



January 2002

Oil, Gas and Mineral Law

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Recommended Citation

Richard F. Brown, *Oil, Gas and Mineral Law*, 55 SMU L. REV. 1219 (2002)
<https://scholar.smu.edu/smulr/vol55/iss3/19>

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OIL, GAS AND MINERAL LAW

Richard F. Brown*

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I. INTRODUCTION

THIS article focuses on the interpretations of, and changes relating to, oil, gas, and mineral law in Texas from October 1, 2000 through September 30, 2001. The cases examined include decisions of courts of the State of Texas and the Fifth Circuit Court of Appeals.¹ There was a dramatic increase this year in the number of oil, gas, and mineral law cases. This increase, coupled with the necessity of including legislation of interest, has resulted in a more selective approach in choosing which cases to report. Unpublished cases are not included.

II. CONVEYANCING ISSUES

*John G. and Maria Stella Kenedy Mem'l Found. v. Dewhurst*² reaffirms the general rule that the shoreline for civil-law littoral tracts is the upper

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1. This article is devoted exclusively to Texas law. Cases involving questions of oil, gas, and mineral law, decided by Texas courts but applying laws of other states, are not included.

2. 44 Tex. Sup. Ct. J. 268, slip op., No. 99-0667, 2000 WL 1862934 (Dec. 21, 2000).

level of the shore as located under the methodology described in the *Luttes* case, but finds an exception for a significant part of the shoreline of the Laguna Madre. *Luttes v. State*³ holds that the shoreline of civil-law (Spanish grant) tracts is at the mean higher high tide.⁴ The mean higher high tide used to determine the littoral boundary under a civil-law grant is a datum or plane calculated by obtaining daily water measurements from tide gauges and then averaging all daily high tides over the full 18.6 year tidal cycle.⁵ Tide gauges reflect water level changes, whether produced by astronomical factors, weather conditions, or a combination of both.⁶ In the *Kenedy Memorial Foundation* case, the calculation began with the data from the tide gauges, but because of the unique physical characteristics of the disputed area, the line of mean higher high tide could not be calculated using the usual National Oceanic and Atmospheric Administration (NOAA) methodology.⁷ In fact, the NOAA refused to certify tide gauges in the disputed area.⁸

The disputed area is part of the shoreline of the Laguna Madre. The Laguna Madre is a body of water between the Texas coast and Padre Island. At issue was "ownership of about 35,039 acres of coastal land along the shore of the Laguna Madre."⁹

The Foundation claimed that *Luttes* controlled, and the Foundation produced expert testimony as to the location of the boundary. Although the Foundation's experts never attempted to calculate mean higher high tide, they testified that essentially the entire Laguna Madre fell within the grant (but the Foundation only claimed to the coastal side of the Intracoastal Waterway). The State contended that the correct line was about six miles further west as surveyed by Darrell Shine. The State-sponsored Shine survey was "based upon historical evidence substantially contemporaneous with the grants."¹⁰ The State contended that the *Luttes* opinion permitted an exception to the methodology approved in *Luttes* and that the location and unique geography made it impossible to apply the *Luttes* formula.¹¹

The court agreed with the State that *Luttes* left open the possibility that the civil-law shoreline could be located at a place other than the mean higher high tide line, if the mean higher high tide line as calculated did not accurately reflect the shoreline.¹² The ultimate objective was to locate with reasonable accuracy "the upper level of the shore (the shoreline) of the area regularly covered and uncovered by the sea over a long

3. 324 S.W.2d 167 (1958).

4. *Id.* at 191.

5. *Id.* at 169, 174 (citing *Tidal Datum Planes*, U.S. Dep't of Com., Coast and Geod. Survey, Special Publication No. 135, Rev. Ed. at 86 (1951)).

6. *Id.* at 173.

7. *Kenedy Mem'l Found.*, 2000 WL 1862934, at *1.

8. *Id.* at *10.

9. *Id.* at *1.

10. *Id.* at *3.

11. *Id.* at *9.

12. *Kenedy Mem'l Found.*, 2000 WL 1862934, at *13.

period of time.”¹³ Using historical evidence was an acceptable methodology before *Luttes*, and the court held that using historical evidence was appropriate when the NOAA methodology required by *Luttes* could not be calculated and the location of the shoreline had not changed from the original grant.¹⁴ The Shine survey was based on prior maps and surveys, the patent, prior court cases, information from NOAA, and aerial photographs.¹⁵ The jury found and the court confirmed that the Shine survey marked with “reasonable accuracy the line between the fast land and the shore of the Laguna Madre.”¹⁶ The court reaffirmed the methodology used in the *Luttes* case for civil-law seashore boundaries and limited their holding to the facts of the *Kenedy Mem’l Found.* case.¹⁷

*Reagan v. Marathon Oil Company*¹⁸ reaffirms that a conveyance of minerals in a tract adjacent to a highway will presumptively convey minerals to the center of the highway under the doctrine of “strips and gores.” It is settled under that doctrine:

[A] conveyance of land bounded on a public highway carries with it the fee to the center of the road as part and parcel of the grant. Such is the legal construction of the grant unless the inference that it was so intended is rebutted by the express terms of the grant.¹⁹

The language used in the deeds reviewed in this case, which referred to the “north line” of the road and along the “south line” of the road, were found insufficient to “rebut the presumption that a deed conveying property adjoining a public highway carries with it title to the center of the road.”²⁰

*Senn v. Texaco, Inc.*²¹ holds that purchasers of the surface estate have no standing to sue for a permanent nuisance claim that accrued to the prior owner of the land. Senn purchased the surface of the Covered “S” Ranch in 1997.²² Senn sued former and current operators for permanent and temporary injury to his land from contamination of the aquifer underlying the land. This appeal resulted from a summary judgment dismissing the claim as to the former operators for lack of standing.²³ It was undisputed that the drilling and production activities of Texaco et al. ceased before the land was conveyed to Senn. The court followed the well-established rule in Texas that:

Where injury to land results from a thing that the law regards as a permanent nuisance, the right of action for all the damages resulting

13. *Id.*

14. *Id.*

15. *Id.* at *15.

16. *Id.* at *16.

17. *Kenedy Mem’l Found.*, 2000 WL 1862934, at *16.

18. 50 S.W.3d 70 (Tex. App.—Waco 2001, no pet.).

19. *Id.* at 77 (quoting *State v. Williams*, 335 S.W.2d 834, 836 (1960) and other authorities).

20. *Id.* at 80.

21. 55 S.W.3d 222 (Tex. App.—Eastland, pet. denied).

22. *Id.* at 224.

23. *Id.*

from the injury accrues to the owner of the land *at the time the thing that causes the injury commences to affect the land*. Stated another way, a cause of action for injury to real property is a personal right which belongs to the person who owns the property at the time of the injury. The right to sue for injury to the land is not a right that runs with the land.²⁴

Senn argued that by application of the discovery rule, Senn, not Senn's assignor, owned the cause of action, because Senn discovered the injury to the aquifer. The court refused to find that the discovery rule could work to transfer ownership of a cause of action.²⁵ The court refused to alter the existing "bright line" rule for determining ownership of the cause of action. The conveyance to Senn was without warranty, except as to title, and Senn's claim that his vendor had conveyed the vendor's rights against Texaco et al. to Senn was summarily dismissed.²⁶

III. OIL, GAS AND MINERAL LEASES

A. LEASE TERMINATION

*Natural Gas Pipeline Co. of America v. Pool*²⁷ is the first of several lease termination cases out of the Amarillo court. The Texas Panhandle has spawned a cottage industry based on the difficulty inherent in defeating lease termination claims that are twenty or thirty years old. Railroad Commission records are used as the original source to identify periods of no production, then the impossible burden shifts to the operator to come up with an explanation for the cessation of production. Because the petition for review has been granted in this and several of the other cases reported below, it is likely that there will soon be a significant opinion on lease termination from the Texas Supreme Court.

In *Pool*, the cessation of production occurred at least 29 years prior to the filing of suit, although the lessee continued to produce two wells on the lease and even drilled a third well on the lease in 1996.²⁸ Pool sued for lease termination, trespass and conversion. The trial court granted partial summary judgment on lease termination. Pool's proof was Railroad Commission Production records on the two known wells showing three time intervals in which both wells failed to produce. Although Pool failed to negate the possibility that there may have been other wells, the court rejected that possibility as mere speculation.²⁹

The lease had no savings clauses, and Natural Gas Pipeline Company of America (NGPL) sought to invoke the temporary cessation doctrine. The court held that Pool was not required to produce any evidence on

24. *Id.* at 225 (emphasis in original) (citations omitted) (citing *Vann v. Bowie Sewerage Co.*, 90 S.W.2d 561, 562 (Tex. 1936)); *Lay v. Aetna Ins. Co.*, 599 S.W.2d 684, 686 (Tex. Civ. App.—Austin 1980, writ ref'd. n.r.e.).

25. *Senn*, 55 S.W.3d at 226.

26. *Id.*

27. 30 S.W.3d 618 (Tex. App.—Amarillo 2000, pet. granted).

28. *Id.* at 624-25.

29. *Id.* at 625.

whether the lease was producing in paying quantities, because the evidence established that there was no production at all. Furthermore, the burden was upon the lessee NGPL to prove that the cessation of production fell within the temporary cessation doctrine. NGPL's only proof was a generic affidavit from the employee who was the Area Superintendent of Gas Measurement for NGPL from 1958-86. Although he testified to NGPL's general policies and procedures, he did not testify as to any specific facts on these specific wells or as to the time intervals in which no production was shown by Railroad Commission records. The court found that this was not enough to create a fact issue and affirmed the partial summary judgment on termination.³⁰

The case went to trial on the remaining issues, including NGPL's affirmative defenses. NGPL lost with the jury on laches, and the court overruled NGPL's point on laches, notwithstanding the obvious difficulties for NGPL in producing witnesses and documents after 29 years. The court, citing *Rogers v. Ricane Enterprises*,³¹ held that "[l]aches is not a defense in a trespass to try title suit where the plaintiff's right is based on legal title."³² *Pool* was not a suit in trespass to try title, but the court extended the effect of *Rogers* to include suits for declaratory relief as to title.

NGPL lost with the jury on the revivor defense, which was based on Pool's execution of division orders over the years. The court held that division orders can support a revivor only if the lessee has detrimentally relied upon them. NGPL drilled a third well and there was evidence that NGPL would not have drilled the well if it had known the lease had terminated. However, there was also some evidence that NGPL did not rely upon the division orders, which was enough to sustain the jury finding.³³

NGPL lost with the jury on adverse possession. Although NGPL exercised dominion and control over the acreage under lease for over sixty years, the court found that none of that conduct was inconsistent with its rights as lessee. "Because the original possession of the property by [NGPL] was not only permissive, but also consistent with [Pool's] concurrent interest in the property, adverse possession cannot be established unless notice of the hostile nature of the possession or repudiation of [Pool's] title is clearly manifested."³⁴ The court found that there was no evidence of repudiation, and further rejected NGPL's argument that if NGPL became a trespasser upon lease termination, such possession could not have been permissive. The court found that "entering property without consent is not necessarily the same as claiming ownership of the property by that entry."³⁵

30. *Id.* at 626-27.

31. 772 S.W.2d 76, 80 (Tex. 1989).

32. *Pool*, 30 S.W.3d at 627 (alteration in original).

33. *Id.* at 628.

34. *Id.* at 629.

35. *Id.*

The jury awarded damages for bad faith trespass. NGPL argued that entry must have been permissive until Pool filed suit. The court held that silence does not necessarily make the entry permissive, and good faith is determined not by whether the entry was permissive, but by the belief of the trespasser that he has "the right to enter and develop the minerals."³⁶

The jury awarded exemplary damages for fraud, which the court reversed for no evidence. There is generally no duty to disclose, and "Texas law has not recognized a fiduciary relationship between a lessee and royalty owners."³⁷ There was some evidence that Pool knew about the termination, there were many sources from which he could have learned of the termination, and there was no evidence that NGPL fraudulently misrepresented the facts.³⁸

The court upheld the jury finding of bad faith trespass, because there was some evidence of bad faith.³⁹ The award of actual damages was reduced to \$1,049,502.56, because the court found the two-year statute of limitations as to trespass and conversion governed the case.⁴⁰ The court concluded that the award of attorney's fees to Pool could not be sustained under the declaratory judgment statute, because the case was "essentially an action for trespass to try title and not for declaratory judgment."⁴¹ However, because NGPL asserted adverse possession as a defense, the trial court could award attorney's fees to Pool as the prevailing party in a trespass to try title case.⁴²

*Natural Gas Pipeline Co. of America v. Pool*⁴³ is a lease termination case out of the Amarillo court and is a companion case to the opinion reported immediately above. The facts and the issues are substantially the same, except that Natural Gas Pipeline Company of America (NGPL) had more success with the jury on its affirmative defenses.

NGPL secured a favorable jury finding on adverse possession, but the trial court entered judgment notwithstanding the verdict. It was again undisputed that NGPL had conducted operations on the lands for decades, but again the court held this was not enough to put Pool on notice that NGPL had repudiated the lease. Because the original entry by NGPL was "not only permissive, but also consistent with [Pool's] concurrent interest in the property, adverse possession [could] not be established unless notice of the hostile nature of the possession or repudiation of [Pool's] title [was] clearly manifested."⁴⁴

NGPL secured a favorable jury finding on laches, but the trial court entered judgment notwithstanding the verdict. It was again undisputed

36. *Id.* at 630.

37. *Pool*, 30 S.W.3d at 633.

38. *Id.* at 632-34.

39. *Id.* at 634-35.

40. *Id.* at 635 (citing TEX. CIV. PRAC. & REM. CODE ANN. § 16.003 (Vernon Supp. 2000)).

41. *Id.* at 637; see also TEX. CIV. PRAC. & REM. CODE ANN. § 37.009 (Vernon 1997).

42. *Pool*, 30 S.W.3d at 637.

43. 30 S.W.3d 639 (Tex. App.—Amarillo 2000, pet. granted).

44. *Id.* at 644.

that the delay of 14 to 57 years in bringing suit made it difficult for NGPL to find documents and witnesses, but again the court held that laches is not a defense in a suit for declaratory judgment to clear title to an oil and gas lease when plaintiff's right is based upon legal title.⁴⁵

The extent to which NGPL was entitled to a credit against damages for good faith improvements presented an issue not addressed in the first *Pool* case. Although the jury found good faith, the jury awarded nothing for the credit. The court held that the measure of damages for a good faith trespass is the "value of the minerals at the surface, less the costs of mining, extracting and hoisting the minerals to the surface."⁴⁶ Pool admitted that NGPL was entitled to a credit of \$161,750.80 for the costs of gathering, compression and treating, but disputed NGPL's right to a credit for lease expenses and overhead. The court awarded an additional \$115,715.29 for lease expenses and overhead, so that the judgment for damages was reduced by a total of \$277,466.09 for the same period during which damages were incurred.⁴⁷

*Natural Gas Pipeline Co. of America v. Law*⁴⁸ is a lease termination case out of the Amarillo court holding that a terminated lease was revived by a recorded family settlement agreement. There were two producing wells on the Haas lease, which had been held by production since 1934. Suit was filed for lease termination and damages for conversion approximately 36 years after the last interruption in production in 1964. The trial court granted partial summary judgment as to lease termination and submitted the remaining issues to the jury, including NGPL's affirmative defenses. NGPL obtained favorable findings on adverse possession and on revivor. The trial court rendered judgment notwithstanding the verdict that the lease had terminated and awarded damages to the lessors.⁴⁹

The court reversed and rendered on the sole question of revivor. There was evidence that before 1979 the lessors were aware of production issues affecting the lease.⁵⁰ On December 28, 1979, the ten owners of the mineral interests in the land signed a family settlement agreement. The principal purpose was to clarify the various changes in ownership that had occurred and to appoint an agent to act for the owners with respect to the lease. The agreement identified the land and the mineral rights as "now subject to an oil and gas lease in favor of Natural Gas Pipeline Company of America, Lease #8070- O & G, known as Mary Haas #1 and #3."⁵¹ The division of interest expressed in the agreement recited that "the said mineral rights and lease are now owned in proportions as follows. . . ."⁵²

45. *Id.* at 645-46.

46. *Id.* at 651.

47. *Id.* at 650-51.

