ROYALTY OBLIGATIONS IN TEXAS RELATING TO PRODUCTION OF INJECTED CARBON DIOXIDE

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I. INTRODUCTION

The Texas oil and gas industry has undergone significant changes over the years. From the time of the first discoveries in Corsicana and southeast Texas near the turn of the twentieth century to the incredibly complex fracturing techniques used to exploit the Barnett shale, the constant factor in the Texas oil and gas industry has been change.[2] But the industry itself, especially the methods of exploration, are not the only

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2. *See generally* J. LINSLEY, E. RIENSTRA & J. STILES, GIANT UNDER THE HILL: A HISTORY OF THE SPINDLETOP OIL DISCOVERY (Texas State Historical Ass'n 2002) (discussing the early Texas oilfield); D. LOHOEFER, J. ATHANS & R. SEALE, NEW BARNETT SHALE HORIZONTAL COMPLETION LOWERS COST AND IMPROVES EFFICIENCY, SPE paper 103046 (Society of Petroleum Engineers 2006) *available at* http://www.spe.org/atce/2006/technical/documents/spe1030461.pdf.

things that have changed. Over time, the common law and the statutory law relating to oil and gas have been transformed. Just as the industry developed new and unique responses to the initial problems encountered at Spindletop,[3] the law has had to respond to this change and develop a body of thought and procedure relating to new facets of the industry.[4] For example, little discussion had occurred in the common law regarding the effect of simultaneous production from multiple zones from multiple wells in the same field until the technology to accomplish this feat became more feasible in the 1990's.[5] There is no doubt that new and complex industry developments will mandate newer standards and areas within the common law.

Since the 1970's, more and more operators in Texas have elected to engage in tertiary recovery operations for their aged oil fields. One of the most common forms of tertiary recovery involves the injection of carbon dioxide into the existing reservoir. This process, more fully described below, acts to lighten the remaining oil reserves and, if successful, can act to extend the life of a reservoir by decades, greatly enhancing the amount of reserves that can be recovered.[6]

But all is not that easy and simple. Once the operator has injected the carbon dioxide into the ground, it becomes part of the gas stream recovered during the oil production. As a component of the gas stream recovered during production, some argue that royalties are due on the same carbon dioxide that the operator intentionally injected into the ground. Others argue that the presence of carbon dioxide in the gas stream, and the resulting effect on the value of that gas stream, creates a cause of action in favor of the royalty owners. Until now, the courts in Texas seldom have been called upon to decide issues relating to the presence of purposely-injected carbon dioxide in gas produced along with oil.[7] This dearth of case law, however, is coming to an end. In several situations around the state, lawsuits have been filed demanding damages for "missing" royalty payments for carbon dioxide produced in the gas

3. *See* LINSLEY ET AL., *supra* note 1, at 98-99 (discussing the advent of drilling mud at Spindletop).

4. *E.g.*, Seagull Energy E & P, Inc. v. R.R. Comm'n of Texas, 99 S.W.3d 232, 237 (Tex. App.—Austin 2003, pet. denied) (deciding a case of first impression on production of commingled gas from multiple wells).

5. *Id.* at 235.

6. The United States Department of Energy notes that typical initial production methods may bring only ten percent of the reserves in place to the surface, while enhanced methods like carbon dioxide injection promise to raise the amount of ultimate recovery to between thirty to sixty percent of the original reserves in place. *See* U.S. Department of Energy, Enhanced Oil Recovery/CO2 Injection, www.fossil.energy.gov/programs/oilgas/eor/index.html (last visited April 14, 2007).

7. *See generally* KUNTZ, LAW OF OIL AND GAS § 24.1 (1962).

stream or, at the least, damages stemming from the negative effect of the presence of carbon dioxide in the gas stream.

In light of this absence of common law on the subject, this article is designed to discuss and suggest appropriate bases and rationales for the analysis of royalty obligations, if any, as they might relate to injected carbon dioxide. Part II of this article will discuss the physical properties involved in the injection of carbon dioxide into a producing formation and the attributes of the production streams thereafter. Part III will discuss the nature of the carbon dioxide produced within the gas stream, whether it retains its personal property nature or whether it somehow transformed into real property when injected. Part IV will discuss the effect of the presence of carbon dioxide on the value of the gas stream and whether a royalty owner might have a claim for damages against the operator relating thereto. Part V will discuss the legal significance of and the availability of judicial redress by a royalty owner for the encroachment of carbon dioxide from injection operations on one property onto another. Finally, Part VI will address whether the discovery rule might apply to lawsuits involving claims for non-native carbon dioxide production.

II. THE BASIC MECHANICS OF OIL PRODUCTION, THE INJECTION OF CARBON DIOXIDE, AND ROYALTIES

A. Basic Mechanics

Texas is rife with sizeable, aged fields whose primary product is oil. Although many of these reservoirs are among the historically most prolific of the world's reservoirs, most of them have been in decline for many years.[8] This decline is the natural by-product of the removal of the hydrocarbons originally existing in the strata below. Since the earliest days, engineers have struggled to improvise ways of enhancing and extending the life of these reservoirs.[9]

Before discussing the enhanced oil recovery activities commonly used in the field, an explanation of certain aspects of oil production is necessary. Oil is found in strata of rock under the ground at varying levels and pressures. When a well is drilled, the oil and other fluids in a

8. For example, some fields in the Permian Basin began declining in production in the 1950's. Texas achieved record production in 1972 with 1,263,412,000 barrels, which number has declined ever since.

9. Many experts have gauged that oil recovery operations, without advanced techniques, recover only 10 to 20% of the oil in place in a typical pressure-driven reservoir. *See* Enhanced Oil Recovery, *supra* note 6. Often this paltry percentage of recovery results from the characteristics of the oil itself—it literally sticks to the rock in which it is found.

penetrated formation move toward the new area of low pressure just created (the wellbore). The oil then flows up the wellbore and is "produced" at the surface. As the oil rises, its ambient pressure drops, until at the surface it is subject only to atmospheric pressure. When the oil reaches the surface, this drop in pressure causes a release of gas that was held within the oil when it was under pressure—a concept similar to the carbonation in a bottle of soda. This gas is known as casinghead gas (as that is the approximate location in the production process where it was released from entrainment in the oil).[10] This casinghead gas, a by-product of oil production, is captured also and used, sold, or reinjected as a part of the operations on the property.

It is important to note that the volume of casinghead gas produced bears a strong proportional relationship to the volume of oil produced. Moreover, one of the more valuable aspects of casinghead gas production is the fact that it carries with it a high percentage of "heavy" or "wet" hydrocarbons.[11] These heavy hydrocarbons are removed from the casinghead gas stream at a liquids or "gasoline" recovery plant designed to separate the valuable heavier hydrocarbons from the remaining methane, or "dry" gas. In most wells, the "residue" methane gas contains some small percentage of naturally occurring carbon dioxide. So long as its percentage of the total gas volume does not exceed particular levels, it is accepted as part of the residue gas stream for sale and transport in interstate pipelines.[12] Once separated, the heavier hydrocarbons (in liquid form) and the dry gas stream are sold at the plant's "tailgate."

In the 1950's through the 1970's (and beyond), many Texas operators began unitizing large areas in producing fields in order to allow them to coordinate operations that would enhance the life of the field, activities that would not make sense on just a few particular leases. Once the fields were unitized, some of these operators instituted secondary recovery operations. Often the operators would inject vast volumes of water into select wells in the units in order to drive some of the remaining hydrocarbons toward wells that were still producing.[13] An understood

10. Casinghead gas is also referred to as dissolved gas or associated gas, as it is the natural gas that, underground, is dissolved into the oil and is associated with the production of oil.

