omission of language governing sale or for-value transfers of produced water from the initial producer to subsequent owners, Section IV (below) offers a potential legal framework with which to analyze such situations.

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[15] *PPG Indus., Inc. v. JMB/Houston Centers Partners Ltd. P'ship*, 146 S.W.3d 79, 84-85 (Tex. 2004).
[16] Phil King et al., HB 2767 Bill Analysis (engrossed version), Senate Research Center, May 14, 2013, http://www.legis.state.tx.us/tlodocs/83R/analysis/html/HB02767E.HTM.

Chapter 122 also does not appear to protect a transferor of untreated oilfield wastewater from tort liability. Industry already handles this omission via contractual arrangements between parties. Consider the following examples, drawn from contracts between E&Ps and water gathering and disposal providers:

1. Subject to Producer's delivery of Produced Water that conforms to the specifications set forth on Exhibit D, attached hereto and made a part hereof, *at and after delivery by Producer to Gatherer of Produced Water at the Produced Water Receipt Points, Gatherer shall be deemed to be in exclusive control and custody thereof and shall be responsible for, and shall indemnify and hold harmless Producer and its Affiliates from and against, any claims relating to, or arising out of, any injury or damage caused thereby.*[17] (Environmental services provider's agreement with an E&P to provide produced water-gathering services in North Dakota)
2. [E&P] shall have responsibility for the Water upstream of each Custody Transfer Point including responsibility for any spills that occur upstream of a Custody Transfer Point. *Title to the Water delivered by [E&P] to [Service Provider] shall pass to [Service Provider] at each Custody Transfer Point. [Service Provider] shall have responsibility for the Water at and downstream of the Custody Transfer Point(s) including the responsibility for properly disposing of the Water and for any spills that occur at or downstream of a Custody Transfer Point...*[18] (Services provider's agreement with an E&P to provide produced water-gathering services in East Texas and Louisiana)

Furthermore, at least one midstream operator in West Texas explicitly highlights reduction of liability through title transfer as a fundamental reason for E&P companies to use its produced water-gathering and affiliated disposal services.[19]

Finally, Chapter 122 leaves significant issues concerning frac'ing fluid composition unresolved. These gaps touch heavily upon trade secrets, disclosure, and products liability laws that lie beyond the scope of this analysis but have been analyzed in-depth by other scholars.[20]

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[17] Gabriel Collins, "North Dakota Saltwater Disposal Enforcement Actions Highlight Key Legal and Social License Risks," Baker Energy Blog (Baker Hostetler, LLP), September 28, 2015, https://www.bakerenergyblog.com/2015/09/28/north-dakota-saltwater-disposal-enforcement-actions-highlight-key-legal-and-social-license-risks/.

[18] "Agreement for Firm Disposal of Salt Water between Charis Partners, LLC, and EXCO Production Company, LP," https://www.sec.gov/Archives/edgar/data/1403853/000119312510001971/dex1038.htm.

[19] Eclipse Midstream, LP, "About," http://www.eclipsemidstream.com/about/why-pipe/ (accessed February 6, 2017).

[20] See, for instance, Kirbie Watson, "The Emperor's New Clothes: Fracking Legislation in Texas," *LSU Journal of Energy Law and Resources* 3, no. 1 (2014), available at http://digitalcommons.law.lsu.edu/jelr/vol3/iss1/14.

IV. Produced Water Title Transfer: Economic Value Implications

Produced water ownership transfer is not simply a rehousing of legal liabilities and risks; it also opens the door to harnessing latent economic value. Once produced water has undergone a transfer of title that severs it from the original owner, that party no longer has any claim to the commodity, and it can be freely bought, sold, or otherwise transferred within the parameters allowed under the present regulatory regime.