48. 65 S.W.3d 121 (Tex. App.—Amarillo 2001, pet. filed).

49. *Id.* at 123.

50. *Id.*

51. *Id.* at 124.

52. *Id.* at 125

The agreement was recorded in the deed records of Moore County.⁵³

The court found that the agreement was a revivor of the lease.⁵⁴ The factors that it considered important were that it was a formal document, professionally prepared; it described the land as “now subject” to the lease; it expressly identified the lessee, the land, the wells, the lease number; and the use of the word “now” indicated the existence of the lease in 1979.⁵⁵

Lessors cited the Texas division order statute for the principle that “the execution of a division order does not revive a lease.”⁵⁶ The court refused to find that the agreement was a division order as described in the statute. Moreover, the court held that the statutory provisions could not apply to the 1979 agreement because “the provisions were not enacted until 1983 and do not have retroactive effect that would alter substantive rights.”⁵⁷

*Anadarko Petroleum Corp. v. Thompson*⁵⁸ is another lease termination case out of the Amarillo court. It holds that the words “as long thereafter as gas is or *can be produced*”⁵⁹ in the habendum clause of a lease implicitly means *actually* produced.⁶⁰ Thompson’s lease to Anadarko included a 60-day cessation of production clause, and Anadarko did not argue that there was “no cessation of production or temporary cessation of production.”⁶¹ Instead, Anadarko urged a literal reading of the habendum clause, because the well was apparently always capable of producing.⁶² The court rejected this argument and relied heavily upon *Garcia v. King*.⁶³ *Garcia* construed the words “as long thereafter as oil, gas and other minerals *is produced*”⁶⁴ in the habendum clause of a lease as implicitly meaning “in paying quantities.”⁶⁵ *Garcia* also looked to the objectives of the parties in entering into the lease and concluded that economic benefit was one of the objectives.⁶⁶ Because a literal interpretation might allow the lessee to hold the lease merely for speculation purposes (although there was apparently no evidence of that in this case), the court concluded that “can be produced” must mean more than mere physical ability to produce⁶⁷ and held that “can be produced” means actual

53. *Natural Gas Pipeline*, 65 S.W.3d at 126.

54. *Id.* at 128.

55. *Id.* at 126.

56. *Id.* at 128 (citing TEX. NAT. RES. CODE ANN. §§ 94.401-.402 (Vernon 1993 & Supp. 2001)).

57. *Id.* (citing Act of May 12, 1983, 68th Leg., R.S., Ch. 228, § 1, 1983 Tex. Gen. Laws 966).

58. 60 S.W.3d 134, 137 (Tex. App.—Amarillo 2000, pet. granted).

59. *Id.* at 137 (emphasis added).

60. *Id.* at 137-40.

61. *Id.* at 141 n.2.

62. *Id.* at 138.

63. 164 S.W.2d 509 (Tex. 1942).

64. *Id.*

65. *Thompson*, 60 S.W.3d at 138 (emphasis added).

66. *Id.* at 139.

67. *Id.*

production.⁶⁸

Anadarko also appealed the trial court's denial of all of its affirmative defenses. The court tested the record under the no evidence standard and found some evidence to support the trial court as to each defense.⁶⁹ The break in production occurred twelve years before suit was filed.⁷⁰ The court rejected adverse possession as a defense because at trial Anadarko asserted it never intended to abandon the lease, which was some evidence that it did not repudiate the lease and some evidence that Anadarko's claim was not hostile - both necessary elements of an adverse possession defense.⁷¹ The defense of quasi-estoppel (lessors accepting benefits over many years) was rejected because there was some evidence that Thompson did not know the lease had terminated until approximately the time the suit was filed.⁷² Laches was rejected for the same reason,⁷³ and because laches cannot be used to defeat the legal title which automatically reverted to Thompson upon cessation of production.⁷⁴ Anadarko urged revivor based on division orders, transfer orders, deeds, and other documents. The court rejected each of the documents presented, because they did not expressly revive the lease in question. There were no words of grant, the lease was never specifically identified, and the words relied upon were simply generic to printed forms.⁷⁵

*Krabbe v. Anadarko Petroleum Corp.*⁷⁶ is a lease termination case which analyzes the temporary cessation of production doctrine and applies it in a way which is generally favorable to the lessee. The consolidated lease at issue in the case was a very old form of lease and did not contain a shut-in clause, a cessation of production clause, a *force majeure* clause, or any other savings clause.⁷⁷ There were two producing wells on the lease, and each was subject to separate marketing arrangements. The Rockwell 1-102 was completed in 1931 in the Brown Dolomite formation, and the gas production was subject to a long term gas contract. The Rockwell B1R was completed in 1961 in the Red Cave formation, and the gas production was being processed through the Turkey Creek gas plant.⁷⁸ Production from the Rockwell 1-102 ceased for nineteen months in about 1985. The long term gas contract expired, negotiations began over the terms of a renewal, negotiations broke down, litigation resulted, and eventually production resumed.⁷⁹ Production from the Rockwell B1R held the lease during this nineteen month interruption, except that

68. *Id.* at 140.

69. *Id.* at 141-45.

70. *Thompson*, 60 S.W.3d at 141.

71. *Id.*

72. *Id.* at 142.

73. *Id.*

74. *Id.* at 141-42.

75. *Thompson*, 60 S.W.3d at 142-45.

76. 46 S.W.3d 308 (Tex. App.—Amarillo 2001, no pet. h.).

77. *Id.* at 311, 319.

78. *Id.* at 311-12.

79. *Id.* at 312.

the Rockwell B1R was itself shut-in for 92 days, and again for 61 days, during the same term. Both of these interruptions were attributable to mechanical work at the Turkey Creek Plant.⁸⁰

With no savings clause, the lease would terminate immediately upon the cessation of production, except for the operation of the implied temporary cessation of production clause. The operation of that clause has been summarized as follows in the leading Texas case of *Watson v. Rochmill*⁸¹:

It appears to be very well settled that under the terms of the lease [under consideration], upon cessation of production after termination of the primary term, the lease automatically terminated. The strictness of the above rule has been modified where there is only a temporary cessation of production due to sudden stoppage of the well or some mechanical breakdown of the equipment used in connection therewith, *or the like*. Under such circumstances, . . . the lessee is entitled to a reasonable time in which to remedy the defect and resume production.⁸²

The troublesome issue is to determine the scope of the phrase "or the like" in defining the universe of interruptions in production which will be excused by the implied temporary cessation of production clause.

Krabbe contended that "the cessation of production doctrine should be limited to cessations due to causes arising prior to the point of sale of gas from the well, or to physical or mechanical causes."⁸³ After reviewing the principal Texas authorities, the court unequivocally rejected this contention.⁸⁴ The court appears to have left the trial court free to consider evidence of any cause resulting in an interruption in production and evidence of any action taken to restore production. The result is to redirect the inquiry in a more useful direction to both the lessee's intent and the objective evidence of the lessee's intent as manifested in lessee's efforts to restore production.⁸⁵ In fact, the court was more concerned with whether the lessee acted in good faith and with due diligence.⁸⁶

80. *Id.* at 312-13.

81. 155 S.W.2d 783 (Tex. 1941).

82. *Id.* at 784 (citations omitted) (emphasis added).

83. *Krabbe*, 46 S.W.3d at 318.

84. *Id.*

85. *See, e.g., id.* at 317-18 ("In contrast to the facts in *Watson*, [155 S.W.2d 783 (Tex. 1941)] the record before us does not reflect that either Anadarko or Cabot intended to cause wells that could produce gas to cease production for an indefinite length of time because production was not economic, or for any other reason The record reflects that during the periods of non-production in August, September and October, 1985 and May and June 1986, Anadarko was continuing its quest to have Cabot resume accepting gas from 1-102 under the agreement Anadarko contended was in place, and that Anadarko had no information that Cabot's Turkey Creek plant would fail to resume accepting normal gas quantities from B1R. Whether Anadarko acted in good faith and diligently by waiting for the anticipated resumption of processing by the Turkey Creek Plant instead of undertaking to re-work the Panhandle 10-inch pipeline to circumvent Cabot's Turkey Creek Plant with gas from 1-102 during its controversy with Cabot over whether a contract existed for Cabot to take gas from 1-102 and other Brown Dolomite wells, was for the trial court to determine from the evidence.")

86. *Id.* at 318.

Krabbe also contended that due diligence required the lessee to take action by bypassing the Turkey Creek Plant and connecting to another transmission line.⁸⁷ As authority for Krabbe's position, it was contended that *Gulf Oil Corp. v. Reid*⁸⁸ stands for the proposition that a "reasonable time" for a lessee to obtain resumption of production following a temporary cessation is the time it would take to lay gathering lines to a market. The court rejected this argument by noting that *Reid* was construing the effect of a shut-in royalty clause.⁸⁹ The trial court was free to consider all the evidence before it, and "the evidence was legally and factually sufficient to support the trial court's findings and conclusion that Anadarko diligently and in good faith sought to re-establish production."⁹⁰

Finally, Krabbe contended "that both the pricing dispute and the Turkey Creek Plant shut downs were foreseeable, avoidable, non-physical, marketing problems excluded from the temporary cessation of production doctrine."⁹¹ The court concluded that foreseeability and avoidability are not elements of the temporary cessation doctrine.⁹²

In summary, it appears that the court concluded that the specific cause of a cessation in production is not important, so long as the lessee acted in good faith. The more relevant inquiries are whether the cessation was temporary and whether the lessee acted with due diligence to restore production. If the cessation is temporary, and the lessee acts in good faith and with due diligence to restore production, then the interests of lessor and lessee are aligned. It is then logical to imply such a temporary cessation of production clause on behalf of the parties to the lease.

*Ridenour v. Herrington*⁹³ is a lease termination case holding that a lease terminates as a matter of law when there is a total cessation of production for six months and the lease has a sixty-day continuous operations clause. The lease expressly provided: "Cessation of paying production after the primary term for a period of sixty days shall cause this lease to terminate."⁹⁴ It was uncontroverted that production totally ceased for six months.⁹⁵ The court held that the express lease clause precluded implying a temporary cessation of production clause for a "reasonable time," and that, when there has been a complete cessation of production, there is no inquiry into the "reasonable period of time" over which to measure profitability or whether production is in "paying quantities."⁹⁶

87. *Id.* at 314.

88. 337 S.W.2d 267, 270 (Tex. 1960).

89. *Krabbe*, 46 S.W.3d at 318.

90. *Id.*

91. *Id.* at 314.

92. *Id.* at 319.

93. 47 S.W.3d 117 (Tex. App.—Waco 2001, pet. denied).

94. *Id.* at 119.

95. *See id.* at 122.

96. *Id.* at 121-22.

*Guinn Investments, Inc. v. Ridge Oil Co.*⁹⁷ holds that the temporary cessation of production doctrine does not apply to continue the lease when the lessee voluntarily ceases production or operations. Two separate but contiguous tracts were included in a single lease in 1937. The lessees, Guinn and Ridge, separately developed their tracts. In 1950, all production on the Guinn tract ceased, but the entire lease was held by production from two producing wells on the Ridge tract. In September 1997, Ridge tried to buy out Guinn, but was rebuffed. On December 1, 1997, Ridge turned off the electricity to its own wells. On January 13, 1998, Ridge wrote to the lessors explaining his intent to cease production for ninety days and requesting new leases. Ridge did get new leases, and on March 3, 1998, Ridge resumed production.⁹⁸

Guinn filed suit for declaratory judgment that the lease had not terminated. The lease apparently did not have an express continuous operations clause, and the court followed established case law in reading into the lease an implied temporary cessation of production clause.⁹⁹

To prevent the termination of a lease under an implied temporary cessation clause the cessation of production must be “due to sudden stoppage of the well or some mechanical breakdown of the equipment used in connection therewith, or the like,” and the lessee must remedy the problem and resume production within a “reasonable time.”¹⁰⁰

Although only six weeks elapsed between the shutting off of the electricity and Ridge’s approach to the lessors, the court concluded that the lease had already terminated. Because the lease had already terminated, the court refused to consider Guinn’s alleged tortious interference claim.¹⁰¹

B. POOLING CLAUSE

*Browning Oil Co., Inc. v. Luecke*¹⁰² holds that damages resulting from horizontal wells drilled in violation of the lease pooling clause are limited to royalties on the production that can be attributed with reasonable probability to the wrongfully pooled tract. Luecke, as lessor, executed three oil and gas leases with Browning covering three separate tracts. The operative provisions in the leases were the same. Each included detailed pooling provisions granting to lessee the right to pool, but subject to specific limitations.¹⁰³ The limitations included: an obligation to account based on surface acreage contributions to the unit; a requirement

97. *Guinn Investments, Inc. v. Ridge Oil Co.*, slip op., No. 2-00-055-CV, 2001 WL 253430 (Tex. App.—Fort Worth Mar. 15, 2001, no pet.).

98. *Id.* at *1.

99. *Id.* at *3 (citing *Midwest Oil Corp. v. Winsauer*, 323 S.W.2d 944, 946 (Tex. 1959)).

100. *Guinn*, 2001 WL 253430, at *3 (quoting *Watson v. Rochmill*, 155 S.W.2d 783, 784 (Tex. 1941)).

101. *Guinn*, 2001 WL 253430, at *6.

102. 38 S.W.3d 625 (Tex. App.—Austin 2000, pet. denied).

103. *Id.* at 636.

that a unit well drilled on the leasehold must include at least 60% of the unit acreage from the Luecke lease; an alternate requirement that if the unit was too large for the covered tract to equal 60%, then the unit must be filled out with other Luecke land; another requirement that non-Luecke land could be included only to satisfy Railroad Commission field rules; and a final requirement that only the minimum size units permitted by the Railroad Commission were permitted by the lease.¹⁰⁴ The leases were silent as to any distinction between vertical or horizontal wells. Luecke rejected a proposed lease amendment that would have expressly addressed the issues raised by a horizontal well.¹⁰⁵

Browning drilled and completed the Medusa #1 as a horizontal well that crossed seven tracts, including Luecke's tract two. The vertical portion of the well and a part of the horizontal drainhole were on Luecke's tract two. Browning drilled and completed the Weyand-Hays #1 as a horizontal well that crossed Luecke's tract one and tract three, but the vertical portion of the well was located on non-Luecke land. Each well was purportedly pooled in a unit that clearly did not conform to the pooling limitations in the Luecke leases.¹⁰⁶

The trial court determined that the poolings breached the pooling provisions in the Luecke leases, and that decision was affirmed.¹⁰⁷ The various anti-dilution provisions in the pooling clause were held to be equally applicable to horizontal wells.¹⁰⁸ In summary, the lessee was bound by the limitations in the leases and could not pool beyond the authority expressed in the leases.¹⁰⁹

The trial court submitted the question of damages to the jury. Based on the jury's verdict, the trial court awarded Luecke \$833,256, plus pre- and post-judgment interest and attorneys' fees.¹¹⁰ Luecke claimed that lessors were entitled to royalty on *all* production from the two purportedly pooled units. Furthermore, because the Weyand-Hays #1 crossed two separate tracts of Luecke's land, Luecke argued that the lessor was entitled to a *double* full royalty for the total production from that well, or a total of \$1,283,242.¹¹¹ Browning presented expert testimony that the royalty payable on the production actually attributable to the Luecke land was \$202,421, or less than the Luecke share of the pooled units, if Luecke had ratified the units.¹¹² The principal issue on appeal was the proper measure of damages.

Under the Texas rule of capture, a landowner owns all the oil and gas produced by a well drilled on the landowner's land. The landowner may

104. *Id.* at 637-38.

105. *Id.* at 638.

106. *See id.* at 638, 640.

107. *Browning*, 38 S.W.3d at 642.

108. *Id.* at 640.

109. *Id.* at 641-42.

110. *Id.* at 632.

111. *Id.* at 639.