11. The dry (residue) gas stream is comprised mainly of methane, while casinghead gas is rich in ethane, propane and the other more complex hydrocarbons.

12. Most dry gas is valued on the basis of its heating value (measured in British Thermal Units, or "BTU") per unit of volume. Because carbon dioxide does not burn, it does not add to the BTU content of the gas stream. Most purchasers and transporters (pipelines), however, set maximum levels of carbon dioxide for gas they will accept. If the level is exceeded, the pipeline reserves the right to reject the gas.

13. Properly operated waterfloods should recover an additional 15% to 20% of the original oil in place. Maverick Energy, Inc., Fundamentals of Finding Oil: Secondary Recovery (2002), http://www.maverickenergy.com/oilgas.htm (last visited April 14, 2007); *See also* R.R. Comm'n v. Manziel, 361 S.W.2d 560, 568 n.5 (Tex. 1962) (observing that as of January 1, 1958, over 2.3

offshoot of this "secondary recovery" program was the vast increase in the production of water from the wells. These waterfloods usually caused a reversal in the production decline in these fields. This reversal, unfortunately, was temporary—after the waterflood had been in full progress for some time, the quantities of hydrocarbons produced once again began to decline.

B. Injection of Carbon Dioxide

Recognizing this decline, engineers devised newer, tertiary programs for increasing the percentage of recoverable reserves. These tertiary (or third stage) programs can take many forms, including carbon dioxide injection.[14] In 1972, one of the first carbon dioxide injection programs was initiated in the Permian Basin in Scurry County, Texas. In a carbon dioxide injection program, somewhat "pure" carbon dioxide is injected into select wells in a field or unit. This carbon dioxide often does not behave like water when it is injected into an oil-bearing strata. Rather than acting as a "wall" pushing the oil toward the producing wells, the carbon dioxide dissolves into the oil—rather a reversal of the earlier discussion of the release of casinghead gas. You might think of carbon dioxide injection as the fizz injected into a soda bottle, where it will stay until released by the "well," i.e., when the bottle is opened. When a gas like carbon dioxide can dissolve or blend into another fluid medium, it is said to be "miscible."[15] Once dissolved into the oil, the "light" carbon dioxide not only raises the formation pressure, but it also lowers the viscosity of the oil and makes it flow more easily.[16]

When the MEOR operations are planned, a substantial process is involved. The State of Texas has numerous rules and regulations in place to govern oil and gas operations, including plans and programs for enhanced recovery. Statewide Rule 50 regulates enhanced oil recovery operations, including carbon dioxide injection plans.[17] Before an operator can commence a carbon dioxide tertiary recovery operation, it must present its plan to the Railroad Commission. The Commission will analyze the plan for efficacy. In addition, the proposed operator of the injection program must notify the surface owner, nearby operators, and

billion barrels of salt water had been injected into the Woodbine sand in East Texas).

14. Other types of tertiary enhanced oil recovery systems are alkali waterfloods, carbon dioxide augmented waterflooding, cyclic steam injection, and immiscible carbon dioxide displacement. *See* 16 TEX. ADMIN. CODE § 3.50 (2007) (Enhanced Oil Recovery Projects).

15. That is why carbon dioxide injection operations are often referred to as MEOR—Miscible Enhanced Oil Recovery.

16. Often, MEOR activities are carried out in conjunction with waterflood operations.

17. 16 TEX. ADMIN. CODE ANN. § 3.50(c)(19)(B) & (G) (2007) (Enhanced Oil Recovery Projects).

other affected persons. On top of that, the operator must publish its notice of application in the local newspaper having general circulation in the county where the operations are to take place.[18]

Once approved, the preparation for the MEOR activities begins. Miles of new pipelines (for supply and removal) might be laid. In some situations, an operator or group of operators will construct a plant designed to remove the carbon dioxide from the casinghead gas stream. As the MEOR operation begins, the carbon dioxide enters the producing formation and dissolves into the fluids present therein. As the area affected by the carbon dioxide expands, the fluids infused with the injected carbon dioxide eventually reach the wellbores of the producing wells in the field. At this time, the casinghead gas stream begins to reflect a higher percentage of carbon dioxide.[19] This carbon dioxide percentage can rise to over ninety percent of the dry phase of the casinghead gas as the injection operations mature.

As the casinghead gas becomes more and more infused with carbon dioxide, it can no longer be treated at typical liquid recovery gas plants. At that time, these streams must be processed initially in a carbon dioxide recovery plant, which will drop or squeeze some of the heavier hydrocarbons for sale or use and remove most of the carbon dioxide from the gas stream. The "recovered" carbon dioxide is recycled and sent back to its owner for reinjection into the field. The remaining gas stream is then sent to the standard liquids recovery plant, which separates the liquids as noted above.

C. Royalties

As most reading this article are aware, royalties differ depending on the type of production. In a typical oil and gas lease in Texas, the lessor is entitled to a stated fraction or percentage of the oil produced. The lessor is usually entitled to take this share in kind or to have the operator market the oil on its behalf.

Royalties on gas production are handled differently. First, the royalty owner usually does not have the right to take gas in kind—it is entitled to only a payment. Second, gas royalties are typically defined under a bifurcated royalty clause: royalty on gas sold at the well (or on the lease) is measured based on the proceeds received from the sale of the gas, while royalty for gas sold or used off the lease is measured by its market

18. *Id.*

19. Interestingly, the BTU content of the overall contaminated casinghead gas stream does not drop very much because of the BTU-rich heavier hydrocarbons transported by the carbon dioxide. If the liquids were removed and the carbon dioxide left in, however, the BTU value of the gas would plummet.

value.[20] As a matter of course, casinghead gas usually is computed under the proceeds clause because of the way it is sold.

Because casinghead gas usually must be processed before it can be transported and marketed to downstream users, operators often sell their casinghead gas at the wellhead to a local gas recovery or processing plant. These sales contracts, commonly referred to as casinghead gas contracts or gas purchase agreements, almost always provide for the sale to occur at the wellhead, thus invoking the proceeds section of a bifurcated royalty clause.[21] These contracts also vary in the manner in which they provide for the plant to compensate the selling operator. Many, if not all, of the historic casinghead gas contracts call for the plant to take the gas, process it, sell the resulting products, then remit to the operator a percentage of the proceeds realized, with the plant keeping a percentage to cover its operations and, hopefully, provide a profit. Some later gas processing agreements, however, provide that the operator retains title to the gas, and the resulting products from the gas, but will pay the plant operator a processing fee. In any case, once these proceeds are paid to the operator (or the operator sells the gas if it retained title thereto), the operator now has the proceeds that form the basis by which it can determine the royalty owed.

When a casinghead gas stream contains high levels of carbon dioxide,[22] the gas recovery or processing facility usually will cut a harsher deal. The plant will pay the operator a smaller percentage of the proceeds (or charge a higher processing fee) because the casinghead gas contaminated with carbon dioxide first must be processed at a carbon dioxide removal facility (not an inexpensive proposition) before the gas is sent to the standard liquids removal facility. As a result of this harsher deal, the royalty owner directly feels the pain when its royalties are directly proportional to the amount of the proceeds that the plant pays the operator. Because of this, some royalty owners have begun to seek redress for this diminution—whether through claiming that the royalty obligation attaches to the carbon dioxide itself or by trying to recover for the reduction in the value of the casinghead gas stream caused by the presence of the carbon dioxide through some other theory.[23]

20. *See,* e.g., Yzaguirre v. KCS Resources, Inc., 53 S.W.3d 368, 372 (Tex. 2001) (discussing these clauses in the context of the thorny issues raised when determining royalty differences depending on which royalty clause applies).