Figure 3. Title and Liability Transfer Points for Oilfield Produced Water in Texas

	Produced Water Separated from Oil & Gas	Produced Water Sent to Proprietary SWD	Produced Water Trucked to Third-Party SWD	Produced Water Enters Commercial SWD Gathering Pipeline	Produced Water Enters Third-Party Purchaser/ Transferee's Pipeline
Legal Responsibility	E&P Operator	E&P Operator	E&P Operator	Pipeline Operator	Purchaser
Custody	E&P Operator	E&P Operator	Trucking Company	Pipeline Operator	Purchaser
Ownership	Surface Estate	Surface Estate	Surface Estate	Pipeline Operator	Purchaser

The locus of value is shifting away from an exclusive focus on the *service* of disposing of produced water to the economic value inherent in the *water itself*. In other words, rather than being viewed simply as a fluid to be sent down a pipeline to a saltwater disposal well (SWD) and disposed of, produced water (including flowback) will be transferred between parties for value.

Such "value" primarily manifests itself in two ways. The first is a direct sale of water from one party to another. The second potential mode of realizing value for produced water relies on avoiding costs. If produced water has resale value to a range of frac'ers in an area, E&Ps may be able to persuade a midstream provider to (1) take the water at no charge, treat it, and resell it, or (2) take water for a combination of disposal and/or treatment and resale, but do so at a reduced charge per barrel that accounts for the water's likely resale value.

If an E&P directly sells produced water in Texas, it may need to share sale proceeds with the surface estate owner. The way revenue sharing occurs will depend first on the contractual arrangements contained in the surface use agreement (SUA) governing the relationship between mineral and surface owner, and absent an SUA, would likely default to Texas common law criteria governing relations between the surface and mineral estates and payment of royalties.

a. The mineral estate likely does not need to compensate the surface estate for produced water unless it earns revenue net of costs from sale of the water.

Surface owners seeking compensation for produced water transferred to a third party but not sold for a net profit would likely fail. Under Texas law, the mineral estate owner has "the right to use as much of the surface as is reasonably necessary to extract and produce the minerals," otherwise broadly known as the "accommodation doctrine."[21] The accommodation doctrine primarily contemplates impairment of surface uses caused by actions of the mineral owner—for instance, placing pumpjacks in such a way that they block a farmer's center pivot sprinklers from functioning properly.[22]

The accommodation doctrine has not been applied to compensate surface owners for produced water that could have potentially been sold for a net revenue gain but was instead transferred without booking any revenue net of treatment and handling costs. The lack of precedent is unsurprising. E&Ps have no legal duty to market produced water, and surface owners can contractually seek compensation for physical impositions caused by water-handling operations—for instance, damage rentals made when water flowlines, recycling equipment, or other water-related infrastructure is installed.

For surface owners in Texas to successfully claim under the accommodation doctrine that as a general rule the mineral owner should compensate them for removing produced water from their land, they would have to demonstrate that:

1. The mineral lessee's use "completely precludes or substantially impairs" the existing use of the surface;
2. There is "no reasonable alternative method available to the surface owner" through which it can continue its existing use of the surface; and
3. There are "alternative reasonable, customary, and industry-accepted methods available to the [mineral] lessee" that will allow recovery of the minerals and also allow the surface owner to continue its existing use of the surface estate.[23]

These standards all focus on damage to the surface estate—not on the potential economic value of a byproduct produced along with oil and gas whose removal from the hydrocarbon-bearing formation does not create any perceptible changes to the actual surface of the overlying tract.

Produced water recycling or reuse generally does not substantially interfere with a surface owner's use of the parcel from under which the water originates, particularly if the actual treatment occurs off-tract. Indeed, in this scenario the water is simply transported off the tract into the treatment facility, which invokes the same general level of invasiveness as the "reasonable, customary, and industry-accepted" method that industry currently uses to resolve produced water issues: sending fluids by pipeline and/or truck to a deep injection

[21] *Merriman v. XTO Energy, Inc.*, 407 S.W.3d 244, 248-249 (Tex. 2013).
[22] Ibid.
[23] *Merriman,* 249.

well. And in such cases, surface owners can contract to receive damage payments and/or right-of-way rental fees.