112. *Browning*, 38 S.W.3d at 639.

produce whatever flows from that well, even if the oil and gas may have migrated from a neighboring tract. The neighboring landowner's only recourse is to drill his own well to capture whatever he can from his well.¹¹³ Pooling results in a cross-conveyance of interests in land by agreement, so that each landowner obtains an undivided joint ownership in the royalty earned from the land in the pooled unit. Pooling abrogates the rule of capture, but a "lessee's authority to pool is derived solely from the terms of the lease," and "a lessee has no power to pool absent this express authority."¹¹⁴

The court found that because Luecke was not validly pooled, Luecke was not entitled to any royalties on oil and gas produced from unit lands not owned by Luecke.¹¹⁵ Under the rule of capture, a vertical well may drain oil or gas from adjacent property, but the production will be treated as if it all were produced from the wellsite tract. Although the court recognized that lessees should not be allowed to ignore lease provisions and exceed their pooling authority with impunity, on public policy grounds the court held:

We decline to apply legal principles appropriate to vertical wells that are so blatantly inappropriate to horizontal wells and would discourage the use of this promising technology. The better remedy is to allow the offended lessors to recover royalties as specified in the lease, compelling a determination of what production can be attributed to their tracts with reasonable probability The Lueckes are entitled to the royalties for which they contracted, no more and no less.¹¹⁶

The court remanded on damages, but in a footnote¹¹⁷ acknowledged that Luecke might expand the remedies claimed on remand. The case before the court had been limited by Luecke's own claim that the only damages sought were those based on the royalties due under the lease. Presumably this leaves the door open for damages in tort, including the possibility of exemplary damages.

*Freeman v. Samedan Oil Corp.*¹¹⁸ holds that a common lease pooling clause may not be extended or construed to include the authority to unitize the lease acreage into a large waterflood unit. The twenty-five acre Freeman Lease covering an undivided 1/10 mineral interest was granted on June 28, 1966. On July 15, 1966, a producing oil well was completed on the duly formed Price Oil Unit, which included 19.83 acres from the Freeman Lease. The Price Oil Well was a unit well, but not a lease well. In early 1967, the lessee sought agreement from Freeman for a much wider secondary recovery unit. Freeman refused. The waterflood was

113. *See id.* at 633.

114. *Browning*, 38 S.W.3d at 634 (citing *Southeastern Pipe Line Co. v. Tichacek*, 997 S.W.2d 166, 170 (Tex. 1999)); *Jones v. Killingsworth*, 403 S.W.2d 325, 328 (Tex. 1965).

115. *Browning*, 38 S.W.3d at 643.

116. *Id.* at 647 (internal citation omitted).

117. *Id.* at n.30.

118. *Freeman v. Samedan Oil Corp.*, slip op., No. 2-00-055-CV, 2000 WL 33279603 (Tex. App.—Tyler Apr. 18, 2001, no pet.).

nevertheless put in place, and on September 1, 1967, the Price Oil Well was converted into the primary water injection well for the project. The Price Oil Well did not produce oil after September 1, 1967. In 1986, the Freeman Lease was included in a 764.25-acre gas unit and a new well, the Price Gas Well, was completed directly on the Freeman Lease. The waterflood was abandoned in 1990. Freeman sued for declaratory judgment that the Freeman Lease terminated in 1967 (sixty days after the Price Oil Well was converted into an injection well) and for a 1/10 interest in the Price Gas Well.¹¹⁹

The Freeman Lease pooling clause was a common form of pooling clause authorizing pooled units for oil up to 40 acres and for gas up to 640 acres, plus a tolerance of 10%.¹²⁰ The court refused to imply the authority to form a waterflood unit from this common clause based on the plain meaning of the pooling clause,¹²¹ the Railroad Commission order on the Waterflood Unitization Agreement (which expressly stated that it would not bind interest owners who did not execute the agreement),¹²² and statutory limits on the authority of the Railroad Commission to modify the contractual rights expressed in the lease.¹²³

Samedan raised the affirmative defenses of laches, estoppel, and waiver, but the court summarily dismissed them by citing to those cases which hold that revivor does not apply in lease termination cases.¹²⁴ There is no discussion of those cases which have found a revivor of a terminated lease.

*MCEN 1996 Partnership v. Glassell*¹²⁵ holds that the right to partition may be waived by executing a designation of unit. The opinion considered seven gas units, each created by a separate document.¹²⁶ The opinion loosely uses the terms "unitized," "pooling agreement" and "designation of unit," but it appears that the operative document as to at least some of the units may have been only a designation of unit.¹²⁷ In any event, the court analyzes the documents (pooling agreement? unitization agreement? designation of unit?) without making any distinction as to the type of document in its analysis.

The court first determined that the "pooled" mineral interests were an interest in real property and that a joint owner of an interest in real prop-

119. *Id.* at *1-3.

120. *Id.* at *5.

121. *Id.* at *6.

122. *Id.*

123. *Freeman*, 2000 WL 33279603, at *7 n.8 (citing TEX. NAT. RES. CODE ANN. § 101.012 (Vernon 1993) providing that "[a]greements for pooled units and cooperative facilities do not bind a landowner, royalty owner, lessor, lessee, overriding royalty owner, or any other person who does not execute them. The agreements bind only the persons who execute them No person shall be compelled or required to enter into such an agreement.").

124. *Freeman*, 2000 WL 33279603, at *9-10.

125. 42 S.W.3d 262 (Tex. App.—Corpus Christi 2001, pet. denied).

126. *Id.* at 263.

127. *See id.* at 263-64.

erty may compel partition.¹²⁸ However, parties can agree to waive the right to partition, and the court found a waiver in the language used in each pooling document. Three of the agreements included language that the unit would continue for as long as the pooled mineral was produced.¹²⁹ Two of the designations included language that the unit would continue for so long as a well was located on the pooled area capable of producing.¹³⁰ Two of the designations included language (very common in a typical designation of unit) that the leases were pooled in accordance with their terms.¹³¹ The court found a waiver of the right to partition in each agreement/designation for the term specified in the agreement/designation. The last form construed had no express term for the duration of the unit, but the court nevertheless construed the designation as an agreement to maintain the unit as a whole while the underlying leases were in effect.¹³²

The opinion does not mention any applicable operating agreement in its analysis of waiver. Typical form operating agreements contain express waivers of the right to partition and also contain a maintenance of uniform interest provision. These common provisions ordinarily preclude any attempt to partition oil and gas properties subject to an operating agreement, which would include most producing properties. In passing, the court notes that in the trial court it was alleged that the operating agreements contained a waiver, but the court then inexplicably fails to address what must have been an express waiver.¹³³

C. ROYALTY CLAUSE

*In re Tri-Union Development Corp.*¹³⁴ holds that Texas royalty owners are secured parties under U.C.C. § 9.319, so that a Chapter 11 Debtor is authorized to pay the pre-petition royalties (before the proposal and confirmation of the plan of reorganization) from cash collateral that the Debtor was statutorily required to segregate for the benefit of royalty owners. The Debtor operated oil and gas wells in several states, including Texas. Unpaid pre-petition royalties included checks which had not been cashed and checks which were in process at the time of the filing.¹³⁵ The Texas version of the U.C.C. includes a non-standard § 9.319 which provides for: "a security interest in favor of interest owners (as secured parties) to secure the obligations of the first purchaser of oil and gas production (as debtor) to pay the purchase price."¹³⁶

128. *Id.*

129. *Id.* at 264.

130. *Glassell*, 42 S.W.3d at 264.

131. *Id.*

132. *Id.* at 265.

133. *See id.*

134. 253 B.R. 808 (Bankr. S.D. Tex. 2000).

135. *Id.* at 810.

136. *Id.* at 811 (quoting TEX. BUS. & COM. CODE § 9.319 (Vernon 1991)).

The issues presented were whether the Debtor qualified as a first purchaser, and if so, whether the statute covered royalty owners who are paid money as well as those who were paid in kind. The Creditors Committee argued that the application of § 9.319 should be limited to royalty owners who take in kind, which would exclude most of the royalty owners.¹³⁷

The evidence showed that the Debtor received payment under 100% division orders, so that these royalty owners represented exactly the class of owners the statute was designed to protect.¹³⁸ The court was also influenced by the 1987 amendments to the Texas U.C.C. that were specifically intended to benefit these royalty owners.¹³⁹ The Debtor was therefore a first purchaser within the meaning of the statute, and all royalty owners, whether taking in kind or in funds, enjoyed the protection of a lien in production or proceeds.¹⁴⁰

In the absence of a statute such as § 9.319, the breach of contract or tort cause of action of an unpaid royalty owner would become a general unsecured claim in the bankruptcy of an operator or oil and gas purchaser.¹⁴¹ Under § 9.319, the liens of the royalty interest owners in the production or its cash or account proceeds were perfected and enforceable as of the date of filing and were not susceptible to being cut off by a *bona fide* purchaser under state law or under 11 U.S.C. § 545 of the Bankruptcy Code.¹⁴²

Union Pacific Resources includes three published opinions on the same case. The principal issue is class certification. In *Union Pacific Resources Group, Inc. v. Hankins*,¹⁴³ the royalty owners were certified as a class by the trial court. Plaintiffs sued Union Pacific Resources Group, Inc. (UPRG) alleging breach of the implied covenant to manage and administer the leases, failure to obtain the best current market price for the gas, failure to pay royalties based on the true market price, unjust enrichment, and requesting an accounting and injunctive relief. Plaintiffs sought to certify a class of royalty owners owning an interest in Crockett County, whose leases were owned or operated by UPRG, and whose gas was purchased by an affiliate of UPRG. Excluded from the class were those royalty owners whose leases allowed affiliate transactions or index pricing and those royalty owners already pursuing separate litigation.¹⁴⁴ In this interlocutory appeal of the order certifying the class, the court abated the appeal and remanded the case to the trial court for additions to the record.¹⁴⁵

137. See *In re Tri-Union*, 253 B.R. at 811.

138. *Id.* at 812.

139. See *id.*

140. *Id.*

141. *Id.* at 811.

142. *In re Tri-Union*, 253 B.R. at 814.

143. 41 S.W.3d 286 (Tex. App.—El Paso 2001, no pet.).

144. *Id.* at 287.

145. *Id.* at 289.

The court acknowledged that its review was to be conducted under an abuse of discretion standard¹⁴⁶ and recognized the general requirements for certification set forth in Rule 42¹⁴⁷ and in *Bernal*.¹⁴⁸ Those requirements are generally summarized as (1) numerosity [many possible plaintiffs in class], (2) commonality [questions of law or fact are common to the class], (3) typicality [representative parties have typical claims or defenses], and (4) adequacy of representation [representatives will fairly and adequately protect the interests of the class].¹⁴⁹ The court remanded, because the trial court's order did not meet the requirement set forth in *Bernal* that the order of certification must indicate how the claims will likely be tried.¹⁵⁰

In the second opinion, *Union Pacific Resources Group, Inc. v. Hankins*,¹⁵¹ the court denied a hearing on UPRG's request for hearing on UPRG's motion to reconsider class certification. In response to the remand from the first appeal, the trial court issued an order supplementing the class certification order, an order to supplement the record, and an order denying UPRG's request for a hearing. The court held that the court's orders were not subject to an interlocutory appeal.¹⁵²

In the third reported opinion, *Union Pacific Res. Group, Inc. v. Hankins*,¹⁵³ the court conducted a *Bernal* review and affirmed the trial court's certification of the class. The trial court certified the class as:

All individuals and entities who:

- a. Own or owned royalty under leases from which gas is produced, where
- b. The leases were owned and/or operated by the Defendant Union Pacific Resources Group and/or an affiliate of Union Pacific Resources Group, and
- c. The leases are located in Crockett County, Texas; and
- d. The gas was purchased by Defendant Union Pacific Fuels and/or another affiliate of Union Pacific Resources Group.¹⁵⁴

The class, the excluded members, and the class representatives were all the same as in the first appeal. Additional facts noted included that UPRG had an interest in 590 oil and gas leases, on 122 unique lease forms, with 58 different types of royalty clauses. There are thirteen different gathering systems utilizing various price indexes to determine well-head value.¹⁵⁵ Numerosity is not discussed in the opinion.

However, UPRG did complain that it would be deprived of the right to

146. *Id.* at 288.

147. *Id.*; see also TEX. R. CIV. P. § 42.

148. *Hankins*, 41 S.W.3d at 288-89 (citing *Southwestern Refining Co., Inc. v. Bernal*, 22 S.W.3d 425, 433 (Tex. 2000)).

149. *Hankins*, 41 S.W.3d at 288.

150. *Id.* at 289.

151. 51 S.W.3d 738 (Tex. App.—El Paso 2001, no pet.).

152. *Id.* at 740.

153. 51 S.W.3d 741 (Tex. App.—El Paso 2001, no pet. h.).

154. *Id.* at 747.

155. *Id.*

develop and present its defenses and variant facts to a jury.¹⁵⁶ The court held that UPRG had waived its position, but even if it had not, UPRG would have the opportunity to show in response to individual claims that a particular member was paid the correct amount.¹⁵⁷ It is unclear how that is supposed to be accomplished. The court refused to directly consider *Yzaguirre v. KCS Res., Inc.*,¹⁵⁸ because it considered the application of *Yzaguirre* to be an issue on the merits. However, if *Yzaguirre* means that individual leases must be examined to determine if there is an implied covenant, then there are possibly 590 (or at least 122) reasons why there is no commonality or typicality in this class.

In discussing commonality, the court concludes that UPRG's conduct, its transactions with affiliates, and the resulting diminishment of royalties all supply the element of commonality. The court assumes the issue of whether UPRG breached the covenant to market would apply equally and seems to generally ignore the effect of *Yzaguirre*.¹⁵⁹

On typicality, UPRG argued that the class representatives' royalty provisions were not typical as to many other royalty owners and that there were defenses applicable to the class representatives that were not applicable to other class members. The court rejected these arguments and found sufficient typicality based on the common issues of underpayment and breach of the (assumed) implied covenant to market.¹⁶⁰

UPRG challenged on adequacy of representation by raising conflicts of interest. UPRG contended that the differing royalty clauses would create conflicts requiring class counsel to pursue legal theories that would advance some class members' interest at the expense of other class members. The court concluded that the right to complain of this form of conflict belonged to class counsel's clients as an ethical issue, rather than an appellate issue.¹⁶¹

The court also considered the predominance requirement under Rule 42. The test is "whether common or individual issues will be the object of most of the efforts of the litigants and the court."¹⁶² The court concluded that the trial court had conducted the "rigorous analysis" required by *Bernal* and that the trial court had appropriately understood the claims, defenses, relevant facts, applicable substantive law, and considered the evidence in determining to certify the class.¹⁶³

Class certification is a particularly hot topic for litigators, but also for oil and gas lawyers, because many of the current cases are oil and gas cases. Issues that oil and gas practitioners face are perhaps more likely

156. *Id.* at 749-50.

157. *Id.* at 750.

158. 53 S.W.3d 368 (Tex. 2001) (holding market value lease payments may be calculated on an amount less than the amount actually received by lessee) [reported in this Article].

159. See *Hankins*, 51 S.W.3d at 751.

160. *Id.* at 752.

161. *Id.* at 753.

162. *Id.* (quoting *Bernal*, 22 S.W.3d at 434).

163. *Hankins*, 51 S.W.3d at 753-54.

than others to end up in someone's class action because there are frequently many parties involved with relatively common issues. At press time, the action in the courts was intense.¹⁶⁴

D. MISCELLANEOUS

*Edwards v. Guy*¹⁶⁵ holds that when title to an oil and gas lease is taken in the name of someone other than the party who advances the purchase price, a resulting trust is created in favor of the actual purchaser. Edwards purchased a lease in 1973 in the name of an entity he controlled on behalf of his investors, Guy and Weil and others. Edwards circulated a joint operating agreement (JOA) to all of the working interest owners. Because they objected to the risk penalty provisions, Guy and Weil refused to sign. The other working interest owners drilled a producing well. Guy and Weil never received anything, although the well reached payout, even with the risk penalty included. Edwards misrepresented to Guy and Weil that the lease had terminated and that a new lease had been obtained by another of Edwards' companies and that the successful well had been drilled by the second company. Edwards sold the 1973 lease to another party, and Guy and Weil sued Edwards for damages.¹⁶⁶

Edwards claimed that he did not commit fraud, because Guy and Weil could not produce an assignment that would satisfy the statute of frauds.¹⁶⁷ His contention was that any representation made by him to Guy and Weil was irrelevant because they owned no interest in the 1973 lease.¹⁶⁸ There was no written agreement that Edwards' company held title as trustee for Guy and Weil, but there was extensive evidence that Guy and Weil owned the interest they claimed. The court rejected Edwards' claim and held that when a property is taken in the name of someone other than the person who advances the purchase price, a resulting trust is created, and a resulting trust is not subject to the statute of frauds.¹⁶⁹

Edwards also contended that the injury complained of resulted from the failure of Guy and Weil to sign the JOA, not his alleged misrepresentation. The court held:

164. See e.g., *Wagner & Brown v. Horwood*, 53 S.W.3d 347 (Tex. 2001) (dissenting vigorously against the court's refusal to grant review in an oil and gas class certification appeal when the appellate courts are clearly in conflict on certification issues); see also *Phillips Petroleum Co. v. Bowden*, No. 14-00-01184-CV, 2001 WL 1249995, at *5 n.6 (Tex. App.—Houston [14th Dist.] Oct. 18, 2001, no pet. h.) (not designated for publication) (distinguishing *Hankins*, 51 S.W.3d 741, specifically because the court failed to separate market value owners and proceeds owners which the court found compelling on the issue of typicality); *Union Pacific Res. Group, Inc. v. Neinast*, 67 S.W.3d 275, 283 (Tex. App.—Houston [1st Dist.] 2001, no pet.) (expressly refusing to follow *Hankins* because it does not consider *Yzaguirre*).