21. Gas processing agreements, on the other hand, may not call for the transfer of title in the gas at all; rather, they often contain just a fee-based agreement for the services provided by the plant.

22. Such as after the onset of MEOR operations.

23. Remember that, as noted above, most casinghead gas streams contain some naturally occurring carbon dioxide. Because this natural, original carbon dioxide often does not rise to the point at which the gas stream needs additional treatment for its removal before processing and

III. IS INJECTED CARBON DIOXIDE SUBJECT TO ROYALTIES ONCE PRODUCED?

The operator of a carbon-dioxide-based MEOR operation typically buys carbon dioxide from a vendor. The Bravo Dome field located in northeastern New Mexico[24] and the McElmo Dome field located in southwestern Colorado are the source of most carbon dioxide used in carbon dioxide injection programs in the Permian Basin region of west Texas and eastern New Mexico. Harding County estimated that carbon dioxide sales in calendar year 2002 amounted to almost $61 million. With this level of investment, it is unsurprising that an MEOR operator wants to maximize use of its gas purchase. Stated another way, the operator does not want to pay more money for gas that it already paid for. Owners of a royalty interest on the production from a lease or unit may take a different view and argue that they are owed a royalty on carbon dioxide produced during MEOR operations. Operator, meet the rule of capture.

Texas law concerning ownership of oil and gas is long-established—the landowner holds title to oil and gas in place because it is considered to be a part of the realty.[25] This ownership concept is constrained (1) by the rule of capture—oil and gas produced from your well belongs to you—and (2) by state regulation—in Texas, the Railroad Commission. Put into the usual circumstance of exploration and production under a lease of the mineral interest, the lease operator owns produced oil and gas upon reaching the surface as personalty, subject to any royalty obligations owed to the lessor of the mineral interest. Depending on the terms of the lease, the royalty owed on gas may be based on either the market value at the wellhead of the produced gas, or the amount realized from the sale of the gas.[26] The argument advanced by royalty owners is that the operator owes the same duties with respect to carbon dioxide as it does to the hydrocarbon portion of the produced gas stream. This argument turns

sale, in essence the royalty owner is paid royalties for the naturally occurring carbon dioxide in the casinghead gas stream. The new litigation stems from claims to a share of or resulting from the presence of the new, injected carbon dioxide.

24. The Bravo Dome CO2 field lies within Harding, Union and Quay counties. *See* Harding County, New Mexico Natural Resources web page, http://www.hardingcounty.org/natural_resources.htm (last visited April 14, 2007). The estimate of carbon dioxide reserves in the field exceeds than sixteen trillion cubic feet. *Id*.

25. Elliff v. Texon Drilling Co., 210 S.W.2d 558, 561 (Tex. 1948); *See also* Lemar v. Garner, 121 Tex. 502, 50 S.W.2d 769 (1932); Humphreys-Mexia Co. v. Gammon, 113 Tex. 247, 254 S.W. 296 (1923); Waggoner Estate v. Sigler Oil Co., 19 S.W.2d 27 (Tex. 1929); Texas Co. v. Daugherty, 176 S.W. 717 (Tex. 1915). The ownership interest is characterized by the Supreme Court as "absolute title in severalty to the oil and gas in place on [the] land." *Elliff*, 210 S.W.2d at 561.

26. *See supra* Part I.

entirely on the status of the produced carbon dioxide—in other words, whose gas is it?

The genesis of the rule of capture was the notion that oil and gas, like game animals, run wild and free and are owned by no one until taken or captured.[27] A wild animal that is captured is owned, but once released it regains its status as wild and free, subject to capture by another. Royalty owners argue that the same is true for carbon dioxide. After all, carbon dioxide occurs naturally in underground formations.[28] Shouldn't the operator treat production to the surface of naturally occurring substances the same? The presence of carbon dioxide in the casinghead gas stream is a natural consequence of the production of hydrocarbons from underground formations.[29] From the royalty owner's perspective, the operator's injection of carbon dioxide into underground formations is simply a release into the wild, with no guarantee of recapture. Thus, when the carbon dioxide is recaptured by production as part of the casinghead gas stream, the operator owes a royalty on the carbon dioxide along with the natural gas and liquids. The operators' response—royalty owner, meet *Murchison*.[30]

In 1962, the Dallas Court of Civil Appeals issued an opinion that drew a distinction between natural gas in its natural state and "extraneous gas."[31] The allegations in the *Murchison* case are straightforward.[32] Lone Star acquired all of the wells in a depleted gas field and entered into a unit operating agreement with the owners of the leases and the land to use the field formations for injecting and storing extraneous gas.[33] After Lone Star began injecting, storing and withdrawing gas from the field, Murchison and Sanders, the soon-to-be defendants, drilled a well on land adjacent to the lands comprising the unit operated by Lone Star and

27. *See* Lone Star Gas Co. v. Murchison, 353 S.W.2d 870, 877-80 (Tex.Civ.App.—Dallas 1962, writ ref'd n.r.e.) (and cases cited therein).

28. The Bravo Dome and McElmo Dome fields are two prime examples. *See* New Mexico Bureau of Geology and Mineral Resources, Natural Accumulations of Carbon Dioxide in New Mexico and adjacent parts of Colorado and Arizona, http://geoinfo.nmt.edu/staff/broadhead/CO2.html) (last visited Apr. 14, 2007) (listing commercial accumulations and potential uses of carbon dioxide).

29. See Part I, *supra.*

30. Note also that Professor Kuntz advances a separate theory: that injected gas of any type is more like a supply used by the lessee to promote production, so it retains its personality nature. KUNTZ, LAW OF OIL AND GAS § 42.7 (1962)

31. *Murchison*, 353 S.W.2d at 875. The *Murchison* court defined extraneous gas to mean "gas which has been produced elsewhere, acquired and owned by [the operator] and then for the purposes of storage, injected into [a] storage reservoir . . . pursuant to authority of the Railroad Commission of Texas." *Id.*

32. Instead of a recitation of facts, the opinion quotes the substance of Lone Star's trial court petition. *Id.* at 871-75.

33. *Id.* at 872.

began producing gas, including gas injected by Lone Star.[34] Lone Star filed suit against Murchison and Sanders, seeking damages for the value of Lone Star's gas taken by the defendants and an injunction against any further takings.[35] Murchison and Sanders responded with special exceptions to Lone Star's petition on the grounds that Lone Star lost title to the extraneous gas when it injected the gas into the underground formation.[36] The trial court granted the special exceptions and dismissed Lone Star's claims.[37] The court of appeals reversed because "the trial court erred in applying the rule of original capture to a situation as presented here."[38]

The court of appeals reached that conclusion after examining and rejecting a line of cases from other states holding reinjection of gas into subsurface formations restored the gas to its former wild and natural status.[39] The gas purchased by Lone Star, transported through a pipeline and injected through wells into the formation underlying Lone Star's unit, belonged to Lone Star, even if the gas migrated beyond the geographic limits of Lone Star's unit.[40]

The royalty owner's response—in *Lone Star*, all gas production from the formation ended before Lone Star reinjected gas. Clearly, the Murchison and Sanders well produced gas reinjected by Lone Star into

34. *Id*. at 872-73. Murchison and Sanders actually drilled their well to a depth greater than the depth of the formation used by Lone Star and completed the well in a lower formation. *Id.* at 873. Murchison and Sanders then perforated the well casing to take gas from Lone Star's formation. *Id*.