To the best of this author's knowledge, surface estate owners in Texas have never been able to claim, by law, compensation for produced water disposed of in SWDs off their tracts, despite the potential for SWD operators to forego disposal and instead resell the water to other oilfield users. Furthermore, courts are also likely to recognize the public policy benefits of using recycled produced water to displace the use of freshwater in dry areas of Texas. Against that backdrop, so long as the mineral estate is not selling produced water for net positive revenues after deduction of reasonable costs in handling and marketing the water, a court would likely not be inclined to require E&Ps to share value-add transfer proceeds with the surface owner.

b. Any payment to the surface estate would likely only be made net of treatment and handling costs for the water.

Under Texas law, a *royalty* is generally defined as "the landowner's share of production, free of expenses of production."[24] Although it is not subject to the costs of production, a royalty is usually subject to post-production costs, including taxes, treatment costs to render the commodity marketable, and transportation costs."[25] Parties may agree to modify terms of the general rule.[26]

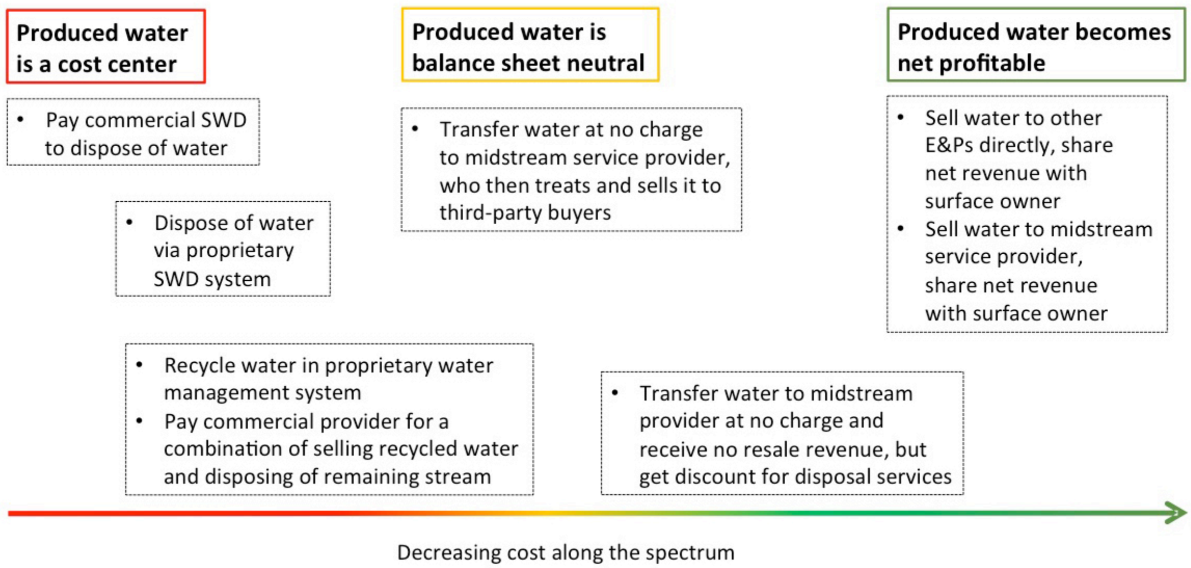
In practice, this means that the landowner and E&P would most likely split the net revenue left after pre-sale treatment costs and logistics charges that might be borne by the E&P. Either an outright sale or a takeaway transfer at reduced cost would reduce the E&P's water-related lease operating expenses. A cost-neutral transfer of produced water between E&Ps or other entities would also reduce water-handling cost burdens and benefit corporate balance sheets.

If the E&P disposes of the produced water generated on the lease by either of the methods described above or by other means that do not make the transfer of the produced water profitable to the E&P on a net basis, then the E&P transferring the water likely will not owe the surface owner payment for the water, since even a partially avoided cost is still ultimately a cost. Depending on the contractual arrangements between the mineral owner and surface owner, a reduction in operating costs could lead to higher payments to royalty owners (if said royalty clauses award royalties based on a price net of post-production costs, since water handling often accounts for a significant portion of total lease operating expenses).