165. No. 01-99-00191-CV, 2000 WL 1538506 (Tex. App.—Houston [1st Dist.] Oct. 19, 2000, pet. denied) (not designated for publication).

166. *Id.* at *1.

167. *Id.* at *2 (citing TEX. BUS. & COM. CODE ANN. § 26.01 (Vernon 1987)).

168. *Id.* at *2.

169. *Id.* at *3.

A JOA is a management contract; it does not affect the ownership interest an individual has in an oil and gas lease (recognizing a JOA is a contract, and that when an individual chooses not to execute a JOA, they do not lose their interest in the lease; however, they do not get to participate in the proceeds from a productive well until the costs and a penalty are recovered by those choosing to participate in the JOA).¹⁷⁰

IV. SEISMIC

*Encina Partnership v. COREnergy, L.L.C.*¹⁷¹ is one of the very few reported cases construing the common practice of utilizing bank drafts to close on leasing and seismic permit transactions. *Encina* holds that the common provision in a draft making payment on the seismic permit subject to approval within a specified time is a condition precedent to the formation of a contract.¹⁷²

COREnergy employed a landman to obtain seismic permits in an area which COREnergy believed to be prospective for oil and gas. The landman obtained a seismic permit from a 1/8 mineral interest owner in the Encina Ranch (which included 4,272 acres) at forty-five dollars an acre, for a total of \$192,240.¹⁷³ Although the opinion does not explain, this is such a large payment for a 1/8 interest that it is possible the landman failed to proportionately reduce the payment.

The bank draft provided “[o]n approval of seismic permit or lease described hereon and on approval of title to same by drawee not later than 3 days after the arrival of this draft at collecting bank.”¹⁷⁴ COREnergy timely dishonored the draft. The *Encina* case involved a seismic permit, but the court relied heavily on a similar case involving a lease. In *Sun Exploration and Prod. Co. v. Benton*,¹⁷⁵ the Texas Supreme Court construed a provision on Sun’s bank draft reading “15 days after sight and upon approval of title.” The *Sun Exploration* court held that this language constituted a condition precedent to Sun’s liability on the draft.¹⁷⁶ The Supreme Court held:

A contemporaneously exchanged draft and deed must be construed together. Here, the language on the face of the draft made Sun’s approval of title a condition precedent to formation of the contract. Where the grantee imposes certain conditions precedent to acceptance, title does not pass under the deed until fulfillment of such conditions. The draft effectively protected Sun against paying for the property if it disapproved the title.¹⁷⁷

170. *Edwards*, 2000 WL 1538506, at *5 (citing *Hill v. Heritage Res., Inc.*, 964 S.W.2d 89, 100-11 (Tex. App.—El Paso 1997, pet. denied)).

171. 50 S.W.3d 66 (Tex. App.—Corpus Christi 2001, pet. denied).

172. *Id.* at 69.

173. *Id.* at 67.

174. *Id.* at 69.

175. 728 S.W.2d 35 (Tex. 1987).

176. *Id.* at 37.

177. *Id.*

The *Encina* court found the *Sun Exploration* case to be controlling, even though the condition upon which the draft was dishonored was not title, because COREnergy simply refused to approve the permit, and even though the document subject to the draft was not a lease, but a seismic permit.¹⁷⁸

V. OPERATING AGREEMENTS

*Stable Energy, L.P. v. Kachina Oil & Gas, Inc.*¹⁷⁹ considers the change of operator and nonconsent provisions of a joint operating agreement (JOA). Kachina, as operator, proposed an acid workover with a supporting authorization for expenditure (AFE). Stable, the owner of a 33% interest, consented. Approximately 28% of the owners went non-consent.¹⁸⁰ Article VI.B.2 of the JOA provided:

*Upon commencement of operations for the . . . reworking . . . of any such well by Consenting Parties . . . each Non-Consenting Party shall be deemed to have relinquished to Consenting Parties . . . all of such Non-Consenting Party's interest in the well and share of production therefrom.*¹⁸¹

Stable sent Kachina a check for the share of the workover costs attributable to the non-consenting owners. However, Stable and Kachina were in a dispute regarding operation of the well and Stable's past due joint interest billings. Kachina escrowed Stable's check. Stable claimed it was the operator and would take control of the well. Stable's affiliate, Anchor Operating Company, cut the locks from the gate, took possession of the well, and for several weeks conducted an acid workover. Kachina withdrew its AFE.¹⁸²

The JOA change-of-operator provision required that the new operator must have an interest and must be selected by majority vote. Stable contended that it became the majority owner when it transferred the funds to Kachina for the 28% non-consent interest. The court rejected this argument and held that under the JOA, the transfer of those interests could have occurred only upon the "commencement of operations" as to the project proposed by Kachina. Kachina withdrew the AFE on that project.¹⁸³

Stable argued that the project began when Anchor seized the well and started the acid workover. The court reasoned that this could be true only if "(1) the operations performed were the *same* as those described in the AFE, and (2) the operations were performed by a duly elected operator."¹⁸⁴ The court found that the operation proposed and the operation performed were not the same and rejected Stable's argument that the

178. *Encina P'ship*, 50 S.W.3d at 69.

179. 52 S.W.3d 327 (Tex. App.—Austin 2001, no pet.).

180. *Id.* at 330.

181. *Id.* at 332.

182. *Id.* at 330.

183. *Id.* at 332.

184. *Stable Energy*, 52 S.W.3d at 332.

work performed need be only substantially similar to Kachina's proposal.¹⁸⁵ The court also held that Stable and Anchor together could not constitute a majority without the acquisition of the non-consent interests, and that could not possibly have occurred before operations commenced. Therefore, the proposed election of Anchor was ineffective.¹⁸⁶ Because the operations as proposed and as performed were substantially different, and because the operations were not conducted by the operator, the non-consent interests were never relinquished and could not have been acquired by Stable.¹⁸⁷ Finally, the court also denied Stable's claim for reimbursement of the workover costs. The court held that the JOA provides for reimbursement only to the operator.¹⁸⁸

VI. DRILLING CONTRACTS

*Wil-Roye Investment Co. II v. Alleder, Inc.*¹⁸⁹ holds a drilling contractor liable for damage to the well attributable to the contractor's own negligence and refuses to find that the operator assumed the risk of loss of circulation attributable to the contractor's own negligence. The driller sued for unpaid invoices, and the operator defended based on offset for damages suffered by the operator and attributable to the driller's negligence.¹⁹⁰ Paragraph 12.3 of the drilling contract contained an express provision that the operator assumed the risk of loss in the event of loss of circulation.¹⁹¹ Paragraph 18.6 provided:

Subject to the provisions of paragraphs 12 and 15 hereof should a fire or blowout occur or should the hole for any cause attributable to Contractor's operations be lost or damaged while Contractor is engaged in the performance of work hereunder on a footage basis, all such loss of or damage to the hole shall be borne by Contractor.¹⁹²

The evidence showed that the driller stopped the pipe during a loss of circulation and then made several mistakes in attempting to free the pipe which had become "hydrostatically stuck."¹⁹³ After a bench trial, the trial court found the cause of the damage was the negligence of the driller.¹⁹⁴

A contractual provision limiting liability for a party's own negligence must be conspicuous and must be expressed in specific terms.¹⁹⁵ The court found that this drilling contract had no such express or conspicuous language that would relieve the driller in advance for the driller's own

185. *Id.* at 332-33.

186. *Id.* at 334.

187. *Id.*

188. *Id.* at 335.

189. No. 08-00-00321-CV, 2001 WL 903179 (Tex. App.—El Paso Aug. 10, 2001, no pet.) (not designated for publication).

190. *Id.* at *1-2.

191. *Id.* at *3.

192. *Id.*

193. *Id.* at *1.

194. *Wil-Roye Inv.*, 2001 WL 903179, at *2.

195. *Id.* at *4.

negligence.¹⁹⁶ The court also rejected the driller's contention that the operator had expressly assumed the risk of loss of circulation, noting that such reasoning would render paragraph 18.6 meaningless.¹⁹⁷ Moreover, whether the loss was caused by loss of circulation or the driller's own negligence was a fact question, and that question had been determined against the driller.¹⁹⁸

VII. GAS CONTRACTS

*Aquila Southwest Pipeline, Inc. v. Harmony Exploration, Inc.*¹⁹⁹ holds that a gas purchaser under a gas purchase contract is obligated to exercise "best efforts" regarding the quantity of gas to be purchased under UCC § 2.306. Harmony was a small producer selling its gas to Aquila under a fairly typical arrangement whereby the producer sells its gas at the well-head to the purchaser, and the purchaser then gathers and processes the gas to extract the liquids. The purchaser then accounts to the producer on the basis of a percentage of the proceeds from the liquids, plus the sale of the residue gas at the tailgate of the plant.²⁰⁰ Until 1992, the plant was running at or near 90-95% efficiency and recovering over 90% of all casinghead liquids.

Aquila then began aggressively adding reserves to the system, so that the plant capacity was overwhelmed. Aquila used the emergency bypass line to bypass the plant. As much as 50% of the gas it received was not processed at the plant.²⁰¹ Aquila used the bypass line for at least two years while Aquila was adding even more volume on the system.²⁰²

By contract, Harmony was obligated to deliver 100% of its production to Aquila. Aquila's obligation to take was limited by Sections 5.2 and 5.5 of the contract, which provided:

5.2 . . . The parties expressly recognize that Buyer's obligations to take pursuant to the rules or otherwise shall be subject to the ability of Buyer's facilities to handle all gas connected thereto, lessening or fluctuating demand for gas on Buyer's or its resale purchaser's system, the location on Buyer's or its resale purchaser's system of gas supplies and demand, and any other valid reason such as force majeure, whether or not of a kind herein mentioned.

* * *

5.5 In the event any of Buyer's facilities are of insufficient capacity to handle all of the gas connected thereto, Buyer shall be obligated only to take gas ratably from all leases and/or wells delivering into such facilities.²⁰³

196. *Id.*

197. *Id.*

198. *Id.*

199. 48 S.W.3d 225 (Tex. App.—San Antonio 2001, pet. denied).

200. *See id.* at 231.

201. *Id.* at 237.

202. *Id.* at 238.

203. *Id.* at 231-32.

Harmony obtained a favorable jury verdict in response to the special issue: "Do you find from a preponderance of the evidence that Aquila did not use its best efforts to process Harmony's gas from the Harmony Wells?"²⁰⁴

Aquila is another in a series of gas contract cases in which the application of the "best efforts" requirement in UCC § 2.306 has been an issue. Section 2.306(b) provides:

A lawful agreement by either the seller or the buyer for exclusive dealing in the kind of goods concerned imposes unless otherwise agreed an obligation by the seller to use best efforts to supply the goods and by the buyer to use best efforts to promote their sale.²⁰⁵

Aquila is apparently the first reported decision imposing the "best efforts" requirement on the purchaser. In *Northern Natural Gas Co. v. Conoco, Inc.*,²⁰⁶ the Texas Supreme Court considered a group of contracts in which Northern agreed to supply gas for Conoco to process. The "best efforts" provision was held to be inapplicable in this processing-contract only case.²⁰⁷ In *Lenape Resources Corp. v. Tennessee Gas Pipeline Co.*,²⁰⁸ the Texas Supreme Court held that the "best efforts" gap-filler quantity provision was inapplicable to a take-or-pay contract because the quantity term (85% of deliverability) in that case was expressly provided in the contract.²⁰⁹

The *Aquila* court found that § 2.306(b) "permits the quantity term in an exclusive dealing contract to be measured in terms of 'best efforts,'"²¹⁰ and that "parties in an exclusive dealing contracts are bound to use reasonable diligence as well as good faith in their performance of the contract."²¹¹ Because the Harmony/Aquila contract assigned the exclusive right to process Harmony's gas to Aquila, and the parties did not agree in the contract to modify or waive the best efforts provision of § 2.306(b), that provision applies to the contract.²¹²

*Fortune Prod. Co. v. Conoco, Inc.*²¹³ is a gas processing case with additional issues related to gathering and accounting for field liquids. Defendant Conoco paid a premium to purchase the Concho Valley Gas System (gas purchase contracts, gathering system, gas processing plants, and residue gas contract), because the contract price for the residue gas was, at that time, well above the prevailing market price. Plaintiffs were producers of natural gas who were operating within the Concho Valley Gas System under existing gas processing contracts and arrangements for collecting and accounting for field liquids. Conoco bought the plants and

204. *Aquila*, 48 S.W.3d at 232.

205. TEX. BUS. & COM. CODE ANN. § 2.306 (Vernon 1994).

206. 986 S.W.2d 603 (Tex. 1998).

207. *Aquila*, 48 S.W.3d at 234 (citing *Northern Natural*, 986 S.W.2d at 607).

208. 925 S.W.2d 565 (Tex. 1996).

209. *Aquila*, 48 S.W.3d at 235 (citing *Lenape*, 925 S.W.2d at 570-71).

210. *Aquila*, 48 S.W.3d at 234.

211. *Id.*

212. *See id.* at 235.

213. 52 S.W.3d 671 (Tex. 2000).

contracts, terminated the old gas purchase contracts, and entered into new gas purchase contracts with lower prices payable to the producers. Conoco also ceased paying the gas producers for the field liquids it collected. The gas producers sued for fraud in the inducement on the new contracts and for damages for unjust enrichment on the field liquids.²¹⁴ The fraud claim was based on Conoco's misrepresentation to the producers that their gas would no longer be sold under the favorable residue gas contract and that Conoco had enough gas from other sources to supply the minimum take obligations under that contract.²¹⁵ In fact, most of the producers' residue gas continued to be sold under the same residue gas contract.²¹⁶

The jury found that Conoco had committed fraud and that fraud damages amounted to \$5,000,000. However, the jury also found that each plaintiff had ratified their contract with Conoco after discovering the fraud. The jury also found that Conoco had been unjustly enriched by almost \$900,000 when it failed to include field liquids in the payments to the plaintiff producers. Judgment was rendered for the unjust enrichment, but nothing for the fraud.²¹⁷

The court discussed at length whether the ratification of a contract induced by fraud precluded the right to sue for damages.²¹⁸ The court recognized that there may be circumstances under which a party who was induced to enter a contract by fraud may ratify that contract in such a manner that a claim for damages is foreclosed. The court found in this case that the ratification by the producers who continued to sell to Conoco without a written contract precluded a suit for damages, but the ratification by the producers who continued to sell to Conoco under their new written contract did not preclude a suit for damages.²¹⁹ The plaintiff producers selling without written contracts delivered their gas and accepted payment. There was no requirement upon them to sell, nor upon Conoco to purchase. As to those producers without written contracts who continued their deliveries to Conoco after learning of Conoco's misrepresentation, delivering and accepting goods with knowledge that they are offered at a certain price indicates a promise to pay and an agreement to accept that price.²²⁰ The limited acts of the producers selling under the new written contracts did not, as a matter of law, foreclose their right to sue for fraud damages.²²¹ There was apparently a merger clause in the written contracts, but because Conoco failed to assert that argument in the trial court, the issue was not preserved on appeal.²²²

214. *Id.* at 674-75.

215. *Id.* at 674.

216. *Id.* at 675.

217. *Id.*

218. *Fortune Prod.*, 52 S.W.3d at 676-79.

219. *Id.* at 676.