35. *Id*. at 871.

36. *Id*.

37. *Id*. The trial court's judgment held that Lone Star lost title to gas injected into the storage formation when the gas migrated under the land on which Murchison and Sanders held their lease and was then produced from the defendants' well. *Id*. at 874.

38. *Id*. at 880.

39. *Id*. at 875-76. The genesis of the "returned to the wild" status for reinjected gas (mineral *ferae naturae*) is *Hammonds v. Cent. Kentucky Natural Gas Co.*, 75 S.W. 204 (Ky. Ct. App. 1934). The *Murchison* court cited *Hammonds*, another Kentucky court of appeals case, a Pennsylvania case and an Oklahoma case as the primary sources of the mineral *ferae naturae* doctrine. *Murchison*, 353 S.W.2d at 875-76. The Dallas court of appeals then cited a number of authorities who strongly disagreed with the analogy between subsurface hydrocarbons and surface-dwelling wild animals. *Id*. at 876-77 (citing a treatise, law review articles from Kansas, Massachusetts, Texas, Virginia, and West Virginia, and an American Bar Association publication). The *Murchison* opinion then observed that some 26 years after *Hammonds*, a court finally got around to analyzing and rejecting the Kentucky court's conclusions about ownership of reinjected gas. *Id*. at 877-78 (citing White v. New York State Natural Gas Corp., 190 F. Supp. 342 (W.D. Pa. 1960)).

40. *See Murchison*, 353 S.W.2d at 879. Murchison and Sanders challenged the jurisdiction of the trial court to hear Lone Star's claims, contending that the suit was a collateral attack on the Texas Railroad Commission's approval of Murchison and Sanders' application to complete their well in the formation containing Lone Star's gas. *Id*. at 880. The *Murchison*court concluded that while the Railroad Commission had the power to authorize Murchison and Sanders to complete their well in Lone Star's formation, the Commission had no authority to determine who owned the gas produced from that zone. *Id*. at 881-82.

the formation. It's different if the field formation is still producing gas. The operator's reply—let's talk about *West*.

In *Humble Oil & Refining Co. v. West*,[41] the dispute involved a gas field included within lands sold by members of the West family to Humble.[42] In 1970, the Railroad Commission authorized Humble to use the subsurface reservoir for storage of natural gas.[43] One basis offered by Humble for the injection program was to preserve the storage capabilities of the producing formation by preventing saltwater encroachment.[44] Two months later, the Wests sued Humble, contending that Humble could not use the Clear Lake field for gas storage before production of all native gas or, in the alternative, that Humble owed a royalty on all gas produced from the reservoir, whether native or stored.[45] The trial court denied the Wests' request for an injunction but entered a decree that Humble owed a royalty on all gas produced from the field, including storage gas.[46] The court of appeals reversed the trial court and ordered entry of an injunction barring Humble from using the formation for storage until production of all native gas occurred.[47] The Texas Supreme Court disagreed with both the trial court and the court of appeals.

The Supreme Court considered and reversed the grant of injunctive relief, based on two factors. First, production of all native gas would result in the encroachment of water throughout the producing formation, with the result that gas could not be injected and stored.[48] Second, Humble's evidence showed that use of the reservoir for gas storage provided benefits that were in the public interest.[49] Having disposed of the injunction, the Supreme Court then turned to the question of ownership of the gas. First, the Court approved of the analysis and holding of *Murchison*that extraneous gas became personal property and remained personal property even when reinjected into a reservoir.[50] The Court then focused on the Wests' argument that the theory of confusion

41. 508 S.W.2d 812 (Tex. 1974).

42. *Id*. at 813. The West Clear Lake Field was included in a 1938 fee simple conveyance to Humble. *Id*. The West family members reserved a one-sixth royalty in gas produced from the field. *Id*. A brief history of James Marion West, Sr. and the West Mansion is available at the Texas Historical Commission's Texas Historic Sites Atlas. http://atlas.thc.state.tx.us/common/viewform.asp?atlas_num=2094001015&site_name=West,%20James%20and%20Jessie,%20Mansion&class=2001 (last visited Apr. 14, 2007).

43. *Humble*, 508 S.W.2d at 813.

44. *Id*. The West family members opposed Humble's application. *Id*.

45. *Id*. at 813-14.

46. *Id*. at 814.

47. *Id*.

48. *Id*. at 816.

49. *Id*. Humble's evidence showed a public benefit due to its ability to use the field as a peaking facility for natural gas storage and as an emergency facility capable of delivering gas in times of emergency or natural disaster. *Id*.

50. *Id*. at 817.

of goods supported the trial court's declaratory judgment.[51] Natural gas seems perfectly suited to confusion—"[a]s a general rule, the confusion of goods theory attaches only when the commingled goods . . . are so confused that the property of each cannot be distinguished."[52] In the event of a homogenous mixture, such as a combination of native and extraneous gases, each party may claim its fractional share of the mixture, provided that the commingling party can identify the share of each owner.[53] Failure to identify the fractional share places the loss on the commingling party.[54] Based on this calculus, Humble was liable to pay a royalty only on native gas remaining in the formation only if it could establish "with reasonable certainty" the volume of the native gas that would be produced "absent injection of extraneous gas.[55] Having reached these conclusions, the Supreme Court remanded the case to the trial court to see if Humble could make a showing of reasonable certainty in the estimation of the native gas reserve.[56]

At this juncture, the ground rules are becoming clearer. *Murchison* sets the baseline for ownership—produced (extraneous) gas is personal property that remains personal property even when reinjected into a subsurface storage formation. Even if the gas is commingled in the formation with native, not-yet-produced gas, the operator can preserve the personal property status of its gas by showing, with reasonable certainty, the amount of native gas that would be produced without injected gas. To those who think this approach is straightforward—meet *Bennie*.

In *City of Brady v. Bennie*,[57] the dispute again involved a gas storage field, this time operated by the City of Brady, and a well drilled on land overlaying the formation in which the city stored its gas.[58] The genesis of

51. *Id*. at 817-18.
52. *Id*. at 818.
53. *Id*.
54. *Id*.
55. *Id*. at 819.
56. *Id*. Ultimately, Humble changed its name, lost again in the trial court, and won in the court of appeals; the Wests had their application for writ of error refused (no reversible error) by the Texas Supreme Court and their petition for certiorari denied by the Supreme Court. Exxon Corp. v. West, 543 S.W.2d 667 (Tex. Civ. App.—Houston [1st Dist.] 1976, writ ref'd n.r.e.), *cert. denied*, 434 U.S. 875 (1977). At the retrial, Exxon called the only testifying witnesses (two experts employed by Exxon). *Id*. at 669. The court of appeals held that their testimony was sufficient evidence to establish with reasonable certainty the volume of gas that was economically recoverable from the field. *Id*.
57. 735 S.W.2d 275 (Tex. App.—Eastland 1987, no writ).
58. *Id*. at 278. Coincidentally, Lone Star Gas Company also played a role in the *Bennie* case. Lone Star entered into a gas purchase agreement with a corporation owned by Terry and Julie Bennie to buy gas produced from a well owned by the corporation. *Id*. Dr. J. L. Morris entered into a gas storage lease on three tracts of land with Brady Municipal Gas Corporation. *Id*. at 277. A series of transactions resulted in new leases of the three tracts, an assignment of the leases to Brady Gas, and a farmout agreement that led to the drilling of a well on one of the

the dispute was a letter sent by the city's attorney to Lone Star, the purchaser of gas under a contract with the well owner.[59] The attorney alleged that the corporation was producing gas injected by the city and cited the *Murchison* case as support for the proposition that the city retained title to gas the injected into the subsurface formation.[60] The attorney concluded with a claim for conversion of the gas by the corporation and a demand to Lone Star to suspend payments for the gas until the question of ownership could be resolved.[61] Unsurprisingly, a lawsuit was born. The corporation and its owners, the Bennies, sued the city alleging tortious interference with the Lone Star gas purchase agreement and slander of title.[62] Following a jury trial, the court entered judgment in favor of the Bennie parties.[63] The city appealed, contending, among other things, that the record did not contain any evidence to support the award of damages for loss of gas from March 5, 1984, to the date of trial.[64]