If the landowner refused to bear a reasonable share of post-production costs needed to make the water saleable, then the E&P would most likely simply revert to existing practices, either reusing the water for its own operations on the lease or sending it off for disposal via injection well.

[24] *Heritage Res., Inc. v. NationsBank,* 939 S.W.2d 118, 121–122 (Tex. 1996).
[25] *Heritage Res. Inc. v. NationsBank*, 939 S.W.2d 118 (Tex. 1996); Chesapeake Exploration, L.L.C. v. Hyder, No. 14-0302 (Tex. Jan. 29, 2016).
[26] *Heritage Res., Inc. v. NationsBank,* 939 S.W.2d 118, 121–122 (Tex. 1996).

Figure 4. Potential Transaction Structures for Produced Water in Texas



V. Potential Friction Points

In some areas—such as parts of the Permian Basin where frac water supplies are not easily available—surface owners often earn significant sums selling fresh water to the oilfield. In such cases, landowners (typically farmers and ranchers) would likely oppose significant growth in produced-water recycling that did not yield revenues to the surface owner. The reason is simple: freshwater sales to energy operators yield much higher rents than do farming or ranching. Supplying 200,000 bbl of fresh water to an E&P can currently earn a rancher more than $100,000 in revenue at a high profit margin in drier parts of the Delaware Basin. To earn the same amount of profit would require him or her to sell hundreds of feeder cattle.[27] For surface owners in this position, greater use of produced water that displaces potential freshwater sales would be a distinct threat to the profitability of their land and ranching operations.

[27] See *USDA Weekly Livestock, Poultry & Grain Market Highlights*, 30 January 2017, "Cattle and Beef," CME Feeder Cattle Index price of $131.20 per 100-pound weight, assuming wean weight for calves of 600 pounds. https://www.ams.usda.gov/mnreports/lswlpgmrkthighlight.pdf

VI. Conclusion

If WTI crude oil prices can sustain in the $55 to $65/bbl range, drilling and completions activity in the core Texas oil and gas plays is likely to rise significantly from current levels. More demand for frac water and more flowback water coming from new wells would help set the stage for both sales and cost-neutral trades of produced water. The Permian Basin's higher activity level and leading position on the water infrastructure development curve suggest it will be the first basin where produced water becomes a value-added commodity in its own right. Locally sourced produced water will likely become part of a larger "unconventional water" stream that helps drillers reduce freshwater use in water-poor but oil- and gas-rich areas.

The legal environment is increasingly favorable for trades of produced water between operators and midstream providers. The protections from tort liability provided by Chapter 122 of the Texas Natural Resources Code for parties transferring treated produced water to others for oilfield reuse mark a major breakthrough. Texas law strongly protects parties' freedom to contract, which will generally put existing agreements for custodial and title transfer of produced water from E&Ps to midstream disposal and recycling providers (or other E&Ps) on robust legal footing.[28] Private contractual agreements for produced water title transfer would also likely enjoy significant public policy support, since reusing produced water can help reduce the oilfield's fresh water use, conserve scarce freshwater resources, and reduce potential risks of induced seismic activity caused by deep injection disposal.

As drilling activity begins to ramp back up, produced water trading and reuse are likely to grow incrementally, occurring first in high-activity areas where fresh water is scarce. A combination of higher oil prices and drought—a highly probable event in Texas—could significantly boost trade in produced water between E&Ps and third-party midstream service providers.

[28] See, for instance, *Phila. Indem. Ins. Co. v. White*, 490 S.W.3d 468, 489 (Tex. 2016) and *In re Prudential Ins. Co. of Am.*, 148 S.W.3d 124, 129 (Tex.2004): "As a general rule, parties in Texas may contract as they wish so long as the agreement reached does not violate positive law or offend public policy."