220. *Id.* at 680 (citing 2 Williston, A Treatise on the Law of Contracts § 6:42 at 446 (R. Lord ed., 4th ed. 1991)).

221. *Fortune Prod.*, 52 S.W.3d at 679.

222. *See id.* at 681.

The second major issue in the case was the measure of damages for Conoco's fraud. Fraud damages were submitted to the jury based on a benefit-of-the-bargain measure of damages. The jury calculated damages as if the producers could have negotiated a price based entirely on the residue gas contract, rather than on the spot market. The court concluded that there was no evidence to support that measure of damages, although there was some evidence that a part (perhaps 10%) of the production could have been sold on the basis of a price tied to the residue gas contract. The court remanded on damages for fraud.²²³

Under the written contracts, Conoco took title to the entire gas stream at a point upstream of the point where the field liquids or condensate were taken out of the gas stream. Plaintiffs initially sought to recover under a theory of conversion, but after a directed verdict against them, the trial court permitted an amendment to the petition to assert that Conoco had been unjustly enriched. Conoco raised as an affirmative defense the express contract governing the subject matter of the dispute, which would preclude a recovery in equity for unjust enrichment.²²⁴ Conoco did not submit an issue to secure a finding that an express contract existed covering the subject matter of the dispute. The court found that such a submission was not necessary as to the claims raised by the plaintiff producers selling their gas under written contracts because those contracts were in evidence and unambiguous.²²⁵ The plaintiff producers selling under written contracts could not recover under a theory of unjust enrichment. However, as to those parties selling to Conoco without a written contract, Conoco failed to establish its defense by failing to submit the defensive issue.²²⁶ The judgment for unjust enrichment damages on the field liquids was reversed and rendered as to the producers with written contracts, affirmed as to one producer with no written contract, and remanded as to another producer who had a written contract part of the time and no written contract part of the time.²²⁷

*Redman Energy Corp. v. Koch Midstream Services Co.*²²⁸ holds that a gas processor's "economic out" clause extended to and included the economics of replacing a gathering line from the well to the plant. The gas processing contract required the processor to take possession of the gas at the delivery point (the wellhead), gather the gas to the plant, and return the processed gas to the producer at the tailgate of the plant.²²⁹ The contract specifically required the processor to construct the necessary gathering lines.²³⁰ The gathering line in question failed, and the processor invoked the economic out clause, which provided:

223. *Id.* at 681-82.

224. *Id.* at 683.

225. *Id.*

226. *Fortune Prod.*, 52 S.W.3d at 685.

227. *Id.*

228. 45 S.W.3d 341 (Tex. App.—Texarkana 2001, no pet.).

229. *Id.* at 346.

230. *Id.*

In the event Gas from the lease as described in Exhibit "A" attached hereto is or becomes insufficient in volume or liquefiable hydrocarbon content, *or becomes uneconomical for processing*, then Processor reserves the right to submit to Producer an alternate processing proposal.²³¹

The producer contended that for this clause to be triggered, the act of processing itself must become costly without reference to the act of gathering.²³² In addition, the producer contended that there must be some change in the gas itself in order to invoke this clause because the processor should have anticipated the costs of maintaining the pipeline.²³³ The court rejected the producer's argument, and, from a "four corners" analysis of the gas processing contract, concluded that the contract did not treat gathering and processing as separate acts; but rather, the gathering was an integral part of the processing of the gas.²³⁴

VIII. PIPELINES

Exxon Pipeline Co. v. Zwahr,²³⁵ places an extraordinarily high value on the condemnation of a small pipeline easement by valuing the land not for its use as a cotton field, but for its use as a pipeline easement. There was an existing pipeline easement in favor of Koch across the Zwahr land. Exxon condemned a 1.01 acre tract on the Zwahr land for a pipeline easement that overlapped the Koch easement by approximately 82%. Zwahr continued to grow cotton on the easement. As farmland, the acreage condemned was worth only a few thousand dollars. Judgment was entered for \$30,000, as the fair market value of the 1.01-acre easement, and \$10,000 as the fair market value of Exxon's right to assign the easement.²³⁶

The critical issue in the case was the highest and best use of the property taken. The court was persuaded to value the property for its use as a pipeline easement because there was an existing pipeline corridor (the Koch easement), the pipeline corridor had been in place for a long time, Exxon's pipeline was buried entirely within the existing easement, and Exxon's own engineer testified that Exxon preferred to lay new lines next to existing ones.²³⁷ Although there are many factors that are considered in determining the site for a pipeline, one of the reasons for co-locating pipelines is to accommodate the landowners by confining all pipelines to a small area. This case would suggest that by attempting to reduce interference with other concurrent owners and uses of the property, a pipeline company may subject itself to damages thirty times larger than would otherwise be imposed.

231. *Id.* at 343 (emphasis added).

232. *Id.* at 345.

233. *Redman Energy*, 45 S.W.3d at 344.

234. *Id.* at 346.

235. 35 S.W.3d 705 (Tex. App.—Houston [1st Dist.] 2000, pet. granted).

236. *Id.* at 708.

237. *Id.* at 711.

IX. RAILROAD COMMISSION

*In re Apache Corp.*²³⁸ holds that the Texas Railroad Commission does not have exclusive jurisdiction over disputes concerning the abatement of water contamination caused by oil and gas production and the doctrine of primary jurisdiction will not preclude the prosecution of a civil suit for abatement and damages.²³⁹ The landowner, Marion, believed that Apache's wells had contaminated two aquifers underlying his property, which resulted in the destruction of his crops. Marion complained to the Railroad Commission which began proceedings.²⁴⁰ Marion also filed suit in state court alleging trespass, negligence, negligence *per se*, nuisance, infliction of emotional distress, and strict liability. Marion sought to abate the contamination and to recover damages.²⁴¹

Apache sought to abate the state court proceeding pending the resolution of the Railroad Commission proceeding. Apache contended that the Railroad Commission had exclusive or primary jurisdiction. By statute, the Railroad Commission has the authority "to 'adopt and enforce rules and orders' to prevent the pollution of surface and subsurface water."²⁴² Also by statute, the Railroad Commission "is *solely responsible* for the control and disposition of waste and the abatement and prevention of pollution of surface and subsurface water resulting from . . . activities associated with the drilling, development, and production of oil or gas" ²⁴³ The court held that these provisions did not confer exclusive jurisdiction on the Railroad Commission, but rather evidenced the legislature's intent to avoid conflicts between state agencies.²⁴⁴ In reaching its decision, the court relied heavily upon other statutes permitting landowners to immediately file and prosecute damage suits founded upon the violation of Railroad Commission rules and orders.²⁴⁵ The court placed particular emphasis on Tex. Nat. Res. Code Ann. § 85.322, which provides:

[n]one of the provisions of . . . chapter [8] . . . , no suit by or against the [TRC], and no penalties imposed on or claimed against any party violating a law, rule, or order of the [TRC] shall *impair or abridge or delay a cause of action for damages or other relief* that an owner of land . . . may have or assert against any party violating any rule or order of the [TRC] or any judgment under this chapter.²⁴⁶

The court also refused to abate the proceeding based on primary jurisdiction. It found that the suit fit within the well-established exception to

238. 61 S.W.3d 432 (Tex. App.—Amarillo, 2001, orig. proceeding [leave denied]).

239. *Id.* at 436-37.

240. *Id.* at 433.

241. *Id.*

242. *Id.* at 434 (quoting from TEX. NAT. RES. CODE ANN. § 91.101 (Vernon 1993)).

243. *In re Apache Corp.*, 61 S.W.3d at 434 (quoting from TEX. WATER CODE ANN. § 26.131(a) (Vernon 2000)).

244. *In re Apache Corp.*, 61 S.W.3d at 435.

245. *Id.* at 435-36 (quoting from TEX. NAT. RES. CODE ANN. §§ 85.321-.322, 91.003(a) (Vernon Supp. 2001)).

246. *In re Apache Corp.*, 61 S.W.3d at 435 (alterations in original).

primary jurisdiction, specifically, "actions or disputes which are inherently judicial in nature and over which the legislature has not vested exclusive jurisdiction in some administrative body, may proceed."²⁴⁷

*H.G. Sledge, Inc. v. Prospective Investment and Trading Co.*²⁴⁸ holds that an overriding royalty owner on an adjoining tract is not an "affected person" entitled to notice of hearing for a drilling permit under a Rule 37 exception.²⁴⁹ Rule 37 is a Railroad Commission rule pertaining to the spacing of wells that generally determines which drilling locations are legal without further hearing. Locations which do not fit within the rule require that an exception be granted after hearing.²⁵⁰

Sledge was the operator of both the drillsite tract and the offset tract.²⁵¹ The Prospective Investment and Trading Company, Ltd. (PITCO) owned an overriding royalty on the offset tract.²⁵² Sledge, as the applicant for a Rule 37 exception, was required to provide the Railroad Commission with a list of all "affected persons" who were entitled to receive notice of the Rule 37 application. Sledge did not notify PITCO, and as the operator of the offset tract, Sledge waived notice to itself.²⁵³

Under similar facts, the court had previously ruled that notice to royalty owners was not required in a Rule 37 proceeding.²⁵⁴ The notice provision, Rule 37(a)(2)(A), identifies the persons to whom notice must be given as including all "affected persons" within a certain distance from the proposed well location, "including" operators, lessees of record for tracts with no operator, and owners of unleased mineral interests.²⁵⁵ Although this list clearly does not include overriding royalty owners, the list is not exclusive.²⁵⁶ In ruling that overriding royalty owners were not included in "affected persons," the court relied upon its prior decisions as to royalty owners, the Commission's interpretation of its own rule, and the rule's history.²⁵⁷

The court rejected PITCO's argument that there was an inherent conflict of interest in Sledge's position as operator of both the wellsite tract and the offset tract and that only PITCO could properly inform the Commission of the facts relevant to determining the necessity of an exception. The court cited to a case that found that the commission does not have the authority to adjudicate questions of title or rights of possession.²⁵⁸ In

247. *Id.* at 436.

248. 36 S.W.3d 597 (Tex. App.—Austin 2000, pet. denied).

249. *Id.* at 599, 607.

250. See 16 TEX. ADMIN. CODE § 3.37 (2000).

251. *H.G. Sledge, Inc.*, 36 S.W.3d at 599.

252. *Id.*

253. *Id.* at 600.

254. *Shell Petroleum v. R.R. Comm'n*, 137 S.W.2d 797 (Tex. Civ. App.—Austin 1940, no writ); *Rabbit Creek Oil Co. v. Shell Petroleum Corp.*, 66 S.W.2d 737 (Tex. Civ. App.—Austin 1933, no writ).

255. *H.G. Sledge*, 36 S.W.3d at 603.

256. *Id.*

257. *Id.* at 604-06.

258. *Id.* at 606.

dicta, the court stated that PITCO's proper remedy was a suit for damages, either under the instrument creating the overriding royalty or under the farmout agreement under which Sledge claimed title.²⁵⁹

*Occidental Permian Ltd. v. Railroad Commission*²⁶⁰ holds that the reduced production tax on oil applicable to expanded enhanced recovery projects may be lost by failure to timely obtain Railroad Commission approval. The Texas Tax Code imposes a production tax on oil,²⁶¹ but "since 1991, oil produced from an expanded enhanced recovery project has been taxed at a significantly lower rate."²⁶² The lower tax rate is applicable "provided that 'before the expansion begins, the [C]ommission approves the expansion and designates the area to be affected by the expansion.'²⁶³ The Railroad Commission, by enacting Statewide Rule 50,²⁶⁴ has established a procedure for obtaining that approval.²⁶⁵

Occidental was the unit operator of a CO₂ injection flood, which began in 1984 with plans to "inject CO₂ volumes equal to [50%] of the original hydrocarbon pore volume in the reservoir."²⁶⁶ By 1995, Occidental concluded that injecting an additional 30%, for a total of 80% of the original hydrocarbon pore volume, would substantially extend the life of the project. The proposed change would trigger the Commission pre-approval process as required by both the Tax Code and Statewide Rule 50.²⁶⁷ In July 1996, Occidental applied for approval; however, in August, the Railroad Commission administratively denied approval.²⁶⁸ Nevertheless, Occidental soon began the increased CO₂ injections.²⁶⁹ Although Occidental could have requested a hearing following the denial of its application, it did not do so until July 1998.²⁷⁰ The hearings examiners denied the application because Statewide Rule 50 "clearly requires approval of an application prior to active operations,"²⁷¹ and the Commission adopted the findings and conclusions of the examiners and denied the application.

Occidental appealed, "asserting that the Commission's order was arbitrary, an abuse of discretion, and not supported by [the] evidence."²⁷²

259. *Id.*

260. 47 S.W.3d 801 (Tex. App.—Austin 2001, no pet.).

261. See TEX. TAX CODE ANN. § 202.051 (West 1992) and § 202.052(a) (West Supp. 2001).

262. *Occidental Permian Ltd.*, 47 S.W.3d at 804 (citing Act of May 24, 1991, 72d Leg., R.S., Ch. 604, §§ 1-4, 1991 Tex. Gen. Law 2196, 2196-99 (codified as TEX. TAX CODE ANN. § 202.052, .054, since amended)).

263. *Occidental Permian Ltd.*, 47 S.W.3d at 804 (quoting TEX. TAX CODE ANN. § 202.054(b) (West Supp. 2001)).

264. See 16 TEX. ADMIN. CODE § 3.50 (2001).

265. See *Occidental Permian Ltd.*, 47 S.W.3d at 804 (citing 16 TEX. ADMIN. CODE § 3.50 (West 2001)); see also *Occidental Permian Ltd.*, 47 S.W.3d at 804 n.4.

266. *Occidental Permian Ltd.*, 47 S.W.3d at 804.

267. *Id.*

268. *Id.*

269. *Id.* at 805.

270. *Id.*

271. *Occidental Permian Ltd.*, 47 S.W.3d at 805.

272. *Id.*

The court affirmed, relying upon the usual rules requiring judicial deference to administrative decisions.²⁷³ It found that both the Tax Code and Statewide Rule 50 are clear, that it was undisputed Occidental began expansion without Railroad Commission approval, and therefore, there was a reasonable basis for the Commission's decision.²⁷⁴

In deciding to proceed with the additional injections, Occidental faced the practical difficulty that the time required to secure approval was uncertain. Occidental was rapidly approaching the 50% level, and the effect of delaying the injections would be lost production and lost reserves.²⁷⁵ There is no deadline in Statewide Rule 50 regarding the time within which a hearing must be requested after an administrative denial.²⁷⁶ The court was unimpressed with Occidental's practical problems and concluded that Occidental could have started the process sooner. Having failed to do so, Occidental "made a business decision in 1996, that proceeding with its project without a tax reduction was preferable (and presumably more profitable) to taking a chance that the project would be delayed."²⁷⁷

X. ENVIRONMENTAL

*Harken Exploration Co. v. Sphere Drake Insurance PLC*²⁷⁸ is an insurance coverage case triggered by lessors filing suit against Harken for allegedly polluting Big Creek Ranch. When its insurers refused to provide a defense, Harken initiated a declaratory judgment action in state court to determine whether the insurance companies had a duty to defend.²⁷⁹ The coverage issue turned on whether lessors had alleged an "occurrence" under the policy.

The lessors alleged "that Harken operated an oil facility on the Ranch [and] that various lines, tanks, and wells [had] ruptured and overflowed, releasing pollutants, including saline substances." The damages alleged included polluted water, dead cattle, and destroyed vegetation.²⁸⁰ The insurance policies did not define "accident." Applying Texas law, the court concluded that if the act is deliberately taken, the act is performed negligently, and the effect is not the intended or expected result had the deliberate act been performed non-negligently, there is an accident.²⁸¹ Even though the lessors had alleged that Harken's conduct was malicious, the court refused to accept the insurer's contention that a malicious act cannot be negligent.²⁸² At least part of the claim was apparently covered,

273. *Id.* at 813.

274. *Id.* at 806.

275. *Id.* at 808.

276. *Occidental Permian Ltd.*, 47 S.W.3d at 808.

277. *Id.* at 807.

278. 261 F.3d 466 (5th Cir. 2001).

279. *Id.* at 469-70.

280. *Id.* at 473.