The court of appeals examined the record and found sufficient evidence to support the jury's determination of the volume of economically recoverable native gas under the Bennies' land before injection of extraneous gas, and an award of damages for loss of gas.[65] The court of appeals rejected the city's argument that the *West* case precluded the Bennies' recovery of damages because there was no evidence that the volume of gas found by the jury could be recovered without injection of gas by the city.[66] The gloss that *Bennie* puts on *West* is

Morris tracts. *Id*. The farmout agreement specified that completions in the well had to be above or below the gas storage formation. *Id*. Brady Gas then refused to make assignments of the tracts to the operator, contending that the operator completed the well in the storage formation. *Id*. Following a bankruptcy filing by Brady Gas, the city ended up owning the gas storage leases. *Id*.

59. *Id*. at 278.

60. *Id*.

61. *Id*.

62. *Id*. The Bennies and the corporation also sued the attorney, alleging libel. *Id*. Fortunately for the attorney, he received summary judgment and a severance from the case, leaving one to infer his name from the reference in the opinion to an unpublished affirmance of the summary judgment and severance. *Id*.

63. *Id*. at 277.

64. *Id*. at 280. Lone Star shut in the well on March 5, 1984, slightly less than one month after receiving the letter from the city's lawyer. *Id*. at 278. Among other things, the jury determined the volume of native gas economically recoverable from the Bennies' property on the date they acquired the tracts of land as well as a sum for the loss of gas during the relevant time period. *Id*. at 279-80.

65. *Id*. at 279-80.

66. *Id*. at 281. The court of appeals cited the *Exxon v. West* case as no support for the City's "pressure" theory of no recovery, i.e., that the gas could not be recovered without the city's injection of storage gas. *Id*. The court of appeals cited evidence offered by an expert for the Bennies that the composition of gas samples taken from native Bennies gas differed from the composition of native gas samples. *Id*. at 281-82.

that evidence that native gas will not be recovered without injection does not preclude a finding that the gas is recoverable.

Now, with *Bennie* added to the mix, injected natural gas (or carbon dioxide) does not lose its status as personal property unless its owner is unable to show with reasonable certainty the volume of native gas that can or will be recovered. The operator will owe a royalty on all native gas that is recovered, even if the native gas is recovered *as a result of the injection program*.

Applying these principles to MEOR operations, the operator should be able to maintain the personal property status of injected carbon dioxide by showing the amount of that gas present in the casinghead gas streams of each well.[67] These records provide the baseline for the native gas portion of the production stream. When data are coupled with post-MEOR well stream analyses, the amount of extraneous carbon dioxide in the casinghead gas stream can be determined with reasonable certainty.

IV. DOES CARBON DIOXIDE INJECTION VIOLATE ANY MARKETING DUTIES?

Another theory offered by royalty owners is a claim for the diminution in value of the casinghead gas stream as a result of MEOR operations. As discussed above, one of the effects of injecting carbon dioxide into an oil bearing formation is that the carbon dioxide dissolves in the crude oil.[68] When the ambient pressure of the produced fluids reaches atmospheric pressure at the surface, the carbon dioxide returns to its gaseous state, thus increasing the carbon dioxide content of the casinghead gas. Typically, gas processing plants have the capability of processing casinghead gas streams containing no more than a prescribed level of carbon dioxide.[69] When, as a result of MEOR operations, the carbon dioxide content of a gas stream exceeds that figure, the plant operator may reject the gas stream.[70] Under these circumstances, the gas stream will require processing to reduce the quantity of carbon dioxide to a level acceptable to the gas processing plant. The net effect is that the value paid by the plant for the casinghead gas stream is reduced as a result of the additional processing requirements. When this happens, the royalty

67. As a practical matter, this information should be readily available to the operator in the form of the periodic analyses of the production streams.

68. *See* Part I, *supra.*

69. *Id*.

70. Typically, the gas purchase agreement or the gas processing agreement will set standards for the quality of gas that it will accept and will provide the plant operator with the option to reject non-conforming gas streams. In the *Bennie* case, one of the city's arguments against the tortious interference claim was that Lone Star had a contractual right to reject gas in which the carbon dioxide content exceeded three percent. *Bennie*, 735 S.W.2d at 283-84.

owner will see a reduction in the amount of royalty received from the sale of casinghead gas. Rarely do royalty owners accept such outcomes without protest. The royalty owner's theory of a claim against the operator is that the operator's actions breach its contractual and implied duties to market the casinghead gas because the carbon dioxide MEOR operations has reduced the value of those hydrocarbons. This approach depends on the premise that the operator's duties with respect to casinghead gas are severable from the bundle of duties the operator owes the lessor.

The actions of the operator are, in general, measured by the express terms of the lease and, for implied duties, by the reasonably prudent operator standard.[71] An operator's duty to get the best price possible is loosely found in the implied duty to market (in proceeds applications) and is found in the express market value language of the royalty obligation in those applications.[72] Because few leases expressly state a severable duty to maximize the value of the casinghead gas stream, the operator's actions must be measured by what the reasonable operator of the lease (or unit) would do under the same or similar circumstances.[73] The royalty owners' argument is that a reasonably prudent operator must maximize the value of each component of the hydrocarbon stream in order to meet its obligations. Thus, by introducing carbon dioxide into the gas stream at levels that require additional processing expense, the operator is acting imprudently, which results in a diminished value for the native hydrocarbons in the now-contaminated casinghead gas. While this argument is appealing at the surface, the failure of the premise—severable duties—is a debilitating defect.

The inquiry begins with the purpose of the carbon dioxide MEOR program—to increase the amount of oil ultimately recoverable from the formation.[74] This starting position immediately reveals the inherent conflict between production of oil and casinghead gas in a MEOR operation. If the question is, "What would the reasonably prudent operator do?" and the operator believes that MEOR operations offer good prospects for significantly increasing the recovery of oil from a formation, then the results obtained following MEOR operations

71. *See e.g.*, Amoco Prod. Co. v. Alexander, 622 S.W.2d 563, 567-68 (Tex. 1981).

72. *See* Texas Oil & Gas Corp. v. Vela, 429 S.W.2d 866, 870-71 (Tex. 1969) (express duty to pay royalties on market value trumps economic reality of proceeds under long-term contracts).

73. *Alexander*, 622 S.W.2d at 567-68.