281. *Id.*

282. *Id.* at 474.

and “[i]f an insurer has a duty to defend any portion of a suit, the insurer must defend the entire suit.”²⁸³

The court also found that the allegations made by the lessors were sufficient to qualify as “sudden,” and therefore another possible exclusion to coverage was inapplicable.²⁸⁴ The court then considered the effect of the Seepage and Pollution Endorsement (S&P Endorsement) and the Saline Substances Contamination Hazard Clause (Saline Clause) and held that the S&P Endorsement and the Saline Clause re-institutes the insurance companies’ duty to indemnify and defend the insured.²⁸⁵

*Rice v. Harken Exploration Co.*²⁸⁶ holds that the Oil Pollution Act²⁸⁷ does not extend to subsurface waters and the fact that contaminated groundwater might contaminate surface waters was insufficient to establish liability. Rice alleged that Harken discharged oil into or upon “navigable waters” in violation of the OPA.²⁸⁸ “The OPA was enacted in 1990 in response to the Exxon Valdez oil spill in Prince William Sound, Alaska, and was intended to streamline federal law so as to provide quick and efficient cleanup of oil spills, compensate victims of such spills, and internalize the costs of spills within the petroleum industry.”²⁸⁹ The crux of the OPA is the regulation of facilities which discharge pollutants “into or upon . . . navigable waters.”²⁹⁰ “The OPA and its related regulations define navigable waters to mean ‘the waters of the United States, including the territorial sea.’”²⁹¹

Rice owned Big Creek Ranch. Big Creek crossed the ranch, flowed into the Canadian River, thence to the Arkansas River, thence to the Mississippi River, and finally discharged into the Gulf of Mexico.²⁹² Rice complained of a number of small spills, which cumulated over time, and the resulting groundwater contamination. “The exact nature of Big Creek [was] unclear from the record, [but] Harken did not dispute that the Canadian River was legally a ‘navigable water.’”²⁹³ Harken’s motion for summary judgment was granted on grounds that the OPA was not intended to cover spills of oil onto dry land that occurred hundreds of miles from any coast or shoreline.²⁹⁴ The case attracted amicus briefs from the U.S. Department of Justice, Environment & Natural Resources Division, the State of Texas, the Independent Petroleum Association of America, Texas Independent Producers and Royalty Owners Association,

283. *Harken*, 261 F.3d at 474 (quoting *St. Paul Fire & Marine Ins. Co. v. Green Tree Fin. Corp.-Texas*, 249 F.3d 389, 395 (5th Cir. 2001)).

284. *Id.* at 475.

285. *Id.* at 475-76.

286. 250 F.3d 264 (5th Cir. 2001).

287. 33 U.S.C. §§ 2701-2720 (2001) [hereinafter OPA].

288. *Rice*, 250 F.3d at 265.

289. *Id.* at 266 (citing Senate Report No. 104-94, reprinted in 1990 U.S.C.C.A.N. 722, 723).

290. *Rice*, 250 F.3d at 266-67.

291. *Id.* at 267 (quoting 33 U.S.C. § 2701(21) (2001); 15 C.F.R. § 990.30) (2001).

292. *Rice*, 250 F.3d at 265.

293. *Id.*

294. *Id.* at 266.

Texas Oil and Gas Association, and North Texas Oil & Gas Association.²⁹⁵

The court found that the construction given to “navigable waters” in connection with the Clean Water Act is controlling, because Congress plainly intended that “navigable waters” would have the same meaning in both the OPA and the Clean Water Act.²⁹⁶ The court found that the trial “court’s conclusion that the OPA cannot apply to *any* inland waters was erroneous,”²⁹⁷ but nevertheless found that Rice had no claim. Rice pointed to two categories of waters protected by the OPA—groundwater and Big Creek surface water.²⁹⁸ The court summarily rejected the claim as to groundwater, holding that it is well established that groundwater is not protected by the Clean Water Act, and therefore “waters of the United States” under the OPA does not include groundwater.²⁹⁹ As to Big Creek, the court held that it is not the presence of oil that grants jurisdiction under the OPA, but a body of water that is protected under the Act. A body of water is protected under the OPA only if it is actually navigable or is adjacent to an open body of navigable water.³⁰⁰

It was conceded that the Canadian River is a “navigable water” within the meaning of the OPA, and Rice contended that the pollution of the subsurface water would eventually reach the Canadian River. The court also rejected this claim and stated:

So far as here relevant, the “discharges” for which the OPA imposes liability are those “into or upon the navigable waters.” As noted, “navigable waters” do not include groundwater. It would be an unwarranted expansion of the OPA to conclude that a discharge onto dry land, some of which eventually reaches groundwater and some of the latter of which still later may reach navigable waters, all by gradual, natural seepage, is the equivalent of a “discharge” “into or upon the navigable waters.”³⁰¹

XI. LEGISLATION

A. EXPLORATION AND PRODUCTION

1. ACT: Act of June 15, 2001, 77th Leg., R.S., ch. 1233, §§ 1 - 77, 2001 Sess. Law Serv. 2691.³⁰² (S.B. 310)

295. *Id.* at 264.

296. *Id.* at 267-68.

297. *Rice*, 250 F.3d at 269.

298. *Id.*

299. *Id.* at 269-70.

300. *Id.* at 270.

301. *Id.* at 271.

302. Codified as amendments to TEX. REV. CIV. STAT. arts. 6445a, 6447, 6447b, 6447c, 6447h, TEX. NAT. RES. CODE §§ 81.0522(a), 81.0531(c), 81.0531(d), 81.116, 81.117, 85.161, 85.2021, 89.002(2)(a), 89.011, 89.043(c), 89.083(c), 89.085(a), 89.085(g), 89.085(h), 89.086(a), 89.086(c), 91.1013(a), 91.1013(b), 91.104(b), 91.104(c), 91.1041, 91.1042, 91.107, 91.108, 91.109, 91.111(b), 91.111(c), 91.112, 113.011, 113.014, 113.015, 113.0511, 113.082, 113.084(b), 113.084(c), 113.087(b), 113.087(c), 113.087(i) - (m), 113.089(a), 113.089(c), 113.090(a), 113.090(b), 113.091(b), 113.091(c), 113.091(d), 113.093, 113.096, 113.097(d), 113.097(h), 113.098(a), 113.098(c), 113.099(a) - (d), 113, subch. F heading, 113.161(e),

ISSUE: RELATING TO THE CONTINUATION AND FUNCTIONS OF THE RAILROAD COMMISSION.

SUMMARY: This Act increases the funding for the Oil Field Cleanup Fund ("OFCF") by increasing the oil-field cleanup regulatory fees on crude oil by 5/16 cent and on natural gas by 1/30 cent, together with \$100 increases in fees for drilling and workovers of wells, requests to expedite drilling and workover permits, fluid injection permits, surface water discharge permits, and rule exceptions, except for well spacing and density exceptions, which have a \$150 increase.

This Act also establishes a new sliding scale filing fee for annual P-5 Organization reports. The filing fee scale ranges from \$300 to \$1,000. In addition, there is a new \$1,000 application fee for the Voluntary Cleanup Program.

This Act increases the cost for an annual W-1X plugging extension to \$300 until September 1, 2004, and increases to \$1,000 the annual cost for a "good guy" fee. This "good guy" fee is only applicable if the Railroad Commission determines that individual and blanket bonds are not obtainable at reasonable prices and the applicant meets the "good guy" standards of compliance. An increase to 12.5% of the bond requirement for an operator who cannot meet the "good guy" compliance standards is also imposed. In addition, the fund cap is increased to \$20 million, relative to collection of regulatory fees on oil and gas production.

This Act also provides that the proceeds from bonds and other required financial securities may be used only for actual well plugging and surface remediation, and it makes the current bonding amounts applicable only to land well operations. The Railroad Commission is authorized to set "reasonable" additional bonding requirements for operators of offshore and bay wells. In addition, effective September 1, 2004, the W-1X alternatives for plugging security are eliminated, and instead requires a Railroad Commission approved bond, letter of credit, or cash deposit as financial security. Effective September 1, 2004, the bonding requirement for persons involved in activities other than the operation of wells is increased to \$250,000; unless, a person demonstrates to the Commission that a lesser amount is warranted and makes this bonding requirement in addition to any other required financial security requirement.

113.163, 113.233(b), 113.243(b), 113.243(c), 113.243(d), 116.037, 116.037(f), 116.037(g), TEX. UTIL. CODE §§ 102.001, 103.001, 104.107(b), 121.103(a), 121.2015, 121.206(c), ch. 121, subch. J heading, 121.501 - 121.506, adding TEX. REV. CIV. STAT. arts. 6447k, 6447l, 6447m, 6447n, TEX. NAT. RES. CODE §§ 81.0521(a), 81.0521(c), 81.0531(e), 81.055, 81.056, 91.111(e), 91.1131, 91.1132, 91.1135, 91.142(g), 91.651, 91.652, 91.653, 91.654, 91.655, 91.656, 91.657, 91.658, 91.659, 91.660, 91.661, 113.087(n), 113.087(o), 113.243(f), 113.243(g), ch. 113, subch. J and K headings, 113.351, 113.352, 113.353, 113.354, 113.355, 113.356, 113.357, 116.016, 116.033, 116.034(d) - (k), 116.0345, 116.0346, 116.037(h), 117.012(h) - (k), 118.001, 118.002, 118.003, 118.004, 118.005, TEX. UTIL. CODE §§ 102.006, 103.003, 104.107(c), 104.2551, 121.103(d), 121.206(d), 121.5005, TEX. GOV'T CODE § 2003.0491, and repealing TEX. NAT. RES. CODE ch. 93, §§ 113.002(2), 113.012, 113.013, 113.243(b), 223.246 (Vernon Supp. 2001).

Effective immediately, any well transferred, sold, or assigned to another party by its operator must be bonded in accordance with the statutes then in effect before the Railroad Commission approves the transfer of ownership. A transfer of a well from one entity to another entity under common ownership is a "transfer" which requires bonding.

This Act requires the Railroad Commission, through the legislative appropriations process, to establish specific performance goals for the OFCF for the next biennium. Goals for the number of site investigations, environmental assessments, well pluggings, and surface location remediations must also be made. In addition, the Railroad Commission's annual OFCF report to the legislature must include performance statistics by region together with a detailed accounting of expenditures.

This Act also establishes a ten member OFCF Advisory Committee, to be composed of the executive officer, or designee, of each of the five Texas Oil and Gas Associations, the chairs of the Senate Natural Resources and House Energy Resources Committees, a public member appointed by the Governor, one member appointed by Speaker of the House, and one member appointed by the Lieutenant Governor. The latter two members must be from the academic fields of geology or economics. The Committee must meet at least quarterly with the Railroad Commission to receive information about proposed rules relating to the OFCF, review recommendations for Railroad Commission proposed legislation, and monitor OFCF effectiveness. The Committee must report to the Governor, Lieutenant Governor, and the Speaker of the House an analysis of any administration problems of the OFCF and any recommendations for legislation needed to further the OFCF's purpose. This report must be given on or before November 15 of each year preceding a regular legislative session.

This Act also requires the Railroad Commission to develop a system for identifying abandoned wells that pose a high risk of contaminating surface water or groundwater. It also authorizes the Commission to adopt rules establishing risk assessment as the guide for conducting site investigations and environmental assessments and for controlling and cleaning up oil and gas wastes. The Act provides general provisions which are to be included in any such rules.

This Act mandates that an operator, when plugging a well where useable quality water zones are present, verify that the placement of the plug is at the base of the deepest fresh water zone required to be protected. If the operator plugs the well back to produced fresh water, the operator's duty to properly plug the well ends only when the well has been properly plugged in accordance with the Railroad Commission's requirements and, if applicable, the surface owner has obtained a permit for the well from the groundwater conservation district.

This Act also creates the Railroad Commission Voluntary Cleanup Fund (VCP), and authorizes the OFCF to be used for implementing the VCP. The purpose of the VCP is to provide incentives to lenders, devel-

opers, owners and operators who did not cause or contribute to contamination at an oil-field site to remediate the problem. The VCP does this by releasing a person who is certified by the Railroad Commission as having completed such remediation from all liability to the state for future site cleanup other than that caused or contributed to by that person. The surface owner of a particular oil-field site must give written authorization agreeing to an applicant's participation in the program. A formal agreement, setting forth the terms and conditions for the Railroad Commission's evaluation of the proposed remediation goals, methods used for the remediation, and the implementation of work plans, is required, and the applicant must pay all costs attributable to the Commission's oversight of the voluntary cleanup.

This Act authorizes the legislature to study, not later than March 1, 2002, the desirability of requiring an owner, operator, or manager of a pipeline system to obtain liability insurance coverage, a bond, or some other evidence of financial responsibility in order to protect the public from the costs resulting from a discharge of the pipeline system and to make its report available to the public. Should the legislature find that the adoption of such a requirement is desirable, the Railroad Commission is authorized to require an owner, operator, or manager of a pipeline system to obtain evidence of financial responsibility. The evidence of financial responsibility may be in different amounts for different pipeline systems, considering the age of the pipeline system and the location of the pipelines.

This Act also requires that a notice of pipeline construction be published at least 30 days before the start of construction for a new pipeline system, or for the extension of an existing pipeline system, that crosses more than three counties and for which construction begins after September 1, 2001. The Railroad Commission has a duty to certify, before issuing a permit for the operation of such a pipeline, that a copy of the application has been given at least ninety days earlier to each county judge, county fire marshal, and regional water planning group whose respective jurisdictions contain part of the proposed pipeline route.

This Act provides that pipeline operator liaison meetings with fire, police and other appropriate public officials in preparation for possible emergency response to a pipeline accident are to be conducted in person, if possible. If the pipeline operator cannot arrange for a meeting in person, the operator must make specified efforts to conduct community liaison meetings by means of a telephone conference call. If the operator cannot arrange for a meeting in person or a telephone conference call, the operator may deliver the necessary information by certified mail, return receipt requested, to the appropriate officials. In addition, the operator or owner of each inter- or intrastate hazardous liquid or carbon dioxide pipeline facility that is located within 1,000 feet of a public school is required to develop an emergency response plan in consultation with the local fire department or another local emergency response entity.

Such a plan must be presented to the board of trustees of the school district.

This Act also authorizes the Railroad Commission to adopt rules requiring an operator to file a plan of assessment or testing of a pipeline for approval if the Commission believes that the pipeline may present a hazard to public health or safety, or if the Commission lacks adequate information to assess the risk to public health and safety. The Commission may specify to which pipelines under their jurisdiction such requirements are applicable. However, it is expressly stipulated that Commission approval of such a plan does not constitute certification or representation that the pipeline is in compliance with or exempt from the applicable safety standards. The Commission is directed to adopt regulatory guidelines to be used in determining the amount of a penalty for a violation of their pipeline safety regulations. The Act provides that the guidelines shall include a penalty calculation worksheet that specifies the typical penalty for certain violations, along with a listing of circumstances which would justify an enhancement or reduction in the penalty and the amount of such a change.

This Act also requires the utility division of the State Office of Administrative Hearings (SOAH) to conduct each hearing in a contested gas utilities rate case that is not conducted by one or more members of the Railroad Commission. The Commission is allowed to delegate to the SOAH the authority to make a final decision and to issue findings of facts, conclusions of law, and other necessary orders in a proceeding in which there is not a contested issue of fact or law.

This Act also authorizes the Railroad Commission to increase the fee for a Natural Gas Policy Act well category determination to \$150.

EFFECTIVE: September 1, 2001, except for provisions noted in summary.

2. **ACT:** Act of June 14, 2001, 77th Leg., R.S., ch. 824, §§ 1 - 4, 2001 Leg. Sess. Law Serv. 1549.³⁰³ (H.B. 981)

ISSUE: RELATING TO OIL AND GAS REPORTING STANDARDS.

SUMMARY: This Act requires that a property name, county, and state be included on the check stub in addition to the items already required by statute. A telephone number where the royalty owner can contact the company to inquire about payment questions is also required to be on the check stub. Inquiries about certain types of check stub information, such as property descriptions, details about deductions or adjustments, heating value of the gas, or a report of associated Railroad Commission numbers, can be done by certified mail, and must be handled within 60 days of receipt. The payor must also send a notice once a year to the royalty owners it is paying and advise them that the owner may request additional information and how to obtain production information

303. Codified as TEX. NAT. RES. CODE § 91.5001, amending §§ 91.501 - 91.506, and adding § 91.507 (Vernon Supp. 2001).

from the Railroad Commission. Payors who fail to timely respond to such a request by certified mail may be subject to a lawsuit or voluntary mediation, where the loser must pay reasonable court costs and attorney fees.