74. *See* Enhanced Oil Recovery, *supra* note 6. Actually the inquiry begins with the lease. If, in the unlikely event that the lease has express language creating separate duties to maximize the value of oil and casinghead gas, then the operator's royalty obligation on casinghead gas arguably would be governed strictly by the hydrocarbon content of the produced gas, as if the gas contained no carbon dioxide in excess of historical levels.

necessarily answers the duty question.[75] If MEOR operations result in increased oil production along the lines of historical results, the operator acted reasonably, even if the value of the casinghead gas stream is diminished. This bold statement is based on the by now well-known properties of a carbon dioxide flood—an increase in oil production and an increase in carbon dioxide in the casinghead gas stream. These results travel hand in hand. If the results are not severable, neither are the duties. An operator's successful decision to implement MEOR results inevitably in increased carbon dioxide content in the casinghead gas volumes.

If the operator acted reasonably in choosing to implement a MEOR program, what is left for the royalty owner? There is a chance that the royalty owner could fashion a claim based on the logic of the courts in *Bennie* and *West*. In *Bennie*, the court of appeals allowed the Bennies to recover damages based on the volume of economically recoverable native gas found by the jury to underlay the Bennies' land on the date they received title.[76] Royalty owners could argue that they are entitled to receive royalties on the amount of native gas remaining in the formation on the date MEOR operations commence. This approach is consistent with the *West* and *Bennie* cases. On the other hand, that is exactly what the royalty owners are getting paid for—the native gasses produced in the casinghead gas stream along with the injected carbon dioxide. Remember, the carbon dioxide injected by the operator has no BTU value.[77] The value or worth of the casinghead gas produced is based solely upon its heating value—which value can only derive from the native hydrocarbons mixed with it.[78] Further, the *West* and *Bennie* decisions dealt with issues primarily related to commingling of native and extraneous gases, which is not the issue in MEOR situations. Another problem for the royalty owner seeking a claim to level against an operator for "hurting" its casinghead gas value is that casinghead gas is produced only when oil is produced. MEOR operations result in the production of significant quantities of oil, and associated casinghead gas, that would not otherwise be brought to the surface. This fact brings to bear the economic recoverability principle of the *West* case. In other

75. Also, assuming the royalty fraction is the same for gas and oil, increased oil production from an oil well always will result in a net benefit to the royalty owner—despite the decrease in the value, and the royalty, of the casinghead gas. Historically, royalties on oil production from oil fields account for substantially more royalty revenues to the royalty owners than royalties for casinghead gas production.

76. Bennie, 735 S.W.2d at 279-80.

77. *See* note 19, *supra.*

78. Granted, in the case of gas contaminated with carbon dioxide, the value of the casinghead gas measured by its heating value is decreased by some factor to account for the costs of removing the carbon dioxide.

words, the *West* court's limitation of the offset owner's recovery to the economically recoverable reserves in place should eliminate this claim, because without the MEOR operations, there would be no oil, thus no casinghead gas.

V. ARE ROYALTIES OWED WHEN THE INJECTED CARBON DIOXIDE COMES FROM AFAR?

An entirely different set of issues arises when the carbon dioxide appearing in the casinghead gas stream was not injected by the operator. This situation may give the royalty owner a legitimate basis for claiming that the "foreign" carbon dioxide within the casinghead gas is subject to royalty burdens. But in regard to other claims, the royalty share will remain without remedy.

As discussed in Part I above, the Texas Railroad Commission holds the authority to approve of secondary and tertiary recovery operations.[79] The Texas Supreme Court, however, has made it clear that the legal, conforming actions of an operator conducting enhanced recovery programs approved by the Railroad Commission cannot form the basis of a cause of action against that injecting operator.[80] As a result, it appears unlikely that a royalty owner will be able to fashion a claim against the offset, injecting operator for doing something the Commission has approved.

This safeguard, however, may not extend to the royalty owner's own operator. Contrary to the discussion in Parts II and III above, a whole new dynamic between the operator and its royalty owners arises when the operator's wells begin producing injected carbon dioxide—but that carbon dioxide was injected by an unrelated neighboring operator.[81] As discussed above, when an operator injects carbon dioxide (as its personal property) into the producing formation, it remains its personal property (to the extent that it can be identified) because, *inter alia*, the operator does so with the expectation of recovering the injected carbon dioxide that is produced from its own wellbores. As such, the fact that the carbon dioxide began as personal property together with the fact that it was injected into the ground with the intention of recovering it at a later time indicates that the gas remained the personal property of the lessee operator. This was the essence of the holding in *Murchison*.[82] This

79. 16 TEX. ADMIN. CODE § 3.50 (2007).

80. R.R. Comm'n v. Manziel, 361 S.W.2d 560, 568 (Tex. 1962) ("a trespass does not occur when the injected, secondary recovery forces move across lease lines").

81. "Unrelated" in this context means that the adjoining operator is not unitized or pooled with the royalty owner's operator.

82. *Murchison,* 353 S.W.2d at 879-80.

principle was further refined in *Bennie*, in which the court engaged in a comparison of the original gas in place with the amount injected to derive a volumetric determination of how much gas an offset operator was allowed to recover from a common reservoir where gas was being stored by the City of Brady.[83]

The standards stated in these cases are absent when the produced substance—such as carbon dioxide—comes from someone other than the operator. In such cases, the neighboring operator will have commenced carbon dioxide enhanced recovery operations. As part of its plan and program, the injecting neighbor understands that some of its carbon dioxide, its personalty, will migrate across lease or unit lines to an adjoining tract.[84] This understanding is part of the simple physics of underground fluid dynamics. The same understanding is present in many waterflood operations, the effects of which have undergone judicial scrutiny in Texas. For example, the Texas Supreme Court has had occasion to determine the rights and responsibilities among adjacent interest owners when one has decided to begin enhanced recovery operations by injecting fluids in the ground.[85] In *Manziel*, the Supreme Court determined that if one operator undertakes to enhance oil recovery by injecting water pursuant to a valid Railroad Commission order, the adjoining operator has no basis in law to complain about the negative effects of water encroachment on its wells caused by these waterflood efforts.[86] In these situations, the water-injecting operator has no responsibility to compensate his neighbor for any of the negative effects of the increased presence of salt water.[87] In other words, Texas courts impliedly hold that the saltwater injected by the adjoining operator, which was its personalty before injection, changes nature as it crosses lease or unit lines because the portion of the injected salt water that migrates to adjoining lands becomes the responsibility of the non-injecting neighbor to handle.[88] That is, the injected salt water loses its

83. *Bennie*, 735 S.W.2d at 279-82.

84. Considerations such as this are part of the process outlined by the Railroad Commission in the Texas Administrative Code.

85. *Manziel*, 361 S.W.2d at 569.

86. *Id*.

87. This is the concept proffered as the "negative rule of capture." *Id*. at 568-69 ("Just as under the rule of capture a land owner may capture such oil and gas as will migrate from adjoining premises to a well bottomed on his own land, so also may he inject into a formation substances which may migrate through the structure to the land of others, even if it thus results in the displacement under such land of more valuable with less valuable substances.") (quoting PATRICK H. MARTIN & BRUCE M. KRAMER, WILLIAMS AND MEYERS: OIL AND GAS LAW § 204.5, fn 1 (2d ed. 2004)).

88. *Id*.

personalty characteristics (who would claim it anyway!) and returns to *ferae naturae*, the concept abandoned in *Murchison.*[89]

So, the question centers on whether injected carbon dioxide that migrates to an adjoining tract is more closely affiliated with salt water injected for secondary recovery operations (*Manziel*) or natural gas injected for future recovery from the injecting party's own wells (*Murchison*). The primary focus of the gas storage cases is the intention of the natural gas injector to store and then recover the amounts injected from its own wells.[90] To the contrary, the operator injecting fluids for enhanced recovery understands that it will not recover from its own wells the injected fluids that migrate off the premises.[91] Because carbon dioxide is a fluid that, once injected, is not realistically expected to be recovered if it migrates across unit or lease lines, it should be characterized as original gas in place from the perspective of the operator producing such carbon dioxide and its royalty owners. Thus, when dealing with carbon dioxide injected by a neighbor but produced as part of the casinghead gas stream from its own wells, the operator should include this carbon dioxide as part of the volumes of casinghead gas used to calculate royalties.

This scenario raises interesting questions. As noted in Parts I and III, the mere presence of significant levels of carbon dioxide has a substantial negative impact on the market value of the casinghead gas. This situation will likely persist until the market value of "pure" carbon dioxide reaches a level where the producers can demand better terms. At this time, however, even if a royalty owner is "credited" with the carbon dioxide, it may be like winning the ugliest dog contest—you have a trophy, and your dog is still ugly. In other words, the casinghead gas, *your casinghead gas*, now brimming with carbon dioxide from the neighbor's injection activities, is worth less because the purchasing plant will offer worse

89. This analysis asks for a review of the basis for the *Murchison* decision—namely, the accepted principles of hydrocarbon flow within producing formations. This area has expanded since 1962; *Murchison* steered away from the *ferae naturae* concept (supporting the rule of capture) in favor of the then-current understanding that hydrocarbons remained relatively static in the ground—especially once injected. Modern technology has proven this static principle of fluid behavior wrong. Fluids underground move with abandon—somewhat predictable abandon—but abandon nonetheless. *See* Office of Natural Gas and Petroleum Technology, Advanced Diagnostics & Imaging Systems Program, at 13 (1999), available at http://www.fossil.energy.gov/programs/oilgas/publications/programplans/1999/2diag.pdf. (A DOE/industry cosponsored field test has shown how time can be included in the geologic portrait, which, in effect, adds a fourth dimension to seismic imaging. The result is an entirely new way to examine fluid movement in an oil reservoir.) Thus, the *ferae naturae* basis of support for the rule of capture may have life yet.

90. *See* Yzaguirre v. KCS Res., Inc., 53 S.W.3d 368, 372 (Tex. 2001). *See also West*, 508 S.W.2d at 816.

91. B. Kirkendall & J. Roberts, *Probing the Subsurface with Electromagnetic Fields*, SCIENCE AND TECHNOLOGY REVIEW, Nov. 2001, available at www.llnl.gov/str/November01/Kirkendall.html.

terms. Further, because one of the base assumptions in this analysis is that the royalty owner's own operator is not injecting carbon dioxide,[92] this same operator cannot "use" the carbon dioxide.[93] Also, despite the fact that the purchasing plant might reap substantial benefits from sales of the separated carbon dioxide to local injectors, the plant's contract with the royalty owner's non-injecting operator likely will reflect the depressed terms usually seen on casinghead gas contracts, or gas purchase agreements, involving casinghead gas contaminated with carbon dioxide.

In summary, carbon dioxide injected by a neighboring operator will become part of the gas stream of the operator that produces them, and subject to royalties. The contracts upon which royalties are based for casinghead gas, however, do not favor high levels of carbon dioxide, so the royalty owner is left in the situation similar to that of its own operator—receiving a benefit from the enhanced oil production but experiencing some loss in market value of the gas (and the proceeds received for its gas) due to the presence of carbon dioxide—a loss that is allowed and sanctioned by a logical extension of Texas jurisprudence. About the only real option available to the royalty owner is an inquiry of other plants potentially within reach of the lease to determine if the terms they offer for the contaminated gas exceed those accepted by its lessee operator.

VI. APPLICATION OF THE DISCOVERY RULE TO ROYALTY LITIGATION INVOLVING CARBON DIOXIDE PRODUCTION

As discussed above, carbon dioxide production resulting from tertiary recovery operations in which the gas is injected into the producing formation excites inquiry regarding to whom the gas belongs (and the royalty effects thereof) and the royalty litigation potential stemming from its effect on the quality of the casinghead gas stream. Regardless of the outcome of that inquiry, however, damage calculations in royalty litigation stemming from production of injected carbon dioxide will be limited by the application of the statute of limitations and the doubtful availability of the discovery rule to avoid the statute in these cases.

Statutes of limitations are creations of the legislature designed to reduce stale claims and provide certainty and closure to those potentially responsible for claims.[94] Because most claims for failure to pay royalties,

92. That would add a level of complexity beyond the scope of this article.

93. A situation that might trigger the "use off of the premises" royalty clause.

94. For an excellent discussion of statutes of limitations, and the discovery rule exception to their application to royalty lawsuits, *see* Dick Watt, Donato D. Ramos, and John Beckworth, *Royalty Litigation in 2004: An Update and a Look Ahead*, presented at the Page Keeton Civil Litigation Conference (October 28-29, 2004).

or failure to pay the proper amount of royalties, are based on breach of contract (whether the terms allegedly violated are express or implied), Sections 16.004 and 16.051 of the Texas Civil Practice and Remedies Code provide the basis for the statutes of limitations invoked in royalty cases.[95] These statutes set a specific period of time within which a claimant—the royalty owner—may bring a lawsuit for damages. The time frame for bringing an action for breach of the express royalty clause, or breach of an implied duty to market that affects royalty valuations, is four years.[96]

In response to this bright-line cutoff, several exceptions to the statute of limitations have arisen over the years. One of these exceptions is the discovery rule.[97] The discovery rule provides that an otherwise applicable statute of limitations will not begin until the time at which the injury is actually discovered or, under the exercise of reasonable diligence, should have been discovered.[98] As originally articulated, the Texas Supreme Court discussed the discovery rule by relying on rhetoric that only certain classes, or types, of cases, qualified its application.[99] Later, the Court refined this analysis (to bring consistency to the jurisprudence) to focus the inquiry on whether the claim was (1) inherently undiscoverable and (2) objectively verifiable.[100] This approach was also stated as a determination of whether the case at bar was the type of case where, generally, a party would be capable of detecting the facts that would lead it to discover the potential for a lawsuit.[101] In conducting this analysis, the Texas Supreme Court advised that whether the parties in question actually knew of the potential lawsuit (or its underlying facts) was irrelevant—in fact, in *Altai* everyone acknowledged that the plaintiff was unaware of the facts that would have put it on notice of an alleged theft of trade secrets.[102] Regardless, the Supreme Court stated that theft of trade secrets was the type of dispute where, generally, the aggrieved party would be able to detect the theft within the time provided by the statute of limitations. This "general" inquiry is a question of law for the trial judge to answer before the jury is given a question as to whether, and

95. *See* TEX. CIV. PRAC. & REM. CODE ANN. §§ 16.004, 16.051 (Vernon Supp. 2006).

96. *See* note 93*, supra.*

97. *Id*.

98. Computer Assoc., Int'l v. Altai, Inc., 918 S.W.2d 453, 455 (Tex. 1996), *certifying questions applied by*, 126 F.3d 365, 235 (2d Cir. 1997).

99. *See, e.g.,* Willis v. Maverick, 760 S.W.2d 642, 644-45 (Tex. 1988) (creating a new "class" of discovery rule cases, legal malpractice, and acknowledging the other classes then existing—medical malpractice, credit libel, and fraud).

100. *Altai*, 918 S.W.2d at 455-56.

101. *Id*. at 457.