EFFECTIVE: January 1, 2002, except for the check stub information, which takes effect September 1, 2002.

3. **ACT:** Act of June 14, 2001, 77th Leg., R.S., ch. 858, §§ 1-3, 2001 Sess. Law Serv. 1609.³⁰⁴ (H.B. 1669)

ISSUE: RELATING TO THE DUTY OF AN OPERATOR OF AN UNDERGROUND FACILITY TO NOTIFY AN EXCAVATOR OF THE OPERATOR'S INTENTIONS.

SUMMARY: This Act requires the operator of an underground facility contacted by a one-call center to notify the excavator within 48 hours of the time the excavator gave notice of intent to excavate, if the operator does not plan to mark the proximate location of an underground facility at or near the site of the proposed excavation. The notice to the excavator must be given by e-mail or by facsimile or by another verifiable and approved electronic method.

EFFECTIVE: November 1, 2001.

4. **ACT:** Act of June 13, 2001, 77th Leg., ch. 652, §§ 1-4, 2001 Sess. Law. Serv. 1149.³⁰⁵ (H.B. 2391)

ISSUE: RELATING TO FEES AND PENALTIES RELATING TO NOTIFICATION OF UNDERGROUND EXCAVATION.

SUMMARY: This Act provides for a ten-fold increase in the minimum and maximum financial penalties for excavator violations of the Underground Facility Damage Prevention and Safety Act.³⁰⁶ In lieu of a civil penalty, the county or district attorney may give a violator a warning letter and require attendance at a Texas Underground Facility Notification Center (TUFNC). In addition, this Act increases from one cent to five cents the TUFNC fee for each excavator call to a one-call center and requires the TUFNC to waive the fee for the remainder of any year in which the corporation receives \$250,000.

EFFECTIVE: September 1, 2001.

5. **ACT:** Act of June 15, 2001, 77th Leg., R.S., ch. 1200, §§ 1 - 3, 2001 Sess. Law Serv. 2576.³⁰⁷ (H.B. 3587)

ISSUE: RELATING TO GROUNDWATER CONSERVATION DISTRICTS.

304. Codified as an amendment to TEX. UTIL. CODE § 251.152, and adding § 251.157(d) (Vernon Supp. 2001).

305. Codified as an amendment to TEX. UTIL. CODE §§ 251.106, 251.201, and adding § 251.2011 (Vernon Supp. 2001).

306. TEX. UTIL. CODE § 251.001 et seq.

307. Codified as an amendment to TEX. WATER CODE § 36.117 (Vernon Supp. 2001).

SUMMARY: This Act modifies exemptions, exceptions, and limitations on water well permitting requirements for groundwater conservation districts in three ways. First, this Act changes the exemption for hydrocarbon production activities to include only a well used to supply water solely for a drilling rig which is actively engaged in drilling or exploration operations for a well permitted by the Railroad Commission, provided that the person holding the permit is responsible for the water well and that the well is located on the lease. Furthermore, a district may not deny an application for a permit to drill and produce water for hydrocarbon production activities if the application is in compliance with the spacing, density, and production rules of the district. Second, this Act provides that a district may require a well used for drilling rig water supply or mining purposes be permitted if the well is no longer used for those purposes. And, third, this Act provides that an exemption in the Act does not affect a district's authority either to impose fees regarding the transfer of groundwater out of the district or to levy taxes or collect fees.

EFFECTIVE: September 1, 2001.

6. **ACT:** Act of June 15, 2001, 77th Leg., R.S., ch. 966, §§ 1 - 13, 2001 Sess. Law Serv. 1880.³⁰⁸ (S.B. 2)

ISSUE: RELATING TO THE DEVELOPMENT AND MANAGEMENT OF THE WATER RESOURCES OF THE STATE.

SUMMARY: This Act clarifies that ownership of and rights to groundwater by landowners and their lessees and assigns may be limited or altered by rules promulgated by a Groundwater Conservation District (GCD).

Specifically, this Act provides that a GCD may impose more restrictive permit conditions on new water well permit applications and increased use by historic users if three conditions are met. First, the limitations must apply to all subsequent new permit applications and increased use by historic users, regardless of type or location of use. Second, the limitations bear a reasonable relationship to the existing district management plan. Third, the limitations are reasonably necessary to protect an existing use.

This Act also authorizes a GCD to regulate water well spacing and to limit production. This authority is granted to minimize the drawdown of

308. Codified as TEX. WATER CODE §§ 9.001 - 9.017, 11.002(11) - (14), 26.050, and amending TEX. WATER CODE §§ 11.023(a), 11.024, 11.122(a), 11.134(b), 11.142, 16.053(d), 16.053(e), 16.054(a), 16.504(c), 16.504(d), 35.002(11), 35.004, 35.007(a), 35.007(f), 35.008, 35.009(a), 35.009(b), 35.012, 35.013, 35.018(c), 36.001(13), 36.0015, 36.002, 36.011(b), 36.013, 36.01436.015, 36.0151(a), 36.016(a), 36.017(a), 36.017(d), 36.017(g), 36.019, 36.060(a), 36.066(g), 36.101(a), 36.102(b), 36.1071(a), 36.1071(b), 36.108, 36.113(d), 36.116, 36.117, 36.122, 36.205, 36.206(b), 36.303(a), 51.149, 26.0286, 13.137, 13.144, 13.183(c), 13.187, 26.359, 36.121, TEX. TAX CODE § 11.32, TEX. UTIL. CODE § 182.052(a), and adding TEX. WATER CODE §§ 13.2541, 13.145, 13.183(d), 13.183(e), 13.343, 15.602(8), 17.8955, 17.9615, 17.9616, 26.117(h), 27.051(h), 36.001(18) - (22), 36.012(f), 36.017(i), 36.0171, 36.1071(h), 36.1072(g), 36.113(e), 36.206(c), 36.3011, 36.3035, TEX. TAX CODE § 151.355, and relettering TEX. WATER CODE §§ 36.113(e) and (f) to (f) and (g), and redesignating the existing TEX. WATER CODE §§ 15.602(8) - (14) to 15.602(9) - (15), and repealing TEX. WATER CODE §§ 35.005, 35.006 (Vernon Supp. 2001).

the water table, or to minimize the reduction of artesian pressure, as well as to control subsidence and interference between wells, to protect against the degradation of water quality, and to prevent waste. The district may preserve historic use before the effective date of the rules to the maximum extent practicable so long as doing so would be consistent with the district's comprehensive management plan.

Much like H.B. 3587,³⁰⁹ this Act provides that a GCD may not deny an application for a permit to drill and produce water for hydrocarbon production activities if the application is in compliance with the applicable district rules. Also, the GCD may not require a permit for drilling a water well used solely to supply water for a drilling rig that is actively engaged in drilling or exploration operations for a Railroad Commission-permitted oil or gas well, provided that the person holding the Railroad Commission permit is responsible for drilling and operating the water well and that the water well is located on the same lease or field associated with the drilling rig. However, a GCD may require that such a well be permitted by the district if the well is no longer used solely for the purposes specified. Furthermore, a water well exempted from getting a permit must be registered, and a drilling log filed, with the GCD.

This Act also authorizes a GCD, provided it is not a GCD that collects a property tax and was created before September 1, 1999, to assess, and use for any lawful purpose, production fees in lieu of or in conjunction with any taxes otherwise levied by the district. The fees may be based on either the amount of water authorized by permit to be withdrawn from a well or the amount actually withdrawn. With respect to the latter, production fees are capped at \$1 per acre-foot, payable annually, for water used for agricultural purposes and at \$10 per acre-foot, payable annually, for water used for any other purpose. The GCD is also authorized to assess a production fee for water produced under an exemption if such water is later sold to another person or transported outside the boundaries of the district.

This Act also provides that the fee assessed by the GCD for a permit for the transfer of groundwater outside of the district may not exceed the fees that the GCD imposes for processing other permit applications. Nevertheless, the GCD may assess a reasonable export fee, which may be (1) negotiated between the district and the transporter of the water; (2) a rate not to exceed the district's tax rate per hundred dollars of valuation, with a minimum of 2.5 cents for each thousand gallons of water transferred out of the district; or (3) for those districts which are fee-based, a 50 percent export surcharge in addition to the district's production fee.

EFFECTIVE: September 1, 2001.

309. See *supra* note 307 and accompanying text.

7. ACT: Act of June 15, 2001, 77th Leg., R.S., ch. 1227, §§ 1 - 14, 2001 Sess. Law Serv. 2656.³¹⁰ (S.B. 220)

ISSUE: RELATING TO THE REGULATION AND ENFORCEMENT OF WEIGHT LIMITATIONS AND SAFETY STANDARDS FOR CERTAIN MOTOR VEHICLES.

SUMMARY: This Act amends the Transportation Code to clarify weight tolerances for specific vehicles and to restrict vehicles that are operating under a special tolerance permit from operating on a bridge for which maximum weight and load limits have been established by the Texas Transportation Commission or by a county commissioners court, if the gross weight of the vehicle and load or if the axles and wheel loads are greater than the established and posted limits. However, this restriction does not apply if the bridge is along the only public highway or road that the permitted vehicle can use to travel from its point of origin to its destination. In addition, this Act establishes that those persons operating certain vehicles who fail to keep a weight record are guilty of committing a Class C misdemeanor.

EFFECTIVE: September 1, 2001.

8. ACT: Act of May 11, 2001, 77th Leg., R.S., ch. 99, §§ 1 - 3, 2001 Sess. Law Serv. 179.³¹¹ (S.B. 405)

ISSUE: RELATING TO THE REGULATION OF PROFESSIONAL GEOSCIENTISTS.

SUMMARY: This Act establishes the Geoscience Practice Act and the Texas Board of Professional Geoscientists. The Board is charged with the responsibility of administering licenses, certificates, seals and generally regulating the public practice of geology, geophysics, soil science, and various specialties within those fields. The Act provides an exemption for "geoscientific work performed exclusively for and developing oil, gas, or other energy resources . . . if the work is done in and for the benefit of private industry."³¹²

EFFECTIVE: September 1, 2001, except for the licensing requirements and the administrative penalties for violating the Act, which go into effect on September 1, 2003.

9. ACT: Act of May 22, 2001, 77th Leg., R.S., ch. 276, §§ 1-2, 2001 Sess. Law Serv. 498.³¹³ (S.B. 1338)

ISSUE: RELATING TO THE AUTHORITY OF THE RAILROAD COMMISSION TO REGULATE OIL AND GAS NORM WASTE.

310. Codified as an amendment to TEX. TRANSP. CODE §§ 251.153(a), 621.101, 621.301(a), 623.011(c), and adding §§ 261.001(10), 261.001(11), 621.007, 621.410, 621.509, 623.0113, 644.005 (Vernon Supp. 2001).

311. Codified as TEX. REV. CIV. STAT. art. 3271(b), and as an amendment to TEX. LOCAL GOV'T CODE §§ 112.0101(a), 232.0031(a) (Vernon Supp. 2001).

312. *Id.* at § 6.02(3).

313. Codified as an amendment to TEX. HEALTH & SAFETY CODE § 401.415 (Vernon Supp. 2001).

SUMMARY: This Act authorizes the Railroad Commission to require owners and operators of oil and gas equipment to determine whether the equipment contains or is contaminated with oil and gas NORM waste and to identify any such equipment found.

EFFECTIVE: May 22, 2001.

B. ENVIRONMENTAL

1. **ACT:** Act of June 15, 2001, 77th Leg., R.S., ch. 965, §§ 1 - 20, 2001 Sess. Law Serv. 1825.³¹⁴ (H.B. 2912)

ISSUE: RELATING TO THE CONTINUATION AND FUNCTIONS OF THE TEXAS NATURAL RESOURCE CONSERVATION COMMISSION.

SUMMARY: This Act renames the Texas Natural Resource Conservation Commission to the Texas Commission on Environmental Quality, effective January 1, 2004. In addition, this Act creates or modifies current environmental issues in numerous ways.

First, while not creating an independent Office of Public Interest Council, this Act authorizes the TNRCC's Public Interest Council to recommend needed legislative and regulatory changes and creates a Joint Interim Study to address issues related to creating an independent Public Interest Council office. One specific issue to be addressed involves studying the authority to appeal decisions of the TNRCC by the Public Interest Council.

Second, this Act requires the owner or operator of a facility that experiences emissions events—defined as upsets or unscheduled maintenance, startup, or shutdown activities that result in unauthorized emissions of air contaminants—to maintain a record of all such events at the facility and to notify the commission, as soon as practicable but not later than 24 hours after discovery, when such an event exceeding a reportable quantity occurs. The owner or operator is also directed to report specific information to TNRCC within two weeks of an reportable quantity release so that the TNRCC may evaluate the emissions event.

Third, this Act separates Texas into East Texas and West Texas, with the dividing line being all counties traversed by or east of Interstate Highway 35 north of San Antonio or Interstate Highway 37 south of San Antonio and grandfathered facilities in the East Texas region must submit a permit application or a notice of shutdown by September 1, 2003,

314. Codified as TEX. HEALTH & SAFETY CODE § 382.056(r), amending TEX. HEALTH & SAFETY CODE §§ 361.0231(a), 382.051(a), 382.051(b), 382.05191, 382.0592, 366.076, 361.114, 382.019(a), 382.037(g), 382.039(a), 366.0512, TEX. WATER CODE §§ 5.107, 5.176, 5.177, 5.178(b), 5.228, 27.003, 26.0291, 26.0135(h), 7.031(c), 26.342(9) - (17), 26.028(d), 26.040(h), 27.051(d), 27.051(e), adding TEX. HEALTH & SAFETY CODE §§ 366.059(d), 361.088, 382.0215, 382.0216, 382.05181 - 382.05186, 382.065, 361.1875, 382.037(h), 382.037(i), TEX. WATER CODE §§ 5.103(d), 5.5145, 5.702 - 5.708, 5.127 - 5.131, 5.1733, 5.1765, 5.1771, 5.1772, 5.1773, 7.0025, 7.031(f), 26.3571(g), 26.3571(h), 26.3573(r), 26.3573(s), 27.051(h), transferring and amending TEX. REV. CIV. STAT. art. 6243-101 to TEX. HEALTH & SAFETY CODE §§ 341.101 - 341.105 (Vernon Supp. 2001).

and to fully comply with the resultant permit conditions by September 1, 2007, or it must cease operations. West Texas must do the same, but has until September 1, 2004, and September 1, 2008, to do so.

Fourth, this Act provides that grandfather reciprocating internal combustion engines that are part of a processing, treating, compressing or pumping facility connected to or part of a gathering or transmission pipeline may be permitted under a single permit. For the East Texas regions, a 50% reduction in the hourly emission rate of nitrogen oxides and up to a 50% reduction in the hourly emission rate of volatile organic compounds, each expressed in terms of grams per brake horsepower, is required. For the West Texas region, the TNRCC is allowed to require up to a 20% reduction of both compounds.

Fifth, this Act creates a comprehensive performance-based regulation program applicable to TNRCC permitting and enforcement programs and authorizes innovative programs which provide incentives for benefits to the environment that exceed the benefits that would result from compliance with applicable legal requirements under the commission's jurisdiction, including the flexible permit program for air permits and the general regulatory flexibility program.

Sixth, this Act prohibits the TNRCC from establishing standards regarding motor vehicle fuels that are more stringent or restrictive than those imposed by the United States' Environmental Protection Agency for the same area of the state before January 1, 2004, except for Texas low-emission diesel, which may not be required before February 1, 2005. In addition, this Act authorizes the TNRCC to consider alternative fuels to achieve equivalent emissions reductions.

Seventh, this Act amends section 5.103 of the Water Code to clarify the TNRCC's general jurisdiction and to specify that it does not delegate legislative authority.

Eighth, this Act requires the TNRCC to include, as part of each rule proposed and adopted, a citation to the specific statutory authority justifying the proposed or adopted rule. If a rule is adopted without such a citation, the rule is void.

Ninth, this Act requires the TNRCC to make reasonable attempts to have a balanced representation on all advisory committees, work groups, and task forces; however, a rule or other action may not be challenged because of the composition of an advisory committee, work group or task force. The TNRCC is required to maintain information on the composition and activities of such groups in both a form and a location that is easily accessible to the public.