102. *Id*.

when, the plaintiff actually knew or should have known of facts that did or would have put it on notice of the underlying cause of action.[103]

In the context of the discovery rule's application to claims by royalty owners, the Texas Supreme Court reached a seminal decision in *Neel v. HECI Exploration Co.* in 1998.[104] In *HECI*, the operator of a tract sued the operator of an adjoining tract for damages caused by the activities on the adjoining tract. The tract royalty owners, who admittedly did not learn of the litigation and its favorable settlement until many years later, sued the tract operator to be paid their royalty share of the operator's recovery from the adjoining operator. The Supreme Court reversed the Austin Court of Appeals, ruling that the royalty owners knew or should have known about the offset operator's misdeeds, and thus the alleged misdeed of their own operator (failing to notify them of their potential cause of action against the offset operator), within the time of the statute of limitations.[105]

In *HECI*, the Supreme Court framed its inquiry as "whether the discovery rule applies to cases of *this type*." [106] The Supreme Court focused on the premise that a royalty owner has an obligation to exercise reasonable diligence in protecting its own interests.[107] Importantly, the Supreme Court noted that "[r]oyalty owners cannot be oblivious to the existence of other operators in the area or the existence of a common reservoir."[108] The Court pointed to visible surface operations as another factor of inquiry notice.[109] Further, although not going so far as to say that records in the Texas Railroad Commission constituted constructive notice in all instances for royalty owners regarding operations in the area of their ownership, the Supreme Court noted that these records are "a ready source of information."[110] In light of all of the "generally" available information, the Texas Supreme Court ruled that a royalty owner's right to sue an adjoining operator for damaging a common reservoir was not the type of case that was inherently undiscoverable, thus the cause of

103. Once a court determines that the discovery rule is generally applicable to the type of dispute involved, the finder of fact will be presented with a question as to whether, under the particular facts of the case, the discovery rule shall apply. *See* STATE BAR OF TEXAS, TEXAS PATTERN JURY CHARGES – BUSINESS, CONSUMER, INSURANCE, EMPLOYMENT, PJC 102.23 (2006) (discovery rule question for DTPA lawsuits); *See also* Barker v. Eckman, 213 S.W.3d 306, 311-312 (Tex. 2006) (noting that discovery rule challenge was waived because of plaintiff's failure to submit a jury charge on the question).

104. Neel v. HECI Exploration Co., 982 S.W.2d 881 (Tex. 1998).

105. *Id*. at 884-87.

106. *Id*. at 885 (emphasis added).

107. *Id*. at 886.

108. *Id*.

109. *Id*.

110. However, some commentators have questioned the ability of royalty owners to ferret out information contained in the sometimes voluminous files at the Texas Railroad Commission. *See* WATT ET AL., *supra* note 94, at 73.

action against the royalty owner's own operator for failing to inform the owner of that right was discoverable too, and the discovery rule did not apply.[111]

In *Wagner & Brown v. Horwood*, the Texas Supreme Court added another situation in which the discovery rule was unavailable to a royalty owner, but this time the "type" of case was one for the underpayment of royalties.[112] In this case, the operator was alleged to have made improper deductions from the royalties due. The royalty owners sued after the time allowed under the four-year statute of limitations, pleading that the discovery rule applied to their claims.[113] The Supreme Court disagreed, referring to both the holdings in *HECI* and the particular factors at play with a claim of royalty underpayment to decide that a royalty owner ought to know, within the statute of limitations, of injuries caused by excessive or improper charges resulting in the underpayment of royalties.[114]

This backdrop sets the stage for the analysis of whether a royalty owner can avail itself of the protection of the discovery rule in a claim for failure to pay royalties, or for the "damage" to the royalty value of the gas stream, resulting from the production of carbon dioxide injected into a reservoir. As discussed in Part I above, MEOR operations are far from secretive. Extensive preparations, from the running of a new network of pipelines to the construction of a carbon dioxide recovery plant, will be visible. Often, the operator will contact the royalty owners to notify them of its intention to inject carbon dioxide. Further, in order to institute carbon dioxide injection activities, the operator must take all of the notification steps detailed earlier.[115] This process is much more open and detailed than the voluminous records the royalty owners in *HECI* bemoaned as too murky and confusing to put them on notice.[116] Moreover, the royalty owner, certainly on notice that a vast volume of carbon dioxide is about to flow through the system, also would be aware of the effect of these operations on its royalty check. First, the value of the royalty checks most likely will jump as the amount of oil produced soars. Moreover, the casinghead gas royalties likely will also vary as a result of the influx of carbon dioxide.[117]

111. *Neel*, 982 S.W.2d at 887-88.
112. Wagner & Brown, Ltd. v. Horwood, 58 S.W.3d 732, 734-35 (Tex. 2001).
113. *Id*. at 733-34.
114. *Id*. at 737.
115. *See* 16 TEX. ADMIN. CODE § 3.50 (2007).
116. *See* WATT ET AL., *supra* note 94.
117. This variance could be both up or down, and will likely exist whether carbon dioxide is noted as a separate source of royalty income or not.

Thus, in light of the sizable volume of information that the royalty owner "generally" would have at its disposal regarding carbon dioxide injection activities, Texas courts likely will not allow royalty owners to rely on the discovery rule to extend a claim that they might have for underpayment of royalties resulting from the production of injected carbon dioxide, whether such a claim is based on the failure to pay for volumes of the gas produced or instead is based on the diminution in value of the royalty owner's gas stream as a result of the introduction and presence of the contaminant.[118] This result is fair in light of the massive amount of information available to a royalty owner regarding these activities and their effect on production. Taking a wider view, the result also is fair because the royalty owner almost immediately enjoys the fruits of the carbon dioxide enhanced recovery operations through the increase in oil production and, therefore, in oil royalties.

VII. CONCLUSION

Innovations in the common law, necessitated by the advances in technology in drilling and production operations, are needed once again because of the rise in the number of leases and units in Texas affected by carbon dioxide injection operations. As has often happened in the past, these innovations involve one part reliance on established legal principals and one part of fresh interpretations of standing dogma. Using these guidelines, it appears that there should be no expansion of royalty obligations or claims for diminution in value occasioned by an operator's injection and recovery of carbon dioxide. Interestingly, although carbon dioxide should be included in the casinghead gas volumes subject to royalty obligations when the source is off the lease or unit, the reality of modern production and sales indicates that this additional volume has little if any value because carbon dioxide is a contaminant, which actually makes the casinghead gas less valuable than it would otherwise be. Finally, in the event that a royalty owner were able to prevail in claiming that royalties were due, the facts surrounding the nature of carbon dioxide injection activities almost guarantee that such claims would be limited by the four-year statute of limitations because the discovery rule

118. A likely counterargument to this result would stem from a royalty owner relying on two appellate court decisions that predate the *HECI* and *Wagner & Brown* decisions: *Houston Endowment, Inc. v. Atlantic Richfield Co.*, 972 S.W.2d 156 (Tex. App. – Houston [14th Dist.] 1998, no pet.), and *Dorchester Gas Producing Co. v. Hagy*, 748 S.W.2d 474 (Tex. App. – Amarillo 1988, writ dism'd by agr.). Such reliance would be misplaced. These cases predate the analytical framework set up in *HECI* and *Wagner & Brown* and thus do not employ the approach required by the Texas Supreme Court for lower courts conducting a discovery rule analysis in the lessor-lessee context. More specifically, neither *Houston Endowment* nor *Dorchester* try to determine whether their situations involved the type of dispute to which the discovery rule generally, or typically, would apply.

will not apply. Despite these apparently unfavorable results the royalty owner likely will experience in litigation over royalties for injected carbon dioxide, it should not lose sight of the fact that the carbon dioxide injection activities greatly enhanced its oil production and the royalties that resulted from that increase.