Tenth, this Act places requirements on the data and analysis used in Commission decisions relating to the permits or other authorizations and actions, such as compliance matters, enforcement actions or corrective actions. The Act does this by requiring the TNRCC to accept environmental testing laboratory data and analyses only from TNRCC or feder-

ally accredited laboratories or from TNRCC inspected onsite or in-house laboratories.

Eleventh, this Act directs the TNRCC to encourage the use of electronic reporting for reports required by the commission and to strive to reduce duplication in reporting requirements throughout the agency.

Twelfth, this Act requires a succinct summary statement for each public notice issued or published by the commission or by a person under the jurisdiction of the commission. The summary statement must be designed to inform the reader of the subject matter of a notice without requiring him to read the entire text of the notice. However, the summary statement may not be used as a grounds by which the validity of the action proposed in the notice may be challenged.

Thirteenth, this Act directs the TNRCC to develop and implement policies which will protect the public from cumulative risks in areas where there are concentrated operators. In formulating such policies, the TNRCC is directed to give priority to monitoring and enforcement in areas where regulated facilities are concentrated.

Fourteenth, this Act requires the TNRCC to adopt regulatory incentives in order to encourage the use or environmental management systems (EMS) by regulated entities, local and state agencies, and local governmental bodies. Such EMS incentives may include on-site technical assistance, accelerated access to information about TNRCC programs, the inclusion of information regarding the use of an EMS in an entity's compliance history and summaries, and consideration of EMS implementation in the scheduling and conducting of compliance inspections.

Fifteenth, this Act requires the TNRCC to post public information, including pending permit and enforcement actions, compliance histories, and emissions inventories, by county and facility name on its website.

Sixteenth, this Act requires the Commission to establish and publish information relating to the process used for educating the public regarding TNRCC's complaint policies and procedures. The TNRCC is also directed to develop procedures in order to timely respond to complaints made outside of regular business hours. However, in formulating such procedures, this Act does not authorize any additional use of overtime. In addition, this Act requires a comprehensive analysis of complaints received by the TNRCC.

Seventeenth, this Act requires that the executive director (E.D.) be named a party in TNRCC hearings in matters in which the E.D. bears the burden of proof. During a contested case hearing relating to a permit application, the E.D. is prohibited from rehabilitating the testimony of a witness, other than a TNRCC employee, and is prohibited from assisting a permit applicant in meeting its burden of proof during such a hearing. This Act does, however, require the TNRCC to establish categories of permit applicants who are exempt from this general prohibition and are thus eligible to receive such assistance. This Act also provides that the E.D. may nevertheless participate as a party in contested case permit

hearings for the sole purpose of providing information to complete the administrative record. Before participating as a party, the E.D. must consider certain factors, specified in rules to be adopted by the TNRCC, in determining, case by case, whether to participate as a party in a contested case permit hearing.

Eighteenth, this Act requires that a draft permit, which is being presented to the Commission for action, include a summary of changes to the applicant's proposal as required by the E.D. in order to increase protection of the public health and the environment.

Nineteenth, this Act authorizes the TNRCC to initiate an enforcement action that is based upon information it receives from a private individual, provided that the information is of sufficient value and credibility to warrant the initiation of an enforcement action.

Twentieth, this Act authorizes the TNRCC to take into consideration the economic development of the state in its decisions and actions.

Twenty-first, this Act prohibits the storage, processing, or disposal of hazardous waste in a solution-mined salt dome cavern or in a sulphur mine.

Twenty-second, this Act prohibits the Commission from naming a person as a responsible party in a remediation project if the Commission finds that the contaminants appear to originate from an off-site source, that additional action is not required at the site, and that the TNRCC will not undertake formal enforcement.

EFFECTIVE: September 1, 2001, except as noted in the summary.

2. **ACT:** Act of June 16, 2001, 77th Leg., R.S., ch. 1327, §§ 1 - 5, 2001 Sess. Law Serv. 3097.³¹⁵ (H.B. 2518)

ISSUE: RELATING TO THE ISSUANCE OF PERMITS FOR THE EMISSION OF AIR CONTAMINANTS.

SUMMARY: This Act provides that air emissions construction permit amendments, which will result in de minimus emission increases with no changes in the character of the emissions, are not subject to public notice requirements. In addition, this Act requires that the commission, in considering a permit amendment under this section, consider any adjudicated decision or compliance proceeding relating to the applicant's compliance with air emissions laws and regulations within the five years before the date on which the application was filed.

EFFECTIVE: September 1, 2001.

3. **ACT:** Act of June 15, 2001, 77th Leg., R.S., ch. 1135, §§ 1 - 12, 2001 Sess. Law Serv. 2389.³¹⁶ (H.B. 2687)

315. Codified as an amendment to TEX. HEALTH & SAFETY CODE §§ 382.0516, 382.0518(a), 382.0518(b), 382.0518(c), 382.0518(d), 382.0518(e), 382.056(a), 382.056(g), and adding § 382.0518(h) (Vernon's Supp. 2001).

316. Codified as an amendment to TEX. WATER CODE §§ 26.342(9) - (17), 26.346(a), 26.346 (c), 26.3512(b), 26.355(d), 26.3571(b), 26.3572(b), 26.3573(d), 26.3574(b), 26.3574(x), 26.3574(y), 26.3574(z), 26.3574(aa), 26.361, adding § 26.342(18), 26.351(f), 26.351(g),

ISSUE: RELATING TO THE PROGRAM OF REGULATION AND REMEDIATION OF UNDERGROUND AND ABOVE-GROUND STORAGE TANKS.

SUMMARY: This Act extends the life of the groundwater protection cleanup program for petroleum storage tank remediation until September 1, 2006, reduces by one-third the delivery fees for users of certain petroleum products, and deletes the fund cap of \$100 million. In addition, this Act requires a person who has reported a release to TNRCC on or before December 22, 1998, and who is performing corrective action under this program, to meet certain deadlines while detailing consequences for failure to meet these deadlines.

EFFECTIVE: September 1, 2001.

4. ACT: Act of June 15, 2001, 77th Leg., R.S., ch. 1158, §§ 1 - 105, 2001 Sess. Law Serv. 2431.³¹⁷ (H.B. 2914)

ISSUE: RELATING TO STATE FISCAL MATTERS.

SUMMARY: This Act authorizes the TNRCC to adopt a reimbursement program for emissions reductions from grandfathered reciprocating internal combustion engines associated with pipelines in the East Texas region. The reimbursement amount is equal to up to 50% of the capital costs, excluding interest, required to achieve a 50% emissions reduction minus the amount that it costs to achieve a 30% emissions reduction. However, the possible reimbursement amount is capped at \$100,000 for each emission reduction project and \$250,000 for any person. In addition, in order to be eligible for reimbursement under this program, the applicant facility must be reducing its hourly emissions rate of nitrogen oxides by at least 50%. The Comptroller is directed to establish the Emissions Reduction Incentives Account, which is to consist of gifts and other sources designated by the legislature. The TNRCC is authorized to use up to \$16,200,000, plus any interest, from donations to this fund for reimbursement of certain grandfathered pipeline facility engine emission reductions. The emissions reduction project must be initiated before March 1, 2006, and completed before March 1, 2007. The TNRCC may not make any reimbursements before the project is complete, and no reimbursements will be made after March 1, 2007.

However, this Act provides that reimbursements will not be made when a portion of the reductions generated are used to offset the emissions reductions required to be made at another facility, or where the reductions to be made are required by another federal or state law, regulation, permit, or order.

Furthermore, this Act provides that the reimbursement program does not affect the responsibility or liability of grandfathered facility owners or

26.351(h), 26.3571(g), 26.3571(h), 26.3573(r), 26.3573(s), and repealing § 26.361(b) (Vernon Supp. 2001).

317. Codified as TEX. HEALTH & SAFETY CODE § 382.051865 (Vernon Supp. 2001).

operators to reduce emissions under this chapter or any other TNRCC rule, permit, or order.

In addition, this Act provides that gifts or contributions by an electric utility or an affiliated power generating company to a program implemented under this section shall be considered as a tangible or intangible capital cost to improve air quality which is deemed to have occurred before January 1, 2002, and it shall be included in the electric utility's generation-related invested capital. Furthermore, such gifts or contributions shall be deemed to be a legitimate and necessary cost to offset the emission of airborne contaminants from electric generating facilities.

EFFECTIVE: June 15, 2001.

5. ACT: Act of June 15, 2001, 77th Leg., R.S., ch. 967, §§ 1 - 22, 2001 Sess. Law Serv. 1970.³¹⁸ (S.B. 5)
- ISSUE: RELATING TO THE TEXAS EMISSIONS REDUCTION PLAN.

SUMMARY: This Act requires the TNRCC, PUC, Comptroller, and the new 15 member Texas Council on Environmental Technology (TCET) to establish and implement the "Texas Emissions Reduction Plan," (Plan) and creates the "Texas Emissions Reduction Plan Fund" to pay for the Plan. The Plan and other provisions in this Act are directed at achieving emission reductions, primarily nitrogen oxides, from mobile sources and other specified sources such as air conditioners, heaters, and water heaters, but not from point sources.

This Act requires the TNRCC, the comptroller, and the council to provide grants or funding under the Plan for the following: 1) the diesel emissions reduction incentive program, including a purchase or lease incentive program for new on-road diesels; 2) the motor vehicle purchase or lease incentive program for new light duty vehicles; and 3) the new technology research and development program, under which the TCET is to identify, evaluate, and deploy new technologies and assist the TNRCC and the EPA in the process of ensuring credit for technological advancements.

This Act also requires the PUC to provide grants or funding for the energy efficiency grant program to increase the retirement, replacement, and recycling of materials and appliances that contribute to peak energy demand. These programs are sunsetted on August 31, 2008.

This Act also requires the adoption and enforcement of Texas Building Energy Performance Standards for both residential and commercial/industrial buildings by municipalities.

This Act also requires the TNRCC to take all appropriate and necessary actions in order for the EPA to credit the emissions reductions

318. Codified as TEX. HEALTH & SAFETY CODE §§ 386.001 - 386.252, 387.001 - 387.010, 388.001 - 388.008, 389.001 - 389.002, amending TEX. TAX CODE §§ 151.0515, 153.203, and adding TEX. TAX CODE § 152.0215, TEX. TRANSP. CODE §§ 224.153(c), 341.073(d), 502.1675, 502.186, 548.256(c), 548.256(d), 548.5055 (Vernon Supp. 2001).

achieved under the Plan and the Texas building energy performance standards to appropriate emissions reduction objectives in the state implementation plan.

This Act also provides for funding, through fees, of the Plan. The fees include: 1) a 10% surcharge on the registration of a truck-tractor or commercial motor vehicle; 2) a \$10 surcharge on the annual inspection of a commercial vehicle; 3) a \$225 initial vehicle inspection fee for a vehicle brought into Texas, unless owned by a person in the armed forces of the United States; 4) a 1% surcharge on the retail sale, lease, or rental, of new or used equipment; and 5) a 2.5% surcharge on every retail sale or lease of any model year 1996 or earlier on-road diesel motor vehicle over 14,000 pounds.

EFFECTIVE: September 1, 2001.

6. ACT: Act of June 17, 2001, 77th Leg., R.S., ch. 1483, §§ 1 - 2, 2001 Sess. Law Serv. 4972.³¹⁹ (S.B. 356)

ISSUE: RELATING TO THE PERFORMANCE MEASURES FOR INNOVATIVE REGULATORY PROGRAMS IMPLEMENTED BY THE NATURAL RESOURCE CONSERVATION COMMISSION.

SUMMARY: This Act requires the TNRCC to work with the Legislative Budget Board to create performance measures that assess the improvements in environmental quality achieved by innovative regulatory programs implemented by the commission.

EFFECTIVE: September 1, 2001.

7. ACT: Act of June 14, 2001, 77th Leg., R.S., ch. 934, §§ 1 - 4, 2001 Sess. Law Serv. 1766.³²⁰ (S.B. 687)

ISSUE: RELATING TO CRIMINAL PENALTIES FOR THE INTENTIONAL OR KNOWING DISCHARGE OF WASTE OR POLLUTANTS.

SUMMARY: This Act increases from one year to five years the confinement period penalty for the offense of knowingly discharging, including discharging from a point source, a waste or pollutant into or adjacent to water in the state.

EFFECTIVE: June 14, 2001.

C. TAXES

1. ACT: Act of May 15, 2001, 77th Leg., R.S., ch. 117, §§ 1 - 2, 2001 Sess. Law Serv. 215.³²¹ (H.B. 1100)

319. Codified as TEX. WATER CODE § 5.127 (Vernon Supp. 2001).

320. Codified as an amendment to TEX. WATER CODE §§ 7.145(a), 7.145(b), and repealing TEX. WATER CODE § 7.146 (Vernon Supp. 2001).

321. Codified as TEX. TAX CODE §§ 21.031(g), 21.031(h), and amending TEX. TAX CODE § 21.031(c) (Vernon Supp. 2001).

ISSUE: RELATING TO THE PRESUMPTION THAT CERTAIN VESSELS AND OTHER WATERCRAFT ARE LOCATED IN THIS STATE ONLY TEMPORARILY FOR AD VALOREM PURPOSES.

SUMMARY: This Act provides for an ad valorem property tax exemption for special purpose vessels under construction, such as off-shore drilling vessels, as well as vessels to be used in interstate commerce. This Act also provides for a tangible personal property exemption for such property intended to be incorporated into such a vessel.

EFFECTIVE: January 1, 2002.

2. **ACT:** Act of June 17, 2001, 77th Leg., R.S., ch. 1444, §§ 1 -3, 2001 Sess. Law Serv. 4860.³²² (H.B. 1241)

ISSUE: RELATING TO THE PURCHASE OF DIESEL FUEL BY CERTAIN PERSONS USING A SIGNED STATEMENT.

SUMMARY: This Act provides for a motor fuels tax exemption for the first sale or use of diesel if it will be consumed by the purchaser in oil and gas production. The exemption amount is up to 7,400 gallons in a single transaction and up to a total of 25,000 gallons per month.

EFFECTIVE: September 1, 2001.

3. **ACT:** Act of June 14, 2001, 77th Leg., R.S., ch. 881, §§ 1 - 2, 2001 Sess. Law Serv. 1673.³²³ (H.B. 3121)

ISSUE: RELATING TO EXEMPTIONS FROM AD VALOREM TAXATION FOR PROPERTY USED TO CONTROL POLLUTION.

SUMMARY: This Act requires the TNRCC to establish, by rule, specific standards by which applications for the determination of whether property is used for pollution control to ensure that property used for the production of goods and services not be exempt. This Act also requires the TNRCC to advise an applicant and the appropriate appraisal district of the agency's determination of whether a facility, device, or method is used wholly or partly to control pollution, and if applicable, the proportion of the property that is pollution control property. The person seeking the exemption or the chief appraiser, within 20 days of receipt of the notice, is authorized to appeal the executive director's determination to the commission.

EFFECTIVE: September 1, 2001.

4. **ACT:** Act of May 3, 2001, 77th Leg., R.S., ch. 41, §§ 1 - 3, 2001 Sess. Law Serv. 68.³²⁴ (S.B. 640)

322. Codified as TEX. TAX CODE §153.001(37), and amending TEX. TAX CODE §§ 153.205(a), 153.205(b), 153.205(i), 153.209(c) (Vernon Supp. 2001).

323. Codified as TEX. TAX CODE §§ 11.31(h) - (j), and amending TEX. TAX CODE §§ 11.31(d) - (g) (Vernon Supp. 2001).

324. Codified as TEX. TAX CODE §§ 111.0625, 111.0626, and amending TEX. TAX CODE § 111.063 (Vernon Supp. 2001).

ISSUE: RELATING TO ELECTRONIC FILING OF CERTAIN TAX REPORTS AND PAYMENTS.

SUMMARY: This Act requires taxpayers owing more than \$100,000 in annual taxes to make payments via electronic funds transfer and provides an option for any taxpayer owing less than \$100,000 in annual taxes to pay via electronic funds transfer. In addition, this Act requires electronic filing of the tax data reports required under the oil production tax, the natural gas production tax, the sales and use tax, and the international fuels tax agreements.

EFFECTIVE: May 3, 2001